BENEFIT/COST ANALYSIS OF GEOTHERMAL TECHNOLOGY R&D

Volume III: Energy Extraction and Utilization Technology

The MITRE Corporation

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Benefit / Cost Analysis of Geothermal Technology R&D

Volume III: Energy Extraction and Utilization Technology

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ABSTRACT

This document describes the benefit/cost relationship for 44 research and development (R&D) projects being funded by the Utilization Technology Branch (UTB) of the Division of Geothermal Energy (DGE), Department of Energy (DOE) as a part of its Energy Extraction and Conversion Technology program. The benefits were computed in terms of the savings resulting from the reduction in the cost of electricity projected to be generated at 27 hydrothermal prospects in the U.S. between 1978 and 2000, due to technological improvements brought about by successful R&D. The costs of various projects were estimated by referring to the actual expenditures already incurred and the projected future budgets for these projects. In certain cases, the expected future expenditures had to be estimated on the basis of the work which would need to be done to carry a project to the commercialization stage.

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EXECUTIVE SUMMARY

This report (Volume III of four volumes) describes the approach, methods, and results for benefit/cost analyses of 44 R&D projects sponsored by the Energy Extraction and Conversion Technology Program of the Utilization Technology Branch, Division of Geothermal Energy, Department of Energy.

Benefits of the R&D projects were estimated as potential future cost savings in electricity production at United States liquid-dominated geothermal prospects. The estimated benefits were based on the DGE hydrothermal electric development scenario for power plant installation at 27 United States liquid-dominated geothermal prospects in the years 1979-2000, and, for projects on well-head generators, on a postulated scenario for small capacity and remote hydrothermal sites.

Important definitions for this summary are:

- R&D Subelement - A set of one or more R&D projects or contracts that promises to develop a practical commercializable product that will improve a geothermal energy system component or process.
- Sunk Costs - R&D costs incurred through FY1977 for the subelement, inflated at 10%/year to 1978 dollars.
- Planned Costs - Expected future (including FY1978) R&D costs to the Federal program. These include costs planned by DGE, and in many cases "additional" costs estimated by MITRE to be required to bring the anticipated products of the subelement to commercialization. Expressed in 1978 present value; discount rate = 10%.
- Date of Commercialization - Year in which the product of the subelement is expected to be available for commercial incorporation into geothermal wells or electric plants.
- Estimated Benefit - Savings in the costs of electricity production in the years 1979-2000 at the 27 U.S. liquid-dominated geothermal prospects included in the hydrothermal electricity development scenario. This benefit is based on technical considerations only, and is the modelled consequence of either a pessimistic or optimistic estimate of the degree to which the R&D subelement activities will alter technology performance and/or costs expressed in 1978 dollars; assumed discount rate of 10% per year.

- Degree of Success - A scaling factor between 0.0 and 1.0 that reflects MITRE's estimate of the degree to which the possible (estimated) benefit will be delivered commercially. The estimate of degree of success includes such considerations as probability of technical success in the R&D activities, competition between subelement products for shares of the same market, and sundry factors that could effect commercial use of the R&D product.
- Expected Benefit - Product of the estimated benefit and degree of success: final estimate of how much savings in the cost of electricity production is most likely to result from the R&D subelement.
- Figure of Merit - Expected benefit divided by planned R&D costs. This is the benefit/cost ratio for the R&D subelement. It disregards sunk costs, to provide a forward look of the relative merit of continued investment in the R&D subelement.
- Historical Figure of Merit - Expected benefit divided by sum of sunk plus planned costs. This value provides an estimate of the relative value of each subelement throughout its entire life-span.

The benefit/cost analysis required development of a computer model for estimating the benefits of successfully completed R&D projects. The GEOBEN model maps the impacts of successful R&D efforts on the scenario for the development of electricity generation plants at 27 liquid dominated hydrothermal prospects. The cumulative benefits of each subelement are estimated internally by discounting the cash flow stream of the estimated benefit to their present worth (1978).

The current RD&D projects of the Energy Extraction and Conversion Technology program fall in seven standard Technical Areas: Reservoir Stimulation, Fluid Extractions, Binary Technology, Prime Mover, System Studies, Well-Head Generator, and Heat Rejection. The results of the benefit/cost analyses of the projects in these areas are shown in Table S-1. The results for individual projects or group of projects are presented in the main body of this volume, and are combined for the entire program here in Figure S-1.

TABLE S-1

BENEFIT/COST RATIOS OF THE STANDARD TECHNICAL AREAS IN THE
GEOTHERMAL ENERGY EXTRACTION AND CONVERSION TECHNOLOGY R&D PROGRAM

STANDARD TECHNICAL AREA	COST (\$1000, 1978)		EXPECTED BENEFITS ¹ (MILLIONS 1978)		FIGURE OF MERIT		HISTORICAL FIGURE OF MERIT ²	
	SUNK FY77	PLANNED FY78	PESSI- MISTIC	OPTI- MISTIC	PESSI- MISTIC	OPTI- MISTIC	PESSI- MISTIC	OPTI- MISTIC
Reservoir Stimula- tion	685.	9,302.	188.0	530.9	20.2	57.1	18.8	53.2
Fluid Extraction	2,048.	3,878.	58.1	192.4	15.0	49.6	9.8	32.5
Binary Technology	4,153.	6,739.	136.4	264.7	20.2	39.3	12.5	24.3
Prime Mover	6,237.	1,899.	89.4	175.8	47.1	92.6	11.0	21.6
System Studies	1,181.	6,602.	301.5	599.9	45.7	90.8	38.7	77.0
Well Head Generator	1,218.	14,480.	14.1	33.4	1.0	2.3	0.9	2.1
Heat Rejection	908.	1,045.	23.3	36.1	22.3	34.5	11.3	16.8
Entire Program	16,430.	43,945.	810.7	1,833.2	18.4	41.7	13.4	30.4
50 MW _e Plants ³	14,849.	23,570.	771.6	1,739.4	32.7	73.8	20.1	45.3

¹Products of the estimated benefit and degree of success

²Includes sunk R&D costs

³Excludes well-heated generators and hybrid geothermal-fossil plant subelements

FIGURE S-1
EXPECTED BENEFIT VS. PLANNED PLUS ADDITIONAL R&D COST
FOR THE GEOTHERMAL ENERGY EXTRACTION AND UTILIZATION PROGRAM
(EXCLUDING PROJECTS ON HYBRID CONCEPT AND WELL-HEAD GENERATOR)

The major conclusions of this analysis are:

- The total expected benefit from the activities in the 6 standard technical areas that are not related to well-head generators (38 projects out of the total of 44 projects) is expected to be in the range of \$796 million to 1,800 million (1978 dollars).
- Six projects in the well head generator standard technical area are expected to result in a electricity cost saving of \$14 to \$33 million at remote sites, as compared with the costs of nuclear or coal-fueled electricity. In addition to the cost savings, the use of well head generators at remote sites is expected to displace the amount of fuel that would otherwise be required to generate the electricity produced from these well head generators.
- Many of the projects in this program, especially those related to well head generators, are likely to impact the development of hot dry rock and geopressured resources. The benefits associated with these areas can be substantial. Some benefits will also be derived by the direct utilization (non-electric) systems. These benefits were not estimated in this analysis.
- Most of the technological improvements expected to result from the projects in this program area are likely to be commercialized by 1985.
- The planned future costs (including the FY1978 budget) necessary for achieving these benefits are about \$44 million. The sunk costs for this program amount to about \$16 million.
- The overall benefit/cost ratio for this program (excluding the well head generator technical area) falls between 33 and 74, based on FY1978 plus anticipated future R&D costs. If well head generator projects are included and if only the previously mentioned cost saving benefits of these projects are counted, the benefit/cost ratio of the program falls between 18 and 42.
- The prime mover technical area has the highest figure of merit (benefit/cost ratio) among the seven technical areas in this program. This is the primarily the result of a large benefit from the rotary separator project.

- The largest estimated benefit is \$600 million in the case of the system studies technical area. The outputs of this technical area will impact most of the geothermal energy conversion systems, and the utilization of these outputs is not likely to require any substantial capital expenditures.
- Although the reservoir stimulation technical area does not have a high benefit/cost ratio, this technical area is relatively attractive due to its potential for offsetting some of the uncertainty about the number of production wells needed for generating a given output of electricity.

1.0 INTRODUCTION

1.1 Purpose and Scope

The purpose of the analysis documented in this report was to estimate the benefits expected to result from the successful completion of 22 subelements of the Geothermal Energy Extraction and Conversion Technology R&D Program. A Subelement is a set of interrelated projects whose successful completion is expected to produce technological improvements with an impact on the cost and/or availability of geothermal power. In some cases, a subelement is equivalent to a single project, but the more common case is that of a subelement made up of a number of projects which are undertaken in parallel and/or series, and jointly lead to a benefit. Although some of the benefits would be realized in the area of direct utilization of the hydrothermal resources, the computation of the benefits for this analysis was confined to the projected geothermal electricity generation during the next 21 years (1979 - 2000). By matching the estimated benefits with the subelement costs, benefit cost ratios were determined to evaluate the cost effectiveness of the expenditures on the subelements.

The specific goals of the analysis were to:

- Provide a uniform basis for evaluating the probable impacts of various R&D projects on the cost and/or availability of geothermal electricity at 27 designated geothermal prospects between 1979 and 2000;
- Estimate the likely technical and economic impacts of the projects constituting 21 subelements in the geothermal energy extraction and utilization technology area;

- Evaluate the relative cost effectiveness of the expenditures on these subelements;
- Present the results of this analysis in a manner that would make it easier for the responsible DOE officials to monitor the progress and the potentially changing relative importance of the various R&D subelements with regard to the DGE programmatic goals.

Although the computation of the benefits for various subelement required a fairly diverse set of linkages between the R&D activities and the associated economic impacts, an effort was made to have a uniform methodology across the three program areas within the Utilization Technology Branch. These areas are (i) Geothermal Drilling Technology, (ii) Energy Extraction and Conversion Technology, and (iii) Geochemical Engineering.

This volume of the four volume report is confined to the analysis of the R&D projects related to the extraction of geothermal fluid, its transport to the power plant, heat exchange, energy conversion (prime movers), and the disposal of the spent fluid. The specific subelements and the associated standard technical areas are listed in Section 2.0.

In line with the current orientation of the R&D activities of the UTB, the computation of the benefits was limited to geothermal electric and primarily to the projected scenario for the generation of electricity at 27 hydrothermal prospects (in the Interagency Geothermal Coordinating Council - IGCC scenario) during the time period 1979 - 2000. All these prospects are moderate to high temperature liquid dominated reservoirs with the estimated well depths not exceeding 10,000 feet.

Volume I of this report, and Section 1.2 (below) may be consulted for further details on the scope of the analysis.

This benefit/cost analysis is, by design, project-oriented rather than program-oriented. The analysis considers, almost exclusively, the impacts of R&D activities upon the future cost of producing electricity from an assumed fixed scenario of power-plant development at U.S. hydrothermal sites. This is intended to give the R&D Program Managers a forward look at the degree to which various R&D activities are most likely to impact on the types of technologies that will be used to produce geothermal electricity in the U.S. (1)

Since the analysis is not program-oriented, it specifically ignores some of the traditional aspects of federal programmatic benefit/cost analyses. For example, no attempt is made here to compare the future cost of geothermal electricity to electricity derived from other kinds of resources. Nor is there any attempt to predict the cost of electricity from specific prospects, or to predict market penetration shares at specific prospects. Such estimates will require additional analyses which could be based in part on the results presented here.

1.2 General Approach

The methodology utilized for this analysis can be split into two segments; the "general" segment which was common to all three R&D areas, and the technical/economic impact assessment segment which was formulated uniquely for each of the three R&D areas. A brief explanation of the "general" segment of the benefit computation methodology is presented below:

The benefits of each R&D project or subelement were calculated by use of the MITRE GEOBEN computer code. "GEOBEN" is the acronym for "Geothermal R&D Project Benefits Analysis" code. The input to GEOBEN is a set of quantitative impacts on technology performance or cost expected to result upon successful completion of an R&D project or group of projects in a certain year. GEOBEN translates each input into an estimate of the total dollar savings those impacts would produce at electricity plants expected to be installed at 27 United States geothermal prospects in the years 1979-2000.

GEOBEN is explained in detail in Volume I of this report. GEOBEN is a combination of MITRE's GELCOM code (Gupta and Leigh, 1978), and a new code, "SUMDIP". GELCOM translates R&D impacts into an expected cost of power at specific geothermal prospects. SUMDIP, a "Summation and Discount Program", drives GELCOM and uses the GELCOM output to calculate the discounted net total savings that would result at all of the 27 prospects during 1979-2000.

The "R&D Impact" inputs available in GEOBEN are those available in GELCOM. The reader is referred to Volume I or Reference (1) for further details, the list of input parameters, information about the scenario for plant installation, discount rates, etc.

The methodology for assessing the technical/economic benefits for the subelements in the energy extraction and conversion technology R&D

program (specialized segment of the methodology) consisted of the following steps:

Step 1: The available documentation for all the energy extraction and conversion technology R&D projects (at the DGE headquarters) was reviewed to identify the technical objectives, performance goals, latest results produced by the project and any other indications of the potential quantitative impact of various projects on the cost and availability of geothermal electric power. This documentation generally included the original proposal, progress reports, technical reports and interim results. To supplement the information extractable from the existing documentation, a letter requesting an estimate of the expected technical and economic impacts of individual subelements was sent to various Project Officers or Principal Investigators. The responses to these letters were an important element in the estimation of the quantitative benefits of the R&D projects.

Step 2: The projects with potentially overlapping technical objectives and impacts were grouped together into "Standard Technical Areas". The projects in this R&D area were grouped into seven standard technical areas. For example, all the projects/sublements focussed on enhanced well flow rate were grouped into the "Reservoir Stimulation" standard technical area. For each standard technical area, a list of the potential technical/economic impacts of the subelements was prepared and the total list of the subelements was mapped onto the list of impacts by preparing a matrix of impacts. After this, it was determined as to how these impacts would be translated into the hydrothermal electric system parameters (cost/performance) which are defined as the standard input to the MITRE cost of power model (GELCOM/GEOBEN; Volume I or Reference 1). In most cases, the GEOBEN model input values could be computed manually.

Step 3: In a few cases, the originally estimated technical/economic impact variables did not map directly onto the GEOBEN input parameters. Special GELCOM Input Models (GIMS) were developed to convert the estimated impact variables into values corresponding to the GEOBEN impact parameters.

Step 4: The data base for the R&D subelement impact estimates and GIMS was updated and refined through frequent contact with R&D contractors, DGE Program Managers,

FIGURE 1
STEPS IN BENEFIT/COST ANALYSIS METHODOLOGY

equipment manufacturers, and geothermal operators. The open literature relevant to the standard technical areas was also searched to come up with citable estimates of impacts. The scenario for the development of geothermal electric systems was also updated.

Step 5: The expected benefits associated with the successful completion of R&D subelements were computed by entering the estimated technical/economic impacts (in some cases after conversion by using GIMS) into the GEOBEN model. "Benefits" were defined as the expected savings in the cost of generating geothermal electricity at all of the 27 geothermal prospects on the basis of the IGCC projections for their development during the time period 1978-2000. Volume I of this report provides complete details of this procedure. Some of the important features of this methodology are:

- The economics of power production are impacted only for those power plants which are scheduled to come on line after the commercialization of the output of an subelement.
- The benefits due to each subelement are computed independently for each of the 27 geothermal prospects. The benefits are sensitive to the resource characteristics and the plant design to match them.
- To deal with the uncertainty associated with the development scenario, the estimated benefits were discounted to their present worth, so that the more distant benefits have a smaller weight in the aggregated benefits.

Step 6: The estimated benefits were combined with the estimates of DGE R&D costs for various projects in each subelement and the expected degree of success of the subelement to calculate the benefit/cost ratios for different subelements. An explanation of this process is presented in Volume I of this report.

Figure 1 gives an overview of the benefit/cost analysis methodology.

Implicit in the analysis is an assumption that the reference set of schedules for the growth of electricity production at 27 representative geothermal prospects, herein generally called the "hydrothermal development scenario", is a reasonable basis for estimating benefits of R&D. While it might be possible that hydrothermal-electric development will not materialize precisely as postulated in the schedules, this site-specific basis for R&D impact assessment is more realistic than generic resource utilization projections.

1.3 Organization of this Volume

This volume contains general information about the Energy Extraction and Conversion R&D Projects (Section 2.0), the details of the procedure for analyzing these projects (Section 3.0), the results of the analysis (Section 4.0) and the conclusions and recommendations (Section 5.0).

Appendix A contains the details of the analysis of individual R&D subelements in various standard technical areas.

2.0 STANDARD TECHNICAL AREAS AND PROJECT CLASSIFICATION

The Geothermal Energy Extraction and Conversion Technology R&D Program deals with the development of new methods and the improvement of the existing technology for extracting the geothermal fluid and converting the energy content of this fluid into mechanical/electric energy. The specific objectives of this program include increasing well flow rate through reservoir stimulation and pumping, the refinement and standardization of geothermal power plant design, the development of novel energy conversion technology for the utilization of resources which cannot be exploited economically by using the conventional systems, and the disposal of the spent fluid without adverse environmental effects.

There are 44 projects in this area. These projects were grouped into 21 subelements (on the basis of mutual interdependence and commonality of objectives), and each subelement was placed in one of the seven standard technical areas for this program. Figure 2 illustrates this process, and an explanation of the logic for defining the seven standard technical areas is presented below. The projects/subelements falling into various standard technical areas are also identified.

Standard Technical Area 2-1 - Reservoir Stimulation

This standard technical area consists of projects focussed on techniques for enhancing the producibility of hydrothermal reservoirs. Activities such as the development of formation fracturing techniques

FIGURE 2
AGGREGATION OF PROJECTS INTO SUBELEMENTS AND
STANDARD TECHNICAL AREAS

and the measurement of the physical, mechanical and thermophysical behavior of geothermal formations are being undertaken. The projects falling into this standard technical area include a systems study of the potential for reservoir stimulation, a study of rock mechanics, and techniques for hydrofracture of geothermal formation.

The 7 projects in this standard technical area are listed in Table 1. These projects are grouped into 3 subelements. The logic for this grouping is illustrated in Figure 3.

Standard Technical Area 2-2 - Fluid Extraction

The R&D projects dealing with technology for increasing the productivity of geothermal wells through the utilization of deep well pumps and other innovative methods are included in this standard technical area. In addition to the projects involving the development of deep well pumps, studies concerning two phase flow in wells and the suppression of scaling in the well by injecting gas into the well are underway.

There are four projects in this standard technical area. These projects are grouped into three subelements. Table 2 presents a list of the fluid extraction projects. The grouping of individual projects into various subelements is shown in Figure 4.

Standard Technical Area 2-3 - Binary Technology

The Binary Technology R&D area consists of projects involving studies of the binary working fluids, direct contact heat exchanger, shell and tube primary heat exchangers, and utilization of moderate

TABLE 1

STANDARD TECHNICAL AREA 2-1: STIMULATION TECHNOLOGY

MITRE CODE	SUB-ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-1-1	2-1-A	Stimulation Review	LASL	05ENG36* 100002	To utilize the existing hardware and experience developed for oil and gas well stimulation methods by extending the state-of-the-art to geothermal conditions.
2-1-2	2-1-A	Well Stimulation	LASL	05ENG* 100011	To develop a program to assure the availability of geothermal well stimulation methods of proven effectiveness for commercial application in early 1980's.
2-1-3	2-1-B	Liquid Explosive	Rocket Engineering	C062336	To develop a pumpable explosive stable at high temperature, suitable for geothermal well stimulation.
2-1-4	2-1-B	Downward Hydrofracture	Terra Tek	C071608	To develop techniques for fracturing rock formations by pumping water under pressure (this technique could be utilized for stimulating non-producing wells).
2-1-5	2-1-B	Stimulation Studies (RFP)	Unidentified	Not assigned	To develop specialized hardware and stimulation methods suitable for the stimulation of liquid dominated hydrothermal reservoirs. Conduct site specific and field specific experiments to demonstrate the effectiveness of the developed hardware and methods.
2-1-6	2-1-C	National Committee on Rock Mechanics	NAS/NRC	C10002* 378001	To maintain a strong national capability in rock mechanics with the eventual objective of utilizing the capability for improving well stimulation techniques.
2-1-7	2-1-C	Rock Mechanics	Terra Tek	C071608* 311004	To study the thermophysical behavior of geothermal reservoir rocks and to provide supporting data for the improvement of drilling technology, log interpretation and reservoir stimulation.

2-1-A STIMULATION STUDY

2-1-B DEVELOPMENT OF STIMULATION METHODS

2-1-C ROCK MECHANICS

FIGURE 3
RESERVOIR STIMULATION TECHNOLOGY PROJECTS
AND SUBELEMENTS

TABLE 2

STANDARD TECHNICAL AREA 2-2: FLUID EXTRACTION

MITRE CODE	SUB- ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-2-1	2-2-A	Two Phase Flow	Denver Res. Inst.	5022729	To predict accurately the geo-fluid flow rate and well bore pressure drop of self flowing wells under specified reservoir conditions for optimizing the field development strategy and well casing size selection.
2-2-2	2-2-B	Gas Lift Technology	Rogers Engineering		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.
2-2-3	2-2-C	Thermal Downwell Pump	Sperry Rs. Center	C022838	To develop and field test a thermal deep well pump for usage in geothermal wells.
2-2-4	2-2-C	Electrical Downhole Pump	Lear Jet Motors	C031307	To develop and test an electric pump for utilization in geothermal production wells.

2-2-A - WELL FLOW

2-2-B SCALE CONTROL

2-2-C DOWNHOLE PUMP

**FIGURE 4
FLUID EXTRACTION TECHNOLOGY PROJECTS
AND SUBELEMENTS**

temperature resources for the generation of electricity. The successful completion of these projects is expected to make it possible to generate electricity at a competitive cost by utilizing the moderate temperature and other resources which are not suitable for steam/flash power generation systems. Since a large proportion of the currently known hydrothermal resource base is not suitable for flash systems, rapid commercialization of the binary energy conversion technology is crucial for attaining the goals for power on line.

The fourteen projects in this standard technical area have been grouped into 5 subelements. These projects are listed in Table 3 and the relationship between different projects in various subelements is shown in Figure 5.

Standard Technical Area 2-4 - Advanced Prime Movers

This area includes projects/subelements for which the objective is to improve the energy conversion efficiency of the geothermal energy conversion systems. Since steam turbine technology is fairly standardized and improved to the extent possible in non-geothermal applications, the emphasis of this program is on the development of innovative technology which could enhance the efficiency of the mechanical conversion of the hydraulic and thermal energy in the geothermal fluid into electrical energy. These innovations include the total flow turbine and the rotary separator.

In this area there are two projects and two subelements. The projects are listed in Table 4 and are shown in Figure 6.

TABLE 3
STANDARD TECHNICAL AREA 2-3: BINARY TECHNOLOGY

MITRE CODE	SUB-ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-3-1	2-3-A	Properties of working fluids	NBS	Not known	To measure the equation of state properties of isobutane and Freon 114 over the geothermal typical range of operating conditions for the purpose of determining the suitability of these fluids as the working fluid in binary energy conversion systems.
2-3-2	2-3-B	Heat Exchange Technology and Binary Fluid Experiment	LBL	05ENG48	To determine accurately the high temperature characteristics of organic working fluids.
2-3-3	2-3-A	Binary Cycles Fluid Properties	Oklahoma University	S055249	To determine the properties of organic binary working fluids (for inclusion in the Geothermal Power Handbook)
2-3-4	2-3-C	Direct Contact Research	INEL	C071735	To develop the heat transfer correlation and design criteria for direct contact boiler, pre-heater and condenser.
2-3-5	2-3-C	Direct Contact Heat Exchanger Power Cycle	University of Utah	S071549	To develop the heat transfer relations and design criteria for direct contact heat exchange.
2-3-7	2-3-C	Second Generation Heat Exchanger	University of Utah	S071523	To fabricate a bench scale direct contact heat exchanger and test its performance in the laboratory.
2-3-8	2-3-C	Direct Heat Exchanger	LBL	05ENG48	To develop design criteria for a pilot scale direct contact heat exchanger.
2-3-11	2-3-C	2nd Generation Direct Contact Heat Exchanger	LBL	05ENG48	To fabricate a pilot scale direct contact primary heat exchanger and test its performance at a field site.
2-3-12	2-3-D	Liquid Fluidized Bed Heat Exchanger	INEL	C071375	To demonstrate via the measurement of heat transfer coefficient and cost analysis, the feasibility of fluidized bed heat exchange.
2-3-13	2-3-D	Advanced Geothermal Primary Heat Exchanger	Aerojet Energy Conversion Company	C031076	To develop and design for field testing a self cleaning heat exchanger for use in high salinity binary plant.
2-3-9	2-3-C	Direct Contact Heat Exchanger (Binary)	Ben Holt Company	C031116	To develop (design) a low cost direct contact heat exchanger to be used with heavy scaling geothermal brines.
2-3-10	2-3-C	Study and Test Direct Contact Heat Exchanger	DSS Engineers	C054893	To demonstrate the ability of a direct contact heat exchanger to operate satisfactorily at East Mesa and Raft River.
2-3-6	2-3-C	Direct Contact Heat Exchange for Geothermal Brine	Occidental	C031076	To fabricate a bench scale direct contact primary heat exchanger (for University of Utah) and test it.
2-3-14	2-3-E	Heat Exchange Test Tech. Base Coop.	EPRI	W7405ENG48

FIGURE 5
BINARY TECHNOLOGY — PROJECTS AND SUBELEMENTS

2-3-D SHELL & TUBE HEAT EXCHANGER

2-3-E BASIC HEAT EXCHANGE LOOP

FIGURE 5
BINARY TECHNOLOGY — PROJECTS AND SUBELEMENTS
(CONTINUED)

TABLE 4

STANDARD TECHNICAL AREA 2-4: PRIME MOVERS

MITRE CODE	SUB- ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-4-1	2-4-A	Total Flow Concept	LLL	05ENG48	To determine the feasibility of expanding wet steam through a total flow turbine system.
2-4-2	2-4-B	Geothermal Rotary Separator	Biphase Engines	C031228	To design and test a geother- mal well head rotary separator in which the energy loss will be less than that in conven- tional flashers.

2-4-A TOTAL FLOW TURBINE

2-4-B ROTARY SEPARATOR

FIGURE 6
PRIME-MOVERS — PROJECTS AND SUBELEMENTS

Standard Technical Area 2-5 - Systems Studies

This standard technical area is made up of projects which are aimed at synthesizing the outputs of the ongoing R&D efforts into a source book for geothermal plant designers. Geothermal energy conversion cycle optimization effort and studies dealing with the concept of hybrid geothermal-fossil fuel power plants are also included in this technical area. All these projects are aimed at the design of more efficient and less expensive geothermal energy conversion plants.

There are 9 projects in this technical area. As shown in Figure 7, these projects are grouped into three subelements. The particulars of these projects are presented in Table 5.

Standard Technical Area 2-6 - Well Head Generator

The determination of the feasibility of utilizing well head power generators is the major objective of the projects in this technical area. If it is confirmed that it is technically and economically feasible to utilize well head generators, the rate of development of geothermal resources can be expected to accelerate due to the shortening of the long lead time between the completion of a production well and the utilization of the geothermal fluid. It is anticipated that with the availability of well head generators, many small reservoirs (not capable of supporting a 50 MW_e plant) which many not be developed otherwise, will be exploited for generating electricity. There are six projects in this area. These projects are grouped into 3 subelements as shown in Figure 8. Table 6 presents the particulars of these projects.

TABLE 5

STANDARD TECHNICAL AREA 2-5: SYSTEM STUDIES

MITRE CODE	SUB-ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-5-1	2-5-A	Optimization Studies	LBL		To identify the energy conversion cycles suitable for utilization in geothermal power plants.
2-5-2	2-5-B	Energy Conversion Cycle Analysis	NASA/JPL	A361000	
2-5-3	2-5-B	Practical Cycles for Geothermal Plants	GE	C022619	
2-5-4	2-5-B	Geothermal Energy Conversion Source Book	INEL	C071375	
2-5-5	2-5-B	Heat Rejection Systems Analysis	United Engineers	1112477	To evaluate the impact of wet/dry cooling on the total estimated cost and water consumption of cooling systems for geothermal power plants.
2-5-6	2-5-B	Power Cycle Handbook	Brown University	S024051	To provide in a source book form, an authoritative, complete, and current compilation of geothermal power plant and energy conversion information including details of existing facilities.
2-5-7	2-5-6	Energy Conversion Concepts	City of Burbank	354002	To determine the economic and energy conservation benefits of hybrid geothermal/fossil power plants. The results will be utilized on the basis for the development of geothermal energy by the City of Burbank.
2-5-8	2-5-C	Hybrid Geothermal/Fossil Power Plants	City of Burbank	354003	
2-5-9	2-5-C	Site-Specific Analysis & Design	City of Burbank	C031311

2-5-A OPTIMIZATION

2-5-B SOURCE BOOK

2-5-C HYBRID POWER PLANT

FIGURE 7
SYSTEMS STUDIES — PROJECTS AND SUBELEMENTS

TABLE 6
STANDARD TECHNICAL AREA 2-6: WELL HEAD GENERATOR

MITRE CODE	SUB-ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-6-1	2-6-A	Market Survey-Well Head Generator	NASA	A361021	To assess the market potential for a portable geothermal well head power conversion device in the 1-10 MW range.
2-6-2	2-6-A	Small Electric Generator	SANDIA	C040789	N/A
2-6-3	2-6-A	Hawaii 5-10 MW _e Steam Generator	RCUH	C031854	To prove the economic feasibility of base load power production with a flash steam generator system, and to provide long term reservoir testing.
2-6-4	2-6-B	Market Survey Well Head Generator	NASA	A361021	N/A
2-6-5	2-6-B	Gravity Head Binary Plant	SRC	C024633	To demonstrate, in an industry coupled field test, the thermodynamic and economic benefits of a binary system utilizing downhole heat exchange and a gravity head working fluid pump.
2-4-3*	2-4-C*	Helical Screw Expander	JPL/NASA	A361000	To evaluate the performance of a 1.0 MW _e helical screw expander power system at one or more geothermal sites.

* NOTE: This subelement was first assigned to Standard Technical Area 2-4 (prime movers), but was moved to Area 2-6 as it became clear that the helical screw expander size could not be easily scaled up to 50 MW_e.

2-6-A FLASH SYSTEMS

2-6-B BINARY SYSTEMS

2-4-C HELICAL SCREW EXPANDER

FIGURE 8
WELL HEAD GENERATOR — PROJECTS AND SUBELEMENTS

Standard Technical Area 2-7 - Heat Rejection

The projects in this technical area are aimed at improving the hardware and techniques for condensing the working fluid in the flash and binary systems. There are 2 projects in this standard technical area. Table 7 and Figure 9 show the particulars of these projects.

TABLE 7

STANDARD TECHNICAL AREA 2-7: HEAT REJECTION

MITRE CODE	SUB- ELEMENT NUMBER	PROJECT TITLE	CONTRACTOR	DGE CONTRACT NUMBER	TECHNICAL OBJECTIVE
2-7-1	2-7-A	Transport and Con- version of heat at moderate temperature	ORNL	05ENG28	To develop advanced heat exchanger for use in geo- thermal binary cycles with current emphasis on working fluid condenser (Fluted tubes and/or drain off skirts).
2-7-2	2-7-B	Direct Contact Research	INEL	C071375	To develop the heat transfer correlations and design criteria for direct contact boiler, pre-heater and condenser with current emphasis on experimental study of direct contact condenser.

DEVELOPMENT OF AN ADVANCED HEAT
EXCHANGER FOR USE IN GEOTHERMAL
BINARY CYCLES WITH CURRENT
EMPHASIS ON WORKING FLUID
CONDENSER (FLUTED TUBES AND/OR
DRAIN OFF SKIRTS)

2-7-A TRANSPORT & CONVERSION OF HEAT AT MODERATE TEMP.

DEVELOP HEAT TRANSFER CORRELATIONS
AND DESIGN CRITERIA FOR DIRECT
CONTACT BOILER, PREHEATER AND
CONDENSER WITH CURRENT EMPHASIS ON
DIRECT CONTACT CONDENSER

2-7-B DIRECT CONTACT RESEARCH

FIGURE 9
HEAT REJECTION — PROJECTS AND SUBELEMENTS

3.0 METHOD OF ANALYSIS

The purpose of the analysis was to calculate the Benefit/Cost for each subelement. To do this a number of intermediate tasks were carried out. The tasks are described here in sequential order.

3.1 Identification of Subelement Goal

The goal of the subelement was interpreted from the objectives of the projects contained in the subelement. The developed goal had to:

- Represent and include the R&D results that the projects are intended to achieve.
- Be a method, process, technology or piece of hardware which is able to be commercialized and, therefore, would produce an identifiable cost-reducing impact in geothermal electricity production systems.

3.2 Subelement Costs

Subelement costs are the total R&D costs of all the projects contained in the subelement. These costs include sunk and planned costs. The sunk costs (Prior to FY1978) and the planned cost for FY1978 were taken from the DGE Management Information System (MIS) sheets. (3-5) Costs planned for Fiscal years 1979-1983 were provided by DOE/DGE. Since costs for a fiscal year were provided in current year dollars, costs were discounted to 1978 dollars. A discount rate of 10% per year was used as shown below.

$$\text{Present Value (1978)} = \text{Current Year Cost} \times (1 + \text{discount rate})^{1978 - \text{current year}}$$

So that the PV(1978) of \$1,800K planned for Subelement 2-3-C in FY1979 is:

$$\$1,800K (1.10)^{1978-1979} = \$1636K$$

Other costs for Subelement 2-3-C are shown, as an example, in Table 8 where the "Prior 77" costs were assumed to be FY 1976 costs because their breakdown was not available.

3.3 Identification of Impact Parameters

Before the benefits of the subelements could be estimated, it was necessary to identify the geothermal energy system parameters which would be impacted by subelement results. These parameters were identified by examining the project objectives, subelement goal, and information about the projects supplied by the contractors. For example, the product of Subelement 2-3-C (Figure 5), which is binary direct heat exchanger development, was found to impact capital cost of heat exchange equipment, condensers and heat rejection equipment, number of wells (both production and injection wells), and plant O&M costs. These affected costs are the "impacted parameters" of the subelement.

Impacted parameters were identified from among all the parameters which might have effects on the cost of electricity. Hence, as initially identified they might not be necessarily the same as the impact variables of the GEOBEN benefits model used to quantify the effects. The capital cost of heat exchangers mentioned above is

TABLE 8

COSTS BY FISCAL YEAR FOR SUBELEMENT 2-3-C

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78→	TOTAL
2-3-4	633	300	933	0	0						0	933
2-3-5	167	0	167	0	0						0	167
2-3-6	87	34	121	0	0						0	121
2-3-7	108	0	108	0	0						0	108
2-3-8	0	142	142	0	0						0	142
2-3-9	128	0	128	0	0						0	128
2-3-10	251	156	407	50	0						50	457
2-3-11	0	0	0	1050	1800	0					2850	2850
TOTAL	1374	632	2006	1100	1800						2900	4906
\$78	1663	695	2358	1100	1636						2736	3994

part of a GEOBEN input variable called Cost of Process Mechanical (Utility). When this occurred, the appropriate mathematical relationship between the impacted parameters and input variables of the benefit model had to be worked out.

The identified impacts of the Extraction and Utilization Technology Program R&D Projects are shown in Tables 9 through 14. The projects in Standard Technical Area 2-6 are not included in these tables since their impacts are direct ones on electricity from other resources (nuclear, fossil fuels, hydroelectric generation, etc.). Instead their impacts are measured in the amount of electrical energy they will result in saving (see Sections 20.0&21.0, Appendix A).

3.4 Analysis for the Impacts on System Parameters

"System Parameters" here are the input variables of the GEOBEN benefit model. The impacts on system parameters were estimated by comparing the costs or performance of current technology with those of the new technology to be developed by the R&D subelement. For example, the analysis in Appendix A indicates that the product of Subelement 2-3-C, if brought to practice and used, would reduce the capital cost of heat exchangers by between 34.7% and 59.4% percent.

Since the analysis is primarily an estimate of future impacts, establishment of absolute magnitudes was impossible. It was deemed appropriate to postulate a range of changes rather than a single-valued change (e.g., the range of 34.7% to 59.4% above. The range limits are called pessimistic and optimistic estimates. The pessimistic and optimistic estimates are used to reflect the uncertainty

TABLE 9

IMPACTS OF THE EXTRACTION AND
UTILIZATION TECHNOLOGY PROGRAM

TECHNICAL AREA 2-1: RESERVOIR STIMULATION

PROJECTS	IMPACTED PARAMETERS			
	NUMBER OF PRODUCTION WELLS	NUMBER OF INJECTION WELLS	COST PER PRODUCTION WELL	COST PER INJECTION WELL
Stimulation Review	X	X	X	X
Well Stimulation	X	X	X	X
Stimulation Studies	X	X	X	X
National Committee on Rock Mechanics			X	X
Rock Mechanics			X	X
Liquid Explosive	X	X	X	X
Downward Hydrofracture	X	X	X	X

TABLE 10

IMPACTS OF THE EXTRACTION AND UTILIZATION TECHNOLOGY PROGRAM

TECHNICAL AREA 2-2: FLUID EXTRACTION

PROJECTS	IMPACTED PARAMETERS							
	NUMBER OF PRODUCTION WELLS	COST PER PRODUCTION WELL	PRODUCER WELL O&M COST FACTOR (LOW SAL.)	PRODUCER WELL O&M COST FACTOR (HIGH SALINITY TEMPERATURE <232°C)	PRODUCER WELL O&M COST FACTOR (HIGH SALINITY TEMPERATURE >232°C)	PRODUCER DEEP WELL PUMP O&M COST FACTOR (FLASH) TEMP. <200°C	LIFE SPAN PRODUCER WELLS (LOW SALINITY)	LIFE SPAN PRODUCER WELLS (HIGH SALINITY)
Two Phase Flow	X	X						
Gas Lift Technology	X	X	X	X	X		X	X
Thermal Downwell Pump	X					X		
Electrical Downhole Pump	X					X		

TABLE 11

IMPACTS OF THE EXTRACTION AND UTILIZATION TECHNOLOGY PROGRAM
 TECHNICAL AREA 2-3: BINARY TECHNOLOGY

PROJECTS	IMPACTED PARAMETERS						
	NUMBER OF PRODUCTION WELLS	CAPITAL COST OF TURBINE GENERATORS	CAPITAL COST OF PROCESS MECH. (UTIL.)	CAPITAL COST OF PIPING AND INSULATION	CAPITAL COST OF CONDENSER & HEAT REJECTION EQUIPMENT	UTILITY PROCESS MECH. O&M COST FACTOR (BINARY SYSTEM)	UTILITY GENERAL O&M COST FACTOR (BINARY SYSTEM)
Properties of Working Fluids	X						
Binary Cycles Fluid Prop.	X						
Heat Exchange Technology and Binary Fluid Experiment						X	
Direct Contact Research	X	X	X	X	X		X
Direct Contact Heat Exchanger Power Cycle	X	X	X	X	X		X
2nd Generation Heat Exchanger	X	X	X	X	X		X
Direct Contact Heat Exchanger for Geothermal Brine	X	X	X	X	X		X
Direct Heat Exchanger	X	X	X	X	X		X
Direct Contact Heat Exchanger (Binary)	X	X	X	X	X		X
Study and Test Direct Contact Heat Exchanger	X	X	X	X	X		X
2nd Generation Direct Contact Heat Exchanger	X	X	X	X	X		X
Liquid Fluidized Bed Heat Exchanger			X			X	
Heat Exchange Test Tech. Base Coop							
Advanced Geothermal Primary Heat Exchanger			X			X	

TABLE 12

IMPACTS OF THE EXTRACTION AND
UTILIZATION TECHNOLOGY PROGRAM

TECHNICAL AREA 2-4: ADVANCED PRIME MOVERS

PROJECTS	IMPACTED PARAMETERS				
	NUMBER OF PRODUCTION WELLS	CAPITAL COST TURBINE GENERATOR	CAPITAL COST PROCESS MECH. (UTILITY)	CAPITAL COST PIPING & INSULATION	UTILITY GENERAL O&M COST FACTOR (FLASH SYSTEM)
Total Flow Concept	X				X
Geothermal Rotary Separator	X	X	X	X	X

TABLE 13

IMPACTS OF THE EXTRACTION AND
UTILIZATION TECHNOLOGY PROGRAM

TECHNICAL AREA 2-5: SYSTEMS STUDIES

PROJECTS	IMPACTED PARAMETERS	NUMBER OF PRODUCTION WELLS	CAPITAL COST OF ENGINEERING AND ADMINISTRATION (UTILITY)
Optimization Studies			X
Energy Conversion Cycle Analysis		X	X
Practical Cycles for Geothermal Plants		X	X
Geothermal Energy Conversion Source Book		X	X
Heat Rejection Systems Analysis		X	X
Power Cycle Handbook		X	X
Energy Conversion Concepts			
Hybrid Geothermal/Fossil Power Plants			
Site Specific Analysis and Design			

TABLE 14
 IMPACTS OF THE EXTRACTION AND UTILIZATION
 TECHNICAL AREA 2-7: HEAT REJECTION

PROJECTS	IMPACTED PARAMETERS	
	CAPITAL COST OF CONDENSER AND HEAT REJECTION EQUIPMENT	UTILITY GENERAL O&M COST FACTOR (BINARY SYSTEM)
Transport and Conversion of Heat at Moderate Temperature	X	X
Direct Contact Research	X	

inherent in these future oriented analyses.

In cases where an impacted parameter under consideration was not a system parameter, additional calculations were made. The change from 34.7% to 59.4% in the heat exchanger cost due to the impact of subelement 2-3-C was converted to the change in the cost of process mechanical (utility plant) by multiplying it by a known factor 0.60. The factor 0.6 is the cost ratio of heat exchangers over process mechanical equipment of the utility plant. Thus the impacts on the system parameter "Process Mechanical (Utility) Cost" of Subelement 2-3-C are somewhere between 20.8% and 35.6%.

3.5 Impact Year

The impact year of the subelement is the year when the results of the subelement can be used and commercialized. It was determined from the reported contractor's schedule.

The GEOBEN benefits model assumes that an engineering/technology improvement must be available for two years prior to the "on-line" date for a geothermal power plant in order to be incorporated into and reduce the cost of the plant. Thus, an improved heat exchanger available at the start of 1985 (impact year) would be incorporated only into plants going into service at the end of 1986 (on-line year) and later.

In the cases where developmental refinements are required after the year of commercialization, the year of impact was selected by a balanced consideration of contractor's schedule and estimated impacts

of system parameters.

3.6 Degree of Success

The impacts on system parameters of the subelement were estimated by assuming that:

- The R&D activities will be successfully completed and their objectives are achieved.
- Other projects or subelements which impact the same system parameters will not affect the use of the new technology developed in the subelement under consideration.

Thus the benefit estimated for each subelement might be idealistic. It neglects partial success or lack of success during R&D efforts, and assumes that the product of R&D will in fact be used in all plants where it could be used. To account for losses between R&D goals and commercial use of R&D products, a "degree of success" was estimated for each subelement.

The Degree of Success of a subelement is defined as a factor that includes the possibility of partial success and partial use of the subelement results. It was estimated by examining the R&D approach, and by estimating the share of market of the resulting technology relative to existing technology and technology currently being developed. The estimate also considered market factors which are not considered in the GEOBEN benefits model.

A subelement that involves basically compiling measurements and disseminating collected information would have a degree of success of 1.0 because, although the disseminated information might not be

accurate, there is no great reason for the task of making the measurements and reporting them to be partially successful. Another subelement (such as 2-3-C) which involves the development of direct contact heat exchangers would share the market with a subelement involving the development of shell and tube heat exchangers. The Degree of Success of these two subelements might be different but must add to unity, or to less than unity if the R&D approaches of either one or both seem unlikely to achieve their goals.

Estimating the Degree of Success was facilitated by dividing the required R&D work into six different (often sequential) types of R&D activities. The types of work are based in part on the Department of Defense Categories for describing defense R&D projects, with modifications to match special characteristics of DGE program policies (1).

The six types of work are:

- (i) Preliminary Study - Initial analysis and R&D technical planning efforts to determine the general merit of new R&D concepts. This may include literature searches, gathering of expert opinion, technology forecasting, etc. The product of such studies is advice about what, if any, R&D efforts should be undertaken to develop the concept into a commercially useful product.
- (ii) Basic Research - Scientific study and experimentation directed toward increasing knowledge and understanding in those fields of science related to long-term geothermal energy production needs. It provides fundamental knowledge for the solution of identified technical and engineering problems. It also provides part of the base for exploration and development of advanced technology and new or improved functional capabilities.

- (iii) Exploratory Development - The dominant characteristic of this type of effort is that it is pointed toward specific geothermal technology problem areas and opportunities to develop proposed solutions, determining their parameters, and evaluating their feasibility and practicality. Such efforts vary from fairly fundamental applied research to quite sophisticated broad-based hardware, study, programming, and planning efforts. Such efforts thus may include minor engineering and development work to prove the feasibility of technical components of a proposed solution if carried out to assess the value of the system as a whole. The main output of such efforts are paper reports of designs and analyses of designs of new or improved technology for producing or utilizing geothermal energy. Evaluation of the value of these outputs relies on expert review and development of consensus within the technical branches of the Division of Geothermal Energy.
- (iv) Advanced Development - Includes all projects which have moved into the development of hardware for experimental and engineering tests. These projects result in hardware devices that are viewed as engineering prototypes whose size of performance scale falls short of that of products designed to be components of geothermal energy extraction or production systems. Evaluation of these prototype devices will typically be based on expert review of engineering performance data provided by the contractor who develops the device.
- (v) Engineering Development - These projects develop hardware devices with characteristics and performance on a scale deemed to be appropriate for components of commercial geothermal energy systems. Evaluation of these devices will be based on operational tests conducted by contractors other than the developing contractor. The emphasis is on achieving performance that significantly reduces the overall cost of producing and utilizing geothermal energy.
- (vi) Demonstration and Commercialization - Activities and projects intended to induce the commercial sector to utilize new technology with proven performance/cost improvements. Evaluation of these activities is based on a combination of expert opinion and technology utilization assessment.

The stage or stages into which each subelement fell at the start of F.Y. 1978 was estimated, and indicated in the analysis. The likelihood of technical success was assumed, in general to increase as a subelement moved through the stages.

By the time a subelement reaches stage v, there has usually been accumulated enough test data to allow fairly good estimates of the technical impact of the subelement on future electric power systems. The likelihood of technical success is then high, and market penetration factors then begin to dominate the estimated Degree of Success.

3.7 Final Calculations

The procedure up to this point generated four quantitative estimates: R&D costs, impacts on system parameters, year of impacts and degree of success. In the subsequent steps of the procedure, the impacts on system parameters and year of impact were used as inputs to the GEOBEN computer model to calculate the estimated benefit. Pessimistic and optimistic estimates were made separately, corresponding to the pessimistic and optimistic estimates of technical impacts on system parameters.

Each estimated benefit was then multiplied by Degree of Success to find the expected benefit, the cost reduction actually anticipated to occur.

The final benefit/cost ratios were calculated by dividing the expected benefit by estimated R&D costs. Two estimates of R&D cost were made for different purposes. For purposes of inputs to decisions about project selection, only current (F.Y. 78) plus future R&D costs are placed in the denominator of the benefit/cost ratio. This forward-looking benefit/cost ratio is called the "Figure of Merit". It does not consider sunk costs, specifically to steer away from any tendency to throw good money after bad.

The second estimate of R&D costs included sunk costs as well as current plus future costs. The benefit/cost ratio based on these total costs is called the "Historical Figure of Merit" to emphasize the relative merit of each subelement through its entire history, from actual beginning to predicted conclusions.

Thus the analysis culminates in four estimates of benefit/cost ratio which indicate the influence of pessimistic and optimistic estimates of impact, and the absence or presence of consideration of sunk costs.

4.0 RESULTS

In this section, the results of benefit/cost analysis of the Geothermal Energy Extraction and Conversion Technology R&D Program are summarized. The parameters expected to be impacted by various subelements are identified in Table 15. It can be observed that most of the subelements impact more than one system parameter.

Table 16 shows the details of the costs, estimated system parameter impacts, the optimistic and pessimistic estimates of the benefits expected from completely successful projects, the likely degree of success, and the benefit/cost ratio estimates for the three subelements in Standard Technical Area 2-1 (Reservoir Stimulation). The logic which led to the identification and estimation of the impact on the cost/performance parameters of the geothermal power systems is explained in Appendix A. In Table 16, the sunk cost figure represents the cost incurred on each subelement prior to the start of FY 78. The planned cost estimate includes the FY 78 expenditure along with the expenditures that are expected to be incurred prior to the commercialization of the output of the subelement. In certain cases, the MITRE analysts had to specify projects which will be necessary for carrying the subelement from the termination point of the last planned project (in DGE plans) to the stage at which the subelement output is ready for commercialization. This process resulted in the determination

TABLE 15

HYDROTHERMAL ELECTRICAL POWER SYSTEM PARAMETERS IMPACTED BY R&D SUBELEMENT

SYSTEM PARAMETER	STANDARD TECHNICAL AREA (CODE)													
	2-1			2-2			2-3				2-4		2-5	
	SUBELE- MENT CODE			SUBELE- MENT CODE			SUBELE- MENT CODE				SUBELE- MENT CODE		SUBELE- MENT CODE	
	2-1-A	2-1-B	2-1-C	2-2-A	2-2-B	2-2-C	2-3-A	2-3-B	2-3-C	2-3-D	2-3-E	2-4-A	2-4-B	2-5-A
<u>PRODUCER - Capital</u>														
Cost Per Production Well	X	X	X	X	X									
Cost Per Injection Well	X	X	X									X		
Cost of Gathering Systems												X		
Cost of Process Mechanical												X		
<u>UTILITY - Capital</u>														
Capital Cost of Turbine Generator								X	X			X	X	X
Capital Cost of Process Mechanical								X	X			X	X	X
Capital Cost of Piping and Insulation								X					X	
Capital Cost of Condenser and Heat Rejection Equipment								X				X	X	
Capital Cost of Engineering and Administration													X	X
<u>PRODUCER - O & M Costs</u>														
Producer Well O & M Cost Factor (LS)*					X									
Producer Well O & M Cost Factor (HS*, <232°C)					X									
Producer Well O & M Cost Factor (HS, >232°C)					X									
Deepwell O & M Cost Factor (F) ^Δ						X								
<u>UTILITY - O & M Costs</u>														
Utility General O & M Cost Factor (F)												X	X	
Utility General O & M Cost Factor (B) ^Δ								X						
Utility Process Mechanical O & M Cost Factor (B)									X	X				
<u>EQUIPMENT - Plant Life</u>														
Production Well Life (LS)					X									
Production Well Life (HS)					X									
<u>NUMBER OF WELLS</u>														
Number of Production Wells	X	X		X	X	X	X		X			X	X	X
Number of Injection Wells	X	X										X		

* LS - Low Salinity; HS - High Salinity

^ΔF - Flash; B - Binary

+ These subelements were not evaluated by using GEOBEN model

TABLE 16

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-1: RESERVOIR STIMULATION

MITRE S.E.* CODE	SUBELEMENT TITLE (CONTRACTOR)	COST (10 ³ \$ 78)		DATE OF COMM.	EXPECTED IMPACT ON ENGINEERING & ECO- NOMIC VARIABLES	ESTIMATED CHANGE IN HYDROTHERMAL ELECTRIC POWER COST MODEL PARA- METERS DUE TO THIS SUBELEMENT	ESTIMATED BENEFIT (10 ⁶ \$ 78)		DEGREE OF SUCCESS	ESTIMATED BENEFIT COST RATIO	
		SUNK PRE-FY77 + FY77	PLANNED FY78 ONWARD				PESSI- MISTIC	OPTI- MISTIC		PESSI- MISTIC	OPTI- MISTIC
2-1-A	Well Stimula- tion Analysis and Modeling (LASL)	58	150	1987	- Increased average well flow rate - Increased average cost per produc- tion and injection wells	- Equivalent to 5-13.2% reduction in well cost for the same baseline flow requirements	29.4	77.5	0.8	156.7	413.0
2-1-B	Development of Stimulation Methods (Rocket Engineering, Terra Tek)	411	7,261	1987	- Increased average well flow rate - Increased average cost per produc- tion and injection wells	- Equivalent to 5-13.2% reduction in well cost for the same baseline flow requirements	176.3	465.0	0.8	19.4	51.2
2-1-C	Rock Mechanics (NRC, Terra Tek)	215	1,891	1981	- Reduced cost of production and injection wells	- 1.25-3.3% reduction in the average cost cost of production and injection wells	29.4	77.5	0.8	12.4	32.8

of the expected date of commercialization.

The estimated impacts column presents two related impacts of the successful completion of the subelement. The estimated system performance parameter impacts (engineering/economic) of each subelement are specified along with the expected impact on the parameters utilized for computing the cost of power through the GELCOM/GEOBEN models. The next column shows the cumulative benefits expected to result from the successful completion of the R & D subelement. The estimates are based on the assumption that the postulated scenario for the development of geothermal electrical power systems will be realized.

The estimated degree of success gives an indication of the fraction of the total benefits that can be expected when one realizes that factors such as restricted market penetration, competing technological improvements, and lack of skilled manpower may prevent the subelement from achieving the maximum projected benefits. The last column of this table shows the estimated benefit/cost ratios for each subelement. The cost figures used in these estimates are the planned costs for various subelements. It is logical to use the planned costs, rather than the total costs because the benefit/cost ratio estimates should influence the decisions concerning the future costs alone. The inclusion of the sunk costs in the computation of benefit/cost ratios is for historical interest and is shown in Tables 23 and 24 of Section 5.0.

The results of the benefit/cost analyses of the subelements in Standard Technical Areas 2-2, 2-3, 2-4, 2-5, 2-6, and 2-7 are presented in Tables 17, 18, 19, 20, 21, and 22, respectively.

TABLE - 17

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-2: FLUID EXTRACTION

Mitre S.E.* Code	Subelement Title (Contractor)	Cost (10 ³ \$ 78)		Date Of Comm.	Expected Impact on Engineering & Eco- nomic Variables	Estimated Change In Hydrothermal Electric Power Cost Model Para- meters Due to This Subelement	Estimated Benefit (10 ⁶ \$ 78)		Degree Of Success	Estimated Benefit Cost Ratio	
		Sunk Pre-FY77 + FY 77	Planned FY78 Onward				Pessi- mistic	Optimistic		Pessi- mistic	Opti- mistic
2-2-A	Two Phase Flow (Denver Re- search Insti- tute)	450	828	1983	-Increased flow rate in production wells -Increased cost per production well	-Reduce the number of production wells by 10% -Increase average cost per production well by 10%	3.4	76.4	0.5	2.1	46.1
2-2-B	Gas Lift Tech- nology (Rogers Engineering)	0	518	1981	-Reduced production well O&M cost -Prolonged product- ion well life -Increased capital cost of production wells	-Reduce O&M cost of pro- duction wells at low salinity sites by 5 to 10% -Reduce O&M cost of pro- duction wells at high salinity sites by 25 to 30% -Increase production well life by 20 to 30% -Increase production well capital costs by 5 to 12.5%	0.0	31.5	0.5	0.0	30.4
2-2-C	Downhole Pumps (Sperry Re- search Center; Lear)	1598	2532	1983	-Decreased downhole pump O&M costs -Increased flow rate for product- ion wells	-Reduce number of pro- duction wells by 3 to 5% -Reduce O&M costs of downwell pumps by 30 to 45%	62.7	153.8	0.9	22.3	54.7

* S.E. - Subelement

TABLE - 18

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-3: BINARY TECHNOLOGY

Mitre S.E.* Code	Subelement Title (Contractor)	Cost (10 ³ \$ 78)		Date Of Comm.	Expected Impact on Engineering & Eco- nomic Variables	Estimated Change In Hydrothermal Electric Power Cost Model Para- meters Due to This Subelement	Estimated Benefit (10 ⁶ \$ 78)		Degree Of Success	Estimated Benefit Cost Ratio	
		Sunk Pre-FY77 + FY77	Planned FY78 Onward				Pessi- mistic	Opti- mistic		Pessi- mistic	Opti- mistic
2-3-A	Working Fluid Properties (NBS, Okl. Univ.)	257	407	1982	-Increased Utiliza- tion efficiency	-Decrease the number of production wells by 0-0.2%	0.0	1.3	1.0	0.0	3.2
2-3-B	Heat Exchanger & Binary Flu- ids (L.B.L.)	1,311	939	1982	-Reduced size and material cost of primary heat ex- changers	-Reduce the capital cost of primary heat ex- changer by 3 to 8%	4.3	11.6	1.0	4.6	12.4
2-3-C	Binary Direct Contact Heat Exchange (L.B.L., Univ. of Utah)	2,378	2,736	1982	-Increased utiliza- tion efficiency -Reduced plant O&M costs	-Reduce number of pro- duction and injection wells by 2 to 4% -Reduce process mechan- ical costs by 20 to 35% -Reduce condenser and heat rejection equip- ment plant costs by 2 to 5% -Reduce general plant O&M costs by 5 to 10%	217.2	404.8	0.6	47.6	88.8
2-3-D	Binary Shell Tube Heat Ex- change (I.N. E.L., Aerojet)	307	1,912	1983	-Reduced size and increased mainten- ance requirements of heat exchanger	-Reduce the capital cost of heat exchanger by 10-23% -Increase heat exchanger O&M costs by 160-200%	0.0	11.2	0.6	0.0	3.5
2-3-E	Basic Heat Exchange (EPRI)	0	745	1981	-Increased effi- ciency of heat exchangers	-Reduce process mechan- ical O&M cost (binary) by 6 to 12% -Reduce Process mechan- ical capital cost (utility) by 7.1 to 8.4%	1.8	2.2	1.0	2.4	3.0

* S.E. - Subelement

TABLE 19

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-4: PRIME MOVERS

MITRE S.E. CODE	SUBELEMENT TITLE (CONTRACTOR)	COST (10 ³ \$ 78)		DATE OF COMM.	EXPECTED IMPACT ON ENGINEERING & ECO- NOMIC VARIABLES	ESTIMATED CHANGE IN HYDROTHERMAL ELECTRIC POWER COST MODEL PARA- METERS DUE TO THIS SUBELEMENT	ESTIMATED BENEFIT 10 ⁶ \$ 78)		DEGREE OF SUCCESS	ESTIMATED BENEFIT COST RATIO	
		SUNK PRE-FY77 + FY 77	PLANNED FY78 ONWARD				PESSI- MISTIC	OPTI- MISTIC		PESSI- MISTIC	OPTI- MISTIC
2-4-A	Total Flow Concept (LLL)	5,965	1,520	1981	- Increased Utiliza- tion efficiency - Increased plant O&M	- Reduce the number of production and injec- tion wells by 2-15% - Increase plant O&M costs by 12-34% - Increase capital cost of Condenser and heat rejection system by 11-13 % - Increase capital cost of turbine generator by 3-6% - Reduce cost of gather- ing systems by 10-20% - Reduce cost of producer process mechanical by 40%	4.7	207.1	0.03	0.0	4.1
2-4-B	Rotary Separat- or (Biphase Energy Systems)	272	379	1982	- Increased utiliza- tion efficiency - Smaller plant size	- Decrease the number of production and injec- tion wells by 12-20% - Increase cost of tur- bine generator by 5.7- 9.1% - Decrease process mech- anical (utility) costs by 16-20.6% - Decrease cost of con- denser and heat re- jection system by 7.3-12.5%	148.8	282.6	0.6	236.0	447.0
2-4-C	Helical Screw Expander (JPL/NASA)	921	430	1991	- This subelement will not impact the engineering and economic vari- ables associated with the conven- tional geothermal power plant. The helical screw expander will be used for generat- ing electricity at the well head.	- \$2,300K to \$5,500K savings in electricity costs as compared with cheapest alternative electricity	2.3	5.5	0.9	4.8	11.5

TABLE 20

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-5: SYSTEM STUDIES

MITRE S.E.* CODE	SUBELEMENT TITLE (CONTRACTOR)	COST (10 ³ \$ 78)		DATE OF COMM.	EXPECTED IMPACT ON ENGINEERING & ECO- NOMIC VARIABLES	ESTIMATED CHANGE IN HYDROTHERMAL ELECTRIC POWER COST MODEL PARA- METERS DUE TO THIS SUBELEMENT	ESTIMATED BENEFIT (10 ⁶ \$ 78)		DEGREE OF SUCCESS	ESTIMATED BENEFIT COST RATIO	
		SUNK PRE-FY77 + FY77	PLANNED FY78 ONWARD				PESSI- MISTIC	OPTI- MISTIC		PESSI- MISTIC	OPTI- MISTIC
2-5-A	Optimization Studies (LBL)	0	250	1981	-Improved utilization efficiency -Reduction in plant capital costs	-Reduce the cost of generated power by 8 to 15%	400	750	0.6	960.0	1800.0
2-5-B	Geothermal Power Handbook (Brown Univ., JPL, NASA, G.E., INEL)	818	457	1981	-Increased utilization efficiency -Reduced plant engineering cost	-Reduce the number of production and injection wells by 0.5 to 1% -Reduce plant engineering costs by 1.5 to 2%	36.5	89.5	1.0	80.0	196.0
2-5-C	Hybrid Geothermal/Fossil Power Plants (City of Burbank)	363	5,895	1982	-This concept will result in a saving of 10% of the least expensive fossil fuel needed for generating equivalent units of electricity	-\$50,000K to \$120,750K savings in electricity production costs	50	121	0.5	4.2	10.2

* S.E. - Subelement

TABLE - 21

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-6: WELL HEAD GENERATOR

Mitre S.E. Code	Subelement Title (Contractor)	Cost (10 ³ \$ 78)		Date Of Comm.	Expected Impact On Engineering & Eco- nomic Variables	Estimated Change In Hydrothermal Electric Power Cost Model Para- meters Due to This Subelement	Estimated Benefit (10 ⁶ \$ 78)		Degree Of Success	Estimated Benefit Cost Ratio	
		Sunk Pre-FY77 + FY 77	Planned FY78				Pessi- mistic	Opti- mistic		Pessi- mistic	Opti- mistic
2-6-A	Well Head Generator (NASA, SANDIA, Univ. of Utah)	280	5,380	1982	-This equipment will increase the amount of geothermal elec- tric energy genera- ted. The Well Head generators will make it possible to shor- ten the time period between production well completion and power generation. These generators will also enable the developers to utilize small sized and remotely loca- ted reservoirs.	- \$9,200K to \$21,900K saving in electricity costs as compared with cheapest alternative electricity	9.2	21.9	0.8	1.4	3.3
2-6-B	Gravity Head Binary Plant	17	8,670	1983	-The impact of this subelement will be similar to that of Subelement 2-6-A	- \$7,600K to \$18,200K savings in electricity costs as compared with cheapest alternative electricity	7.6	18.2	0.6	0.5	1.0

* S.E. - Subelement

TABLE - 22

RESULTS OF THE BENEFIT/COST ANALYSIS FOR THE STANDARD TECHNICAL AREA 2-7: HEAT REJECTION

Mitre S.E.* Code	Subelement Title (Contractor)	Cost (10 ³ \$ 78)		Date Of Comm.	Expected Impact On Engineering & Eco- nomic Variables	Estimated Change In Hydrothermal Electric Power Cost Model Para- meters Due to This Subelement	Estimated Benefit (10 ⁶ \$ 78)		Degree Of Success	Estimated Benefit Cost Ratio	
		Sunk Pre-FY77 + FY 77	Planned FY78				Pessi- mistic	Opti- mistic		Pessi- mistic	Opti- mistic
2-7-A	Transport & Conversion of Heat (ORNL)	908	945	1981	-Reduced size of condenser and heat rejection equipment. -Increased Utility general O&M Costs (Binary)	-Reduce the capital cost of condenser and heat rejection equipment by 4.4 to 5.6% -Increase the utility general O&M cost (bi- nary) factor by 2%	14.2	23.1	0.6	9.0	14.7
2-7-B	Direct Contact Condenser Research (INEL)	100	100	1983	-Reduced size of con- denser and heat re- jection equipment -A slight increase in utility general O&M cost factor (Binary)	-Reduce the condenser and heat rejection equipment capital cost by 4 to 6%	29.6	44.5	0.5	148.0	222.5

* S.E. - Subelement

5.0 DISCUSSION

5.1 Projects in the Context of the Program

The quantitative results of the benefit/cost analysis of the Geothermal Energy Extraction and Conversion Technology Program are summarized in Table 23. A review of the expected impacts of various subelements (Appendix A) reveals that some subelements have overlapping objectives and potential impacts. In such cases, it would be inappropriate to add the estimated benefits of different subelements. Table 24 lists the subelements ordered by the estimated figure of merit.

The relative attractiveness of various R&D program subelements is apparent in Table 24. The "Plant Optimization Studies" (2-5-A) subelement has the highest expected benefit cost ratio of 1800 (optimistic). At the other end, Basic Heat Exchange (2-3-E) subelement has an expected benefit of 3.0. Four subelements have expected benefit/cost ratios exceeding 200, and another eleven subelements have benefit/cost ratios between 10 and 196. All these subelements appear to represent an effective investment of government funds in the R&D program.

Figure 10 is a graphic representation of the data summarized in Table 24. The upper curve in the figure shows the estimated optimistic cumulative benefit of various subelements. The accumulation of the benefits was carried out by extending the curves in accordance with the order in Table 24. On the pessimistic benefits

TABLE 23
SUMMARY OF THE RESULTS

SUBELEMENT CODE	SUBELEMENT TITLE	BENEFITS (10 ⁶ \$78)		COST (10 ³ \$78)		DEGREE OF SUCCESS	YEAR OF IMPACT	FIGURE OF MERIT			
		PESS.	OPT.	PLANNED	PLANNED & SUNK			PLANNED		PLANNED & SUNK	
								PESS.	OPT.	PESS.	OPT.
2-1-A	Well Stimulation Analysis & Modeling	29.4	77.5	150	208	0.8	1987	156.7	413.0	113.0	298.1
2-1-B	Development of Stimulation Methods	176.2	465.0	7261	7672	0.8	1987	19.4	51.2	18.4	48.5
2-1-C	Rock Mechanics	29.4	77.5	1891	2106	0.8	1982	12.4	32.8	11.2	29.4
2-2-A	Two Phase Flow	3.4	76.4	828	1278	0.5	1983	2.1	46.1	1.2	29.9
2-2-B	Gas Lift Technology	0.0	31.5	518	518	0.5	1981	0.0	30.4	0.0	30.4
2-2-C	Downhole Pumps	62.7	153.8	2532	4130	0.9	1983	22.3	54.7	13.7	33.5
2-3-A	Working Fluid Properties	0.0	1.3	407	664	1.0	1982	0.0	3.2	0.0	2.0
2-3-B	Heat Exchange & Binary Fluid	4.3	11.6	939	2250	1.0	1982	4.6	12.4	1.9	5.2
2-3-C	Binary Direct Heat Exchange	217.2	404.8	2736	5114	0.6	1982	47.6	88.8	32.6	60.8
2-3-D	Binary S/T Heat Exchange	0.0	11.2	1912	2219	0.6	1983	0.0	3.5	0.0	3.0
2-3-E	Basic Heat Exchange	1.8	2.2	745	745	1.0	1981	2.4	3.0	2.4	3.0
2-4-A	Total Flow	4.7	207.1	1520	7485	0.03	1981	0.0	4.1	0.0	0.8
2-4-B	Rotary Separator	148.8	282.6	379	651	0.6	1982	236.0	447.0	137.0	260.0
2-4-C	Helical Screw Expander	2.3	5.5	430	1351	0.9	1981	4.8	11.5	1.5	3.7
2-5-A	Optimization Studies	400.0	750.0	250	250	0.6	1981	960.0	1800.0	960.0	1800.0
2-5-B	Geothermal Power Handbook	36.5	89.5	457	1275	1.0	1981	80.0	196.0	28.6	70.2
2-5-C	Analysis of Hybrid (Geothermal/Fossil Power Plants)	50.0	120.8	5895	6258	0.5	1982	4.2	10.2	4.0	9.6
2-6-A	Well Heat Generator	9.2	21.9	5380	5660	0.8	1982	1.4	3.3	1.3	3.1
2-6-B	Gravity Head Binary Plant	7.6	18.2	0552	0569	0.6	1983	0.5	1.0	0.5	1.0
2-7-A	Transport & Conversion of Heat	14.2	23.1	945	1853	0.6	1981	9.0	14.7	4.6	7.5
2-7-B	Direct Contact Con- denser Research	29.6	44.5	100	100	0.5	1983	148.0	222.5	148.0	222.5

FIGURE 10
EXPECTED BENEFIT VS. PLANNED PLUS ADDITIONAL R&D COST
FOR THE GEOTHERMAL ENERGY EXTRACTION AND UTILIZATION PROGRAM
(EXCLUDING PROJECTS ON HYBRID CONCEPT AND WELL-HEAD GENERATOR)

TABLE 24
BENEFITS AND PLANNED COSTS OF THE GEOTHERMAL ENERGY EXTRACTION AND CONVERSION TECHNOLOGY R&D PROGRAM SUBELEMENTS

SUB-ELEMENT CODE	SUBELEMENT TITLE	EXPECTED BENEFIT ¹ (\$10 ⁶ , 1978)				PLANNED COST ² (\$10 ⁶ , 1978)		FIGURE OF MERIT			
		BY SUBELEMENT		CUMMULATIVE		BY SUB-ELEMENT	CUMMU-LATIVE	(PLANNED COSTS)		PLANNED & SUNK COSTS	
		PESSI-MISTIC	OPTI-MISTIC	PESSI-MISTIC	OPTI-MISTIC			PESSI-MISTIC	OPTI-MISTIC	PESSI-MISTIC	OPTI-MISTIC
A. SUBELEMENTS WITH IMPACTS AT 50 MWe HYDROTHERMAL ELECTRIC PLANT SITES:											
2-5-A	Optimization Studies	240.0	450.0	240.0	450.0	0.250	0.250	960.	1800.	960.	1800.
2-4-B	Rotary Separator	89.3	169.6	329.3	619.6	0.379	0.629	236.	447.	137.	260.
2-1-A	Well Stimulation Analysis	23.5	96.9	352.8	716.5	0.150	0.779	157.	413.	113.	298.
2-7-B	Direct Contact Condenser Research	14.8	22.2	367.6	738.7	0.100	0.879	148.	222.	148.	222.
2-5-B	Geothermal Power Handbook	36.5	89.5	404.1	828.2	0.457	1.336	80.	196.	29.	70.
2-3-C	Binary Direct Contact Heat Exchange	130.3	242.9	534.4	1071.1	2.736	4.072	48.	89.	33.	61.
2-2-C	Downhole Pumps	56.4	138.4	590.7	1209.5	2.532	6.604	22.	55.	13.7	34.
2-1-B	Development of Stimulation Methods	141.1	372.0	731.7	1581.5	7.261	13.865	19.4	51.	18.4	48.
2-2-A	Two-Phase Flow	1.7	38.2	733.4	1619.7	0.828	14.693	2.0	46.	1.3	30.
2-1-C	Rock Mechanics	23.5	62.0	756.9	1681.7	1.891	16.584	12.4	33.	11.2	29.
2-2-B	Gas Lift Technology	0.0	15.8	756.9	1697.5	0.518	17.102	0.0	30.	0.0	30.
2-7-A	Transport and Conversion of Heat	8.5	13.9	765.4	1711.4	0.945	18.047	9.0	14.7	4.6	7.5
2-3-B	Heat Exchange and Binary Fluid	4.3	11.6	769.7	1723.0	0.939	18.986	4.6	12.4	5.2	1.9
2-4-A	Total Flow	0.1	6.2	769.8	1729.2	1.520	20.506	0.0	4.1	0.0	0.8
2-3-D	Binary Shell and Tube Heat Exchange	0.0	6.7	769.8	1735.9	1.912	22.418	0.0	3.5	0.0	3.0
2-3-A	Working Fluid Properties	0.0	1.3	769.8	1737.2	0.407	22.825	0.0	3.2	0.0	2.0
2-3-E	Basic Heat Exchange	1.8	2.2	771.6	1739.4	0.745	23.570	2.4	3.0	2.4	3.0
	SUBTOTAL	771.6	1739.4	771.6	1739.4	23.570	23.570	32.7	73.8	20.1	45.3

CONTINUED

TABLE 24 (Concluded)

BENEFITS AND PLANNED COSTS OF THE GEOTHERMAL ENERGY EXTRACTION AND CONVERSION TECHNOLOGY R&D PROGEAM SUBELEMENTS

SUB-ELEMENT CODE	SUBELEMENT TITLE	EXPECTED BENEFIT ¹ (\$10 ⁶ , 1978)				PLANNED COST ² (\$10 ⁶ , 1978)		FIGURE OF MERIT			
		BY SUBELEMENT		CUMMULATIVE				(PLANNED COSTS)		PLANNED & SUNK COSTS	
		PESSI-MISTIC	OPTI-MISTIC	PESSI-MISTIC	OPTI-MISTIC	BY SUB-ELEMENT	CUMMU-LATIVE	PESSI-MISTIC	OPTI-MISTIC	PESSI-MISTIC	OPTI-MISTIC
B. SUBELEMENTS WITH IMPACTS OF OTHER TYPES OF GEOTHERMAL ELECTRIC PLANT SITES:											
2-4-C	Helical Screw Expander	2.1	5.0	773.7	1744.4	0.430	24.000	4.8	11.5	1.5	3.7
2-5-C	Hybrid Geothermal-Fossil Plants	25.0	60.4	798.7	1804.8	5.895	29.895	4.2	10.2	4.0	9.6
2-6-A	Well Head Generator	7.4	17.5	806.1	1822.3	5.380	35.275	1.4	3.3	1.3	3.1
2-6-B	Gravity Head Binary Plant	4.6	10.9	810.7	1833.2	8.670	43.945	0.5	1.0	0.5	1.0
	SUBTOTAL	39.1	93.8	810.7	1833.2	20.375	43.945	1.9	4.6	1.8	4.3
2-X-X	ENTIRE PROGRAM	810.7	1833.2	810.7	1833.2	43.945	43.945	18.4	41.7	13.4	30.4

¹Product of estimated benefit and degree of success²Includes MITRE estimates of costs required beyond current DCE plans

curves, the subelements were ordered on the basis of decreasing optimistic benefit/cost ratios. Therefore, this curve is not smooth like the upper curve. Straight lines representing benefit/cost ratios of 10, 100 and 500 are drawn to give an indication of the range of benefit/cost ratio values for a given total expenditure (planned) on the R&D program.

The overall benefit/cost ratio estimates for the Geothermal Energy Extraction and Conversion Technology R&D Program, excluding projects on hybrid concept and well-head generator, are 32.7 (pessimistic), and 73.8 (optimistic). These estimates reflect some adjustments made for subelements with overlapping system parameter impacts. Projects on the hybrid geothermal-fossil concept and well-head generator are excluded because they do not impact the geothermal electricity generated at 27 hydrothermal prospects as specified in the hydrothermal development scenario. If these projects are included the overall benefit/cost ratio falls between 18.4 and 41.7.

5.2 Benefit/Cost Ratios of Individual Technical Areas

The estimated benefit/cost ratios for each of the seven standard technical areas are shown in Table 25. These ratios were computed by grouping together various subelements in a given subarea. The total costs and expected benefits (= estimated benefit x degree of success) for individual technical areas were added up, and the optimistic and pessimistic figures of merit were computed on the basis of these totals. All the subelements listed in Table 23 are represented in the figures presented in Table 25.

In Table 25, the costs already incurred on various subelements (prior to and including FY 1977) are shown in the "Sunk Cost" column. The "Planned Cost" is the aggregate of the costs incurred during FY 1978, and the estimated costs for the subsequent fiscal years in the lifetime of the subelement. The "Expected Benefit" is computed by multiplying the estimated benefit by the expected degree of success of the subelement. The "Figure of Merit" is based on planned costs alone; this reflects the forward looking assessment of the standard technical area at the start of FY 1978. The "Historical Figure of Merit" is based on the sum of the sunk and planned costs and represents the expected return on the F&D costs associated with the particular technical area.

TABLE 25

BENEFIT/COST RATIOS OF THE STANDARD TECHNICAL AREAS IN THE
GEOTHERMAL ENERGY EXTRACTION AND CONVERSION TECHNOLOGY R&D PROGRAM

STANDARD TECHNICAL AREA	COST (\$1000, 1978)		EXPECTED BENEFITS ¹ (\$MILLIONS 1978)		FIGURE OF MERIT		HISTORICAL FIGURE OF MERIT ²	
	SUNK FY77	PLANNED FY78	PESSI- MISTIC	OPTI- MISTIC	PESSI- MISTIC	OPTI- MISTIC	PESSI- MISTIC	OPTI- MISTIC
Reservoir Stimula- tion	685.	9,302.	188.0	530.9	20.2	57.1	18.8	53.2
Fluid Extraction	2,048.	3,878.	58.1	192.4	15.0	49.6	9.8	32.5
Binary Technology	4,153.	6,739.	136.4	264.7	20.2	39.3	12.5	24.3
Prime Mover	6,237.	1,899.	89.4	175.8	47.1	92.6	11.0	21.6
System Studies	1,181.	6,602.	301.5	599.9	45.7	90.8	38.7	77.0
Well Head Generator	1,218.	14,480.	14.1	33.4	1.0	2.3	0.9	2.1
Heat Rejection	908.	1,045.	23.3	36.1	22.3	34.5	11.3	16.8
Entire Program	16,430.	43,945.	810.7	1,833.2	18.4	41.7	13.4	30.4
50 MW _e Plants ³	14,849.	23,570.	771.6	1,739.4	32.7	73.8	20.1	45.3

¹Products of the estimated benefit and degree of success

²Includes sunk R&D costs

³Excludes well-head generators and hybrid geothermal-fossil plant subelements

The following significant observations are suggested by the numbers in Table 25.

- The total expected benefit from the activities in the 6 standard technical areas that are not related to well-head generators (38 projects out of the total of 44 projects) is expected to be in the range of \$796 million to 1,800 million (1978 dollars).
- Six projects in the well head generator standard technical area are expected to result in a electricity cost saving of \$14 to \$33 million at remote sites, as compared with the costs of nuclear or coal-fueled electricity. In addition to the cost savings, the use of well head generators at remote sites is expected to displace the amount of fuel that would otherwise be required to generate the electricity produced from these well head generators.
- Many of the projects in this program, especially those related to well head generators, are likely to impact the development of hot dry rock and geopressured resources. The benefits associated with these areas can be substantial. Some benefits will also be derived by the direct utilization (non-electric) systems. These benefits were not estimated in this analysis.
- Most of the technological improvements expected to result from the projects in this program area are likely to be commercialized by 1985.
- The planned future costs (including the FY1978 budget) necessary for achieving these benefits are about \$44 million. The sunk costs for this program amount to about \$16 million.
- The overall benefit/cost ratio for this program (excluding the well head generator technical area) fall between 33 and 74, based on FY1978 plus anticipated future R&D costs. If well head generator projects are included and if only the previously questioned cost saving benefits of these projects are counted, the benefit/cost ratio of the program falls between 18 and 42.
- The prime mover technical area has the highest figure of merit (benefit/cost ratio) among the seven technical areas in this program. This is primarily the result of a large benefit from the rotary separator project.

- The largest estimated benefit is \$600 million in the case of the system studies technical area. The outputs of this technical area will impact most of the geothermal energy conversion systems, and the utilization of these outputs is not likely to require any substantial capital expenditures.
- Although the reservoir stimulation technical area does not have a high benefit/cost ratio, this technical area is relatively attractive due to its potential for offsetting some of the uncertainty about the number of production wells needed for generating a given output of electricity.

5.3 Potential Impact of the Program on the Cost of Hydrothermal (Geothermal) Electric Power Plants

Table 24 shows that the total estimated benefits associated with the Geothermal Energy Extraction and Conversion Technology R&D Program are between \$772 million and \$1740 million, (1978 dollars). Adjustments were made for program subelements with obvious overlaps between their technical objectives, in aggregating the benefits of various technical areas. These figures represent the potential savings in the cost of generating electricity at hydrothermal power plants projected to be installed between the years 1979 and 2000 at the U.S. liquid dominated geothermal prospects in the Inter-Agency Geothermal Coordinating Council (IGCC) power-on-line scenario.

If the current technology only is assumed to apply to all the hydrothermal power plants in the IGCC scenario, the total estimated cost (capital and O&M), as estimated by the GEOBEN model, amounts to \$10.928 Billions (1978 dollars). Thus the percentage cost reductions expected from the products of the R&D projects in this program range between $(0.772/10.928) \times 100 = 7\%$ and $(1.740/10.928)$

x 100 = 16%. On the basis of the information available at the time of this analysis, these estimates appear to be realistic. However, lack of success in R&D, other than those anticipated in this analysis, and/or significant changes in the hydrothermal electric development scenario can alter these estimates.

Cost reductions in the range 7% to 16% can be sufficient for making hydrothermal electricity competitive at some individual sites. In some other cases, the cumulative impact of the R&D projects in all three programs may be barely adequate for making hydrothermal electricity competitive vs. fossil fueled or nuclear fueled electricity.

The results of this analysis should be utilized in any future site-specific evaluation of the economic prospects of electrical energy generated from liquid dominated hydrothermal resources.

5.4 Conclusions and Recommendations

The following conclusions can be made on the basis of the results of the benefit/cost analysis of the current R&D activities in the Geothermal Energy Extraction and Conversion Technology Program:

- If the projected scenario for the development of hydrothermal electric power plants turns out to be valid, the anticipated success of the projects in this program is expected to reduce the cost of geothermal electricity by 7 to 16% relative to the cost without any technological improvements.
- The estimated benefit/cost ratios for the entire program including projects on hybrid concept and well-head generator (18 and 42 pessimistic and optimistic, respectively) are sufficiently high, and this suggests that the program is likely to yield a good return on the investments.

- There are a few instances of two or more subelements having overlapping technical objectives and potential impacts. If these overlaps of benefits are eliminated by appropriate allocation of benefits, the figure of merit for certain subelements and standard technical areas will be reduced.
- The inclusion of hot dry rock and geopressured systems among the potential recipients of benefits of R&D in certain technical areas (mainly fluid extraction, binary technology and system studies) can increase the benefit/cost ratios for these technical areas significantly.

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APPENDIX A
GEOTHERMAL EXTRACTION AND CONVERSION TECHNOLOGY
R&D PROJECT BENEFIT/COST ANALYSES

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1.0 INTRODUCTION

This appendix presents the benefit analyses of the subelements in the seven technical areas discussed in the main body of this report. The subelements are identified by their code numbers and titles. A subelement code number consists of two digits and a letter. For example, Subelement Code 2-2-B identifies subelement B of technical area number 2 in program number 2, namely Extraction and Conversion Technology. Program 2 has 44 projects that are grouped into 22 subelements as shown in Figure A-1.

The analyses are based on the assessment of the potential impact of the projects constituting the subelement on the cost of geothermal power. In some cases, individual projects or groups of projects in a subelement could not be identified with a quantifiable impact on the cost of geothermal power, because additional projects would be necessary for carrying the subelement to a stage at which it will impact the cost of power. The evaluation of the benefits for these elements was preceded by the determination of the technical content, milestones and the cost of these additional projects. It was then assumed that these projects will be undertaken and the total subelements were evaluated.

In the next 22 sections, the basis and the results of the computation of benefits for various subelements are detailed. Each section (devoted to one subelement) consists of a covering summary page followed by the rationale for the analysis. The following items

are included in the write-up for each subelement.

1. Subelement Code Number and Title
2. Project(s) in the Subelement
In this section a list of the projects in the subelement is provided along with a block diagram showing the relationships among these projects, and the sequence in which the projects contribute to the achievement of the subelement goals.
3. Goal
The goal for the subelement is inferred from the objectives of various projects in the subelement.
4. Costs
The subelement costs include the sunk costs (expenditures incurred on those parts of the subelement which have already been completed), current year (Fiscal year 1978) costs, and estimated future costs of all the projects, including additional ones, contained in the subelement.
5. 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 subelement under consideration, are identified in this section.
6. Estimated Impact on System Parameters
The impact of the successful completion of the subelement on the system parameters, identified in Section 5, is estimated in this part of the evaluation. The units for these impacts are compatible with the input requirements of the benefits model (GEOBEN; the structure of this model is explained in Volume I of this report). Two estimates of impact, optimistic and pessimistic are developed for each impacted parameter.
7. Degree of Success
The impact estimates Section 6, above, are the upper bounds on the expected impacts. These impacts are likely to result only if the subelement achieves all its goals by the scheduled completion date. Recognizing the fact that either the sub-

FIGURE A-1
PROGRAM TECHNICAL AREAS AND ASSOCIATED SUBELEMENTS

element will not be a complete success and/or there may be delays in achieving the milestones for the subelement, a subjective estimate of the degree of success of the subelement is stated in this section. Subelements which are very close to the completion stage are bound to have a higher value for the expected degree of success compared with the subelements which are in the initial stages at the time of this analysis.

8. Results

In this section, the estimated cumulative benefits of the subelement are presented along with the estimated benefit/cost ratio with and without the inclusion of the sunk costs in the estimated subelement costs. The optimistic and pessimistic estimates of the cumulative benefit and figure of merit expected (benefit/cost ratio) are presented for each subelement.

It is appropriate to point out that the estimates developed in this section are based on the best information available at the time of the analysis. Due to the dynamics of the RD&D and the development of geothermal resources, the basis for the estimation of the benefits could change rapidly. Therefore, some of the results presented in this report may be outdated very soon, and would need to be revised.

2.0 SUBELEMENT 2-1-A:
STIMULATION STUDY, AND
SUBELEMENT 2-1-B:
DEVELOPMENT OF
STIMULATION METHODS

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-1-A	CONTRACT NUMBER(S)	(1) 05ENG36*100002 (2) 05ENG*100011
TITLE	Well Stimulation Analysis & Modeling		
CONTRACTOR(S)	LASL		
RELATED PROJECTS	2-1-1 Stimulation Review 2-1-2 Well Stimulation Review		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		√			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	49										49
2. DGE Planned:		150	0	0	0	0	0	0	0		150
3. Additional:											
Total:	49	150	0	0	0	0	0	0	0		199
Discounted Total of Planned and Additional:				208							

EXPECTED YEAR OF COMMERCIALIZATION	FY1987
EXPECTED DEGREE OF SUCCESS	0.80

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	77.5
	PESSIMISTIC	29.4
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	413.0
	PESSIMISTIC	156.7
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	298.1
	PESSIMISTIC	113.0

SEE ATTACHED PAGES FOR RATIONALE

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-1-B	CONTRACT NUMBER(S)	(1) C062336 (2) C071608
TITLE	Development of Stimulation Methods		
CONTRACTOR(S)	Rocket Engineering, Terra Tek		
RELATED PROJECTS	2-1-3 Liquid Explosive 2-1-4 Downward Hydrofracture 2-1-5 Stimulation Studies		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
			√		
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		371										371
2. DGE Planned:			700	2250	2500	1000	1000	1000	400	300		9150
3. Additional:												
Total:		371	700	2250	2500	1000	1000	1000	400	300		9521
Discounted Total of Planned and Additional:				7672								

EXPECTED YEAR OF COMMERCIALIZATION	1987
EXPECTED DEGREE OF SUCCESS	0.8

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	465.0
	PESSIMISTIC	176.3
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	51.2
	PESSIMISTIC	19.4
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	48.5
	PESSIMISTIC	18.4

SEE ATTACHED PAGES FOR RATIONALE

2.1 Subelements and Projects

In this analysis two subelements are analyzed together because they have interactive effects on the well stimulation process. In addition, an interaction with a third subelement, 2-1-C, Rock Mechanics, is dealt with here. The three subelements and their projects are:

Subelement and Projects:

2-1-A Well Stimulation Analysis and Modeling

2-1-1 Stimulation Review

2-1-2 Well Stimulation Review

2-1-B Development of Stimulation Methods

2-1-3 Liquid Explosive

2-1-4 Downward Hydrofracturing

2-1-5 Stimulation Studies

2-1-C Rock Mechanics

2-1-6 National Committee on Rock Mechanics

2-1-7 Rock Mechanics

2.2 Goal

The goal of these subelements is to develop less expensive and more effective stimulation methods for geothermal reservoirs. This will be accomplished by analyzing how to extend state-of-the-art methods to geothermal conditions (Subelement 2-1-A). This will be followed by developing new specialized hardware and methods suitable for use at geothermal reservoirs, and by conducting field experiments (Subelement 2-1-B). Rock mechanics R&D (Subelement 2-1-C) contributes to the analytic development of stimulation techniques.

2-1-A STIMULATION STUDY

2-1-B DEVELOPMENT OF STIMULATION METHODS

2-1-C ROCK MECHANICS

**RESERVOIR STIMULATION TECHNOLOGY PROJECTS
AND SUBELEMENTS**

2.3 Costs

Costs for Subelements 2-1-A and 2-1-B are shown here. Costs for Subelement 2-1-C are shown in section 3.0.

Costs for Subelement 2-1-A

PROJECT CODE	COST (\$1000) BY FISCAL YEARS										TOTAL 78	TOTAL
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	783		
2-1-1	34	0	34	150	0	0	0	0	0	0	150	184
2-1-2	0	15	15	0	0	0	0	0	0	0	0	15
TOTAL \$78	34 41	15 17	49 58	150 150	0 0	0 0	0 0	0 0	0 0	0 0	150 150	199 208

Costs for Subelement 2-1-B

PROJECT CODE	COST (\$1000) BY FISCAL YEARS											
	PRIOR 77	77	TTL	78	79	80	81	82	83	783	TOTAL 78	TOTAL
2-1-3	18	207	225	200	300	1000	0	0	0	0	1500	1725
2-1-4	12	134	146	150	200	0	0	0	0	0	350	496
2-1-5	0	0	0	350	1750	1500	1000	1000	1000	700	7300	7300
TOTAL \$78	30 36	341 375	371 411	700 700	2250 2045	2500 2066	1000 751	1000 683	1000 621	700 395	9150 7261	9521 7672

2.4 Identification of Impacted Parameters

The objective of Subelements 2-1-A and 2-1-B 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 well stimulation would be to reduce the number of production wells required for a given quantity of geothermal fluid. Well stimulation can also reduce the number of injection wells needed for disposing of a given quantity of spent brine.

In terms of the cost, well stimulation will increase the average capital cost of a production/injection well. The basic cost of a geothermal well, as calculated by the well cost model, does not include the well stimulation cost because the stimulation of wells is not necessary in all cases. Therefore, the basic average well cost has to be increased to account for the cost of stimulating a certain proportion of production and injection wells.

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.

2.5 Impacts on System Parameters

Subelements 2-1-A and 2-1-B are considered together in this analysis of the impacts on system parameters. This was done to minimize and possibly eliminate double counting of benefits from these subelements, which are both required to achieve common impacts on stimulation techniques and economic benefits from the applications of those techniques.

The projects in these two subelements are aimed at increasing the average productivity of the production wells by minimizing the number of dry and low production wells through geothermal well and reservoir stimulation. Due to a lack of practical experience in geothermal well stimulation, it is not possible to estimate the expected benefits for these subelements 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 stimulations 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.

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

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

To estimate 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 $= 77.5 / 100 = 0.775$ units 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 $(.33)(.33)(15) + (.33)2(15)(.5) = 2.45$ 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 $79.95/104.5 = 0.765$ 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 $(.66)(.50)(15) + (.66)(.50)(15)(.5) = 7.43$ units of additional flow. The cost is calculated in the same manner as in Scenario 2 except the percentage of nominal well cost are changed from 30% and 10% to 28% and 9%, respectively. Thus the cost is $(15)(.5)(.28) + (15)(.5)(.09) + (15)(.09) = 4.13$ 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 $(1.0)(.66)(15) + (1.0)(.66)(15)(.5) = 14.85$ 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.

It is estimated that for every percent in overall reduction of well costs a savings of \$47 million is realized. Therefore the benefit of the federal R&D program in this area would have a benefit of \$235 million (pessimistic) to \$620 million (optimistic).

2.6 Degree of Success

It is unlikely that all the non-producing (dry) and low producing wells will be stimulated to increase their productivity. Some of these wells are utilized as injection wells. There is some uncertainty about the availability of skilled personnel and equipment for stimulating all the dry and low producing wells. Therefore, an estimate of 0.80 as the degree of success of this project seems to be reasonable.

2.7 Distribution of Benefit to Subelements

The expected benefit from all aspects of well stimulation is the calculated benefit times the degree of success, or $235 \times 0.8 = \$188$ million (pessimistic) to $620 \times 0.8 = \$496$ million. This benefit has to be distributed among Subelements 2-1-A, 2-1-B, and 2-1-C because all of these subelements contribute to these R&D im-

pacts and benefits. The distribution is as follows.

As depicted in Section 2.1, above, Subelements 2-1-A (Well Stimulation Analysis and Modelling) and 2-1-C (Rock Mechanics) are conceptualized as analytic work that precedes the development and demonstration of practical methods to be carried out in Subelement 2-1-B (Stimulation Methods). It is assumed here that the development and demonstration of methods on a practical basis is much more important for delivering the benefit than are analytical studies. Accordingly, 75% of the expected benefit calculated above is attributed to Subelement 2-1-B, resulting in an expected benefit of \$141 million (pessimistic) to \$372 million (optimistic). The remaining 25% of the expected benefit is divided evenly between Subelements 2-1-A and 2-1-C, resulting in an expected benefit of \$23.5 million (pessimistic) to \$62 million (optimistic) for each of these subelements. The benefits for Subelement 2-1-C (Rock Mechanics) are carried forward to Section 3.0 below. The remaining benefits are incorporated into the results in this section.

2.8 Results

2.8.1 Subelement 2-1-A (Well Stimulation Analysis and Modelling)

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$10 ⁶) (1978 \$)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL COSTS PLANNED + SUNK
OPTIMISTIC	77.5	413.0	298.1
PESSIMISTIC	29.4	156.7	113.0

2.8.2 Subelement 2-1-B (Development of Stimulation Methods)

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$106) (1978 \$)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL COSTS PLANNED + SUNK
OPTIMISTIC	465.0	51.2	48.5
PESSIMISTIC	176.3	19.4	18.4

3.0 SUBELEMENT 2-1-C

ROCK MECHANICS

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-1-C	CONTRACT NUMBER(S)	C10002*378001 C071608*311004
TITLE	Rock Mechanics		
CONTRACTOR(S)	NAS/NRC Terra Tek		
RELATED PROJECTS	2-1-6 National Committee on Rock Mechanics 2-1-7 Rock Mechanics		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
	☒				
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	196										196
2. DGE Planned:		320	680	530	590	30	30	30	30		2240
3. Additional:											0
Total:	196	320	680	530	590	30	30	30	30		2436
Discounted Total of Planned and Additional: 2107											

EXPECTED YEAR OF COMMERCIALIZATION	FY1987
EXPECTED DEGREE OF SUCCESS	0.8

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	77.5
	PESSIMISTIC	29.4
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	32.8
	PESSIMISTIC	12.4
HISTORICAL FIGURE OF MERIT (W/ SUNK COSTS)	OPTIMISTIC	29.4
	PESSIMISTIC	11.2

SEE ATTACHED PAGES FOR RATIONALE

3.1 Projects in Subelement

Project Code

Project Title

2-1-4

National Committee on Rock
Mechanics

2-1-5

Rock Mechanics

3.2 Goal

The goal of this subelement is to gain a better understanding of rock mechanics so that more effective stimulation and drilling techniques can be developed.

3.3 Costs

COST (\$1000) BY FISCAL YEARS												
PROJECT CODE	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	Total 78+	TOTAL
2-1-4	0	15	15	30	30	30	30	30	30	60	240	255
2-1-5	0	181	181	290	650	500	560	0	0	0	2000	2181
TOTAL	0	196	196	320	680	530	590	30	30	60	2240	2436
\$78	0	216	216	320	618	438	433	20	19	43	1891	2107

3.4 Identification of Impacted Parameters

The geothermal power system parameters impacted by this program

are confined to the well cost reduction and other cost effective measures which could result from a better understanding of rock mechanics. This understanding should enable developers to drill wells at higher speed and lower cost. The fracture characteristics of the rocks in the geothermal region are an important consideration in geothermal well stimulation and also in designing hot dry rock systems.

3.5 Impacts on System Parameters

This is most easily construed as theoretical R&D which can contribute to applied R&D in the areas of well stimulation methods and improved drilling equipment. Thus the ultimate benefit of this is derived through its impacts on well stimulation R&D (Subelements 2-1-A and 2-1-B) and drilling R&D, particularly in the area of drill bit design.

As noted in the detailed analysis of Subelements 2-1-A and 2-1-B, this subelement is credited with 1/8 of the benefit derived from well stimulation R&D, a range of \$23.5 - \$62.0 million.

Any impacts on drilling R&D would require that information derived from this subelement would be incorporated into subsequent work on improved drill bits. Since DGE R&D on drill bits is for the most part nearing the commercialization stage, it seems likely that information derived from rock mechanics studies will be available too late for this to impact on new bit designs. Therefore, this subelement is given no credit for impacts on reducing drilling costs.

3.6 Degree of Success

The purpose of the subelement is to gain a better understanding of rock mechanics. Since this is more than a fact finding and reporting effort there is every indication that some problems may impede gaining of knowledge in a timely manner. Therefore the degree of success is estimated to be 0.8.

3.7 Results

TYPE OF ESTIMATE	CUMMULATIVE BENEFITS (\$10 ⁶) (1978 \$)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL COSTS PLANNED + SUNK
OPTIMISTIC	77.5	32.8	29.4
PESSIMISTIC	29.4	12.4	11.2

4.0 SUBELEMENT 2-2-A:
TWO PHASE FLOW

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-2-A	CONTRACT NUMBER(S)	S022729
TITLE	Two Phase Flow		
CONTRACTOR(S)	Denver Research Institute		
RELATED PROJECTS	2-2-1 Two Phase Flow		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		409										409
2. DGE Planned:			200	170	300	300	0	0	0	0		970
3. Additional:												0
Total:		409	200	170	300	300	0	0	0	0		1379

Discounted Total of Planned and Additional: 828

EXPECTED YEAR OF COMMERCIALIZATION	FY1983
EXPECTED DEGREE OF SUCCESS	0.5

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	76.4
	PESSIMISTIC	3.4
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	46.1
	PESSIMISTIC	2.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	29.8
	PESSIMISTIC	1.3

SEE ATTACHED PAGES FOR RATIONALE

4.1 Projects in Subelement

Project Code

2-1-1

Project Title

Two Phase Flow Studies

4.2 Goal

The goal of this subelement is to develop the capability to predict accurately both the geofluid flow rate and the well bore pressure drop of self-flowing wells under specified reservoir conditions, to optimize both field development strategy and well casing size selection.

4.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEARS											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-1-1	0	409	409	200	170	300	300	0	0	0	970	1379
TOTAL	0	409	409	200	170	300	300	0	0	0	970	1379
\$78	0	450	450	200	155	248	225	0	0	0	828	1278

4.4 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 subelement 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 drilling and completion costs. Thus the two system parameters likely to be affected by this subelement are:

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

4.5 Impacts on System Parameters

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 4-1). Figure 4-1 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. 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

¹ Michihiro 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.

FIGURE 4-1
CHARACTERISTICS OF THE FLOW RATE AT OTAKE
(AFTER FUKUDA, ET AL.¹)

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:

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

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

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 a 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 simplified model of two-phase well flow without slippage was examined by Elliott³, who defined the specific availability for the model by:

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

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

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

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 4-2. The well drilling and completion costs of a well vary with well diameter in the

FIGURE 4-2
VARIATION OF WELL COST AND AVAILABILITY
AS FUNCTIONS OF WELL DIAMETER

TABLE 4-1
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 equip.	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	3 300	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.

manner shown by curve 2 of Figure 4-2 and Table 4-1.⁴ Curve 1 is only an assumption and, therefore, has no base value. The resultant 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 the geothermal industry by increasing well availability. How much the increase will be, is difficult to estimate at this stage. However, for the purpose of this analysis 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%. For the pessimistic case, it is assumed that the number of wells will decrease by only 10%.

IMPACTED PARAMETERS	ESTIMATED IMPACTS	
	PESSIMISTIC	OPTIMISTIC
1. Number of Production Wells	-10.0%	-20.0%
2. Average Cost Per Production Wells	+10 %	+10%

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

These impacts apply only to geothermal prospects where fluid is flashed to steam. There will be no impact of this subelement at binary plants.

4.6 Degree of Success

The goal of this subelement is to develop a model for stimulating the two phase flow. The initial phase requires the collection of data, but in the final stages, the output of the model will be utilized for designing wells for optimal two phase flow. Since, (i) the suitability of two phase flow is not confirmed in all development sites, and (ii) the additional well cost might discourage some developers from designing wells for two phase flow, the degree of success of this subelement cannot be expected to exceed 0.50.

4.7 Results

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$10 ⁶) (1978 \$)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL COSTS PLANNED + SUNK
OPTIMISTIC	76.4	46.14	29.89
PESSIMISTIC	3.4	2.05	1.33

5.0 SUBELEMENT 2-2-B:

GAS LIFT TECHNOLOGY

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-2-B	CONTRACT NUMBER(S)
TITLE	Gas Lift	
CONTRACTOR(S)	Rogers Engineering	
RELATED PROJECTS	2-2-2 Gas Lift Technology	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	0										0
2. DGE Planned:		200	350	0	0	0	0	0	0		550
3. Additional:											0
Total:	0	200	350	0	0	0	0	0	0		550
Discounted Total of Planned and Additional: 518											

EXPECTED YEAR OF COMMERCIALIZATION	FY1981
EXPECTED DEGREE OF SUCCESS	0.50

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	31.5
	PESSIMISTIC	0.0
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	30.4
	PESSIMISTIC	0.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	30.4
	PESSIMISTIC	0.0

SEE ATTACHED PAGES FOR RATIONALE

5.1 Project in Subelement

Project Code

Project Title

2-2-2

Gas Lift Technology

5.2 Goal

A high well flow rate through suppression of scaling, lower O&M costs, and longer well life is the goal of this subelement.

5.3 Costs

COST (\$1000) BY FISCAL YEAR												
PROJECT CODE	PRIOR 77	77	TOTAL	78	79	80	81	82	83	83	TOTAL 78	TOTAL
2-2-2	0	0	0	200	350	0	0	0	0	0	550	550
TOTAL	0	0	0	200	350	0	0	0	0	0	550	550
\$78	0	0	0	200	318	0	0	0	0	0	518	518

5.4 Identification of Impacted Parameters

The objective of this subelement 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 like
3. Production well capital cost.

5.5 Impacts on System Parameters

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 5-1 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

TABLE 5-1

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)
Chili	
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)

fluid is high, the separation of CO_2 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 CO_2 partial 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.

5.5.1 Energy Required for CO_2 Compression

Water temperature 350° (180°C) (assumed)

Saturation pressure 136 psi (9.25 atm.)

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 to ((136 + 15) psia + 500 feet of water) or from 151 psia to $151 + 200 = 351$ psia. The minimum compression work is:

$$W = -RT \text{ hr } \frac{351}{151} \text{ (isothermal)} = -1.987 \times (460 + 350) \text{ hr } \frac{351}{151}$$

$$= -1358 \text{ Btu/lb-mole}$$

The minus sign indicates that energy must be supplied to the CO₂. It can be assumed that the brine flow rate per well is about 100,000 lbs/hr (the injection of CO₂ might reduce the well flow rate as compared to the natural flow case). If 1% by weight, i.e., 1,000 lbs/hr, of CO₂ is circulated, the energy required is $1358 \times 1000/44 = 31,000 \text{ Btu/hr} = 0.009 \text{ MW}_e = 12 \text{ HP}$ (negligible).

5.5.2 Equipment Cost

The compressor cost, 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 expensive equipment for injection, is a 5% increase in well cost.

5.5.3 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).

5.5.4 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.

IMPACTED PARAMETERS	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Production Well O&M Cost (Low salinity)	-10.0%	- 5.0%
Production Well O&M Cost (High salinity)	-30.0%	-25.0%
2. Production Well Life	+30.0%	+20.0%
3. Production Well Cost	+ 5.0%	+12.5%

5.6 Degree of Success

The technology being developed in this subelement is still in exploratory development with many problems which must be identified and addressed. Therefore, the degree of success for this subelement is assumed to be 0.5.

5.7 Results

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$10 ⁶) (1978 \$)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL COSTS PLANNED + SUNK
OPTIMISTIC	31.5	30.4	30.4
PESSIMISTIC ¹	0.0	0.0	0.0

¹ The 12.5% increase in production well capital cost outweighs all of the positive impacts in the pessimistic case.

6.0 SUBELEMENT 2-2-C:

DOWNHOLE PUMPS

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-2-C	CONTRACT NUMBER(S)	C022838 C031307
TITLE Downhole Pump			
CONTRACTOR(S) SRC, Lear			
RELATED PROJECTS 2-2-3 Thermal Downwell Pump 2-2-4 Electrical Downhole Pump			

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
			✓	✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		1359										1359
2. DGE Planned:			500									500
3. Additional:				500	1000	1000						2500
Total:		1359	500	500	1000	1000						4359

Discounted Total of Planned and Additional: \$2,532K

Discounted Total of Planned and Additional: \$2,532K

EXPECTED YEAR OF COMMERCIALIZATION	FY 1983
EXPECTED DEGREE OF SUCCESS	0.90

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	153.8
	PESSIMISTIC	62.7
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	54.7
	PESSIMISTIC	22.3
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	33.5
	PESSIMISTIC	13.7

SEE ATTACHED PAGES FOR RATIONALE

6.1 Projects In Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-2-3	Thermal Downwell Pump (Sperry)
2-2-4	Electrical Downhole Pump

6.2 Goal

The goal of this subelement is to develop and test various types of downhole pumps for utilization in geothermal wells.

6.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR										
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	> 83	TOTAL 78 →
2-2-3	922	336	1258	500	500	500	500				2000
2-2-4	12	89	101	0	0	500	500				1000
TOTAL	934	425	1359	500	500	1000	1000				3000
(\$78)	1130	468	1598	500	455	826	751				2532

The funds for FY 1978 and following years are based on the assumption that about \$2.0 million of the funds obligated to the Sperry Wellhead Generator project (see Subelement 2-6-B) will be used to develop the technology needed for a binary-system downhole-exchanger pump, and that about \$1.0 million could be devoted to continued development of an electric downhole pump, starting in FY 1980.

6.4 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.

6.5 Impacts On System Parameters

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 wellhead, and is used in a shallow well. Some tests of electric line shaft 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 applicable in U.S., the O&M cost would be high and considerable losses would be incurred due to the down-time associated with frequent maintenance requirements.

The main impacts are (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 each producing geothermal field will contain 20% reserve wells as back-up wells, it is reasonable to assume that half of the back-up wells are needed for reasons of downhole pump maintenance. If pumps are made more reliable through R&D, the number of reserve wells needed for pump maintenance might be cut in half, and thus, the overall number of reserve wells reduced to 15% of the number needed continuously to provide the fluid for operating the power plant. This change would bring about a reduction of $\frac{1.20 - 1.15}{1.20} = 4.2\%$

in the number of production wells. It is reasonable to conclude that the reduction in the number of wells (at binary plants) 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 overall reduction in the O&M costs of downwell pumps is estimated to be between 30 percent and 45 percent of the present O&M costs.

IMPACTED PARAMETERS	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Number of Production Wells	-5.0%	-3.0%
2. Downhole Pump O&M Costs	-45.0%	-30.0%

6.6 Degree Of Success

Since most all of the problems have been identified and are being solved, the degree of success for this subelement is assumed to be 0.9.

6.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	153.8	54.7	33.5
PESSIMISTIC	62.7	22.3	13.7

7.0 SUBELEMENT 2-3-A:
WORKING FLUID PROPERTIES

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-3-A	CONTRACT NUMBER(S)	S055249
TITLE	Working Fluid Properties		
CONTRACTOR(S)	National Bureau of Standards, Oklahomha University		
RELATED PROJECTS	2-3-1 Properties of Working Fluids 2-3-3 Binary Cycles Fluid Properties		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
	/	/			✓
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		143										143
2. DGE Planned:			170	170	100	0	0	0	0	0		440
3. Additional:												0
Total:												583
Discounted Total of Planned and Additional: 407												

EXPECTED YEAR OF COMMERCIALIZATION	FY 1982
EXPECTED DEGREE OF SUCCESS	1.00

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	1.3
	PESSIMISTIC	0.0
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	3.19
	PESSIMISTIC	0.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	1.96
	PESSIMISTIC	0.0

SEE ATTACHED PAGES FOR RATIONALE

7.1 Projects In Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-3-1	Properties of Working Fluids
2-3-3	Binary Cycles

7.2 Goal

This subelement deals with basic research looking for increased knowledge of working fluid properties leading to the design of economical and efficient direct contact heat exchangers. This work may find its way into the source book to be developed by Subelement 2-5-B.

7.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR									
	PRIOR 77	77	TOTAL	78	81	82	83	>83	TOTAL 78 →	TOTAL
2-3-1	0	0	0	70	70	100	0	0	240	240
2-3-2	0	143	143	100	100	0	0	0	200	343
TOTAL	0	143	143	170	170	100	0	0	440	583
(\$78)	0	157	157	170	154	83	0	0	407	664

7.4 Identification Of Impacted Parameters

The successful completion of this subelement may result in the design of a more efficient energy conversion cycle. The design of a more efficient cycle will reduce the requirement of geothermal fluid. Thus, the number of production wells will be reduced.

7.5 Impacts On System Parameters

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, and no great surprises are expected. Therefore, the information generated by this subelement will probably not have large impacts on plant designs.

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, but the reduction is likely to be very small. Therefore, the following estimates of the primary benefit appears to be reasonable.

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Number Of Production Wells*	-0.2%	0.0%

7.6 Degree Of Success

The subelement is assigned a degree of success of 1.0 since the projects are basic research, finding and reporting results of tests of working fluid properties, and no surprises are expected.

7.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	1.3	3.19	1.9
PESSIMISTIC	0.0	0.0	0.0

* There could be some reduction in the number of injection wells also. However, the magnitude of this reduction is likely to be insignificant.

8.0 SUBELEMENT 2-3-B:
HEAT EXCHANGE AND BINARY FLUID

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-3-B	CONTRACT NUMBER(S) 05ENG48
TITLE Heat Exchange and Binary Fluid	
CONTRACTOR(S) LBL	
RELATED PROJECTS 2-3-2 Heat Exchange Technology and Binary Fluid Experiment	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			✓
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		1154										1154
2. DGE Planned:			575	400	0	0	0	0	0	0		975
3. Additional:												0
Total:		1154	575	400	0	0	0	0	0	0		2129
Discounted Total of Planned and Additional: 939												

EXPECTED YEAR OF COMMERCIALIZATION FY 1982
EXPECTED DEGREE OF SUCCESS 1.00

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	11.6
	PESSIMISTIC	4.3
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	12.4
	PESSIMISTIC	4.6
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	5.2
	PESSIMISTIC	2.0

SEE ATTACHED PAGES FOR RATIONALE

8.1 Projects In Subelement

8.2 Goal

The goal of this subelement is to study heat exchange properties of binary fluids with the objective of improving the design of binary energy conversion plants.

8.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR										
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	TOTAL 78→	TOTAL
2-3-2	381	773	1154	575	400	0	0	0	0	975	2129
TOTAL	381	773	1154	575	400	0	0	0	0	975	2129
(\$78)	461	850	1311	575	364	0	0	0	0	939	2250

8.4 Identification Of Impacted Parameters

The main objective of this subelement is to study the heat transfer process and provide data which will enable plant designers to design more efficient and less expensive heat exchangers for binary systems. Although the output of this subelement may eventually

be used for improving the design of indirect heat exchange condensers, the main emphasis of this subelement is on reducing the cost of primary shell and tube heat exchangers. Therefore, the cost of the primary heat exchanger is the system parameter impacted by this subelement.

8.5 Impacts On System Parameters

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

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

where Q is the heat transfer load, ΔT 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,

$$\frac{1}{U} = \frac{1}{h_{w.f.}} + \frac{1}{h_{g.g.}} + F_{w.f.} + F_{g.f.}$$

where $h_{w.f.}$ is the heat transfer coefficient for working fluid (with no fouling), $h_{g.g.}$ is the heat transfer coefficient for the geothermal fluid (with no fouling), $F_{w.f.}$ is the fouling factor for the working fluid and $F_{g.g.}$ is the fouling factor for the geothermal fluid.

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

$$\begin{aligned}\frac{1}{U} &= \frac{1}{300} + \frac{1}{1500} \times 1.15 + 0.005 + 0.002 \times 1.15 \\ &= \frac{1}{300} + 0.03567 \\ \text{or } U &= 145 \text{ Btu/hr. ft}^2\text{ }^{\circ}\text{F}\end{aligned}$$

If the lack of better data concerning working fluid properties causes the designers to underestimate the value of $h_{w.f.}$ by 30% (assumption), the availability of more reliable data will result in the utilization of a higher value of $h_{w.f.}$ (the value will be 390 instead of 300). The resultant value of U will be given by:

$$U = \frac{1}{\frac{1}{390} + 0.003567} = 163 \text{ Btu/hr. ft}^2\text{ }^{\circ}\text{F}$$

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

$$\frac{163 - 145}{145} \text{ or } 12.5\%$$

Since nearly 70% of the heat exchanger cost is directly proportional to the area of heat transfer, the reduction in the capital cost of the heat exchanger will be:

$$12 \times 0.70 = 8.4\%$$

A more conservative estimate of the impact could result in a lower value. However, it is reasonable to estimate that the results of this research will reduce the cost of primary heat exchangers between 3% and 8%. There could be a small impact on the O&M cost, but it will be insignificant in comparison with the change in the capital cost.

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
Capital Cost of Primary Heat Exchanger	-8.0%	-3.0%

8.6 Degree of Success

The project in the subelement deals in basic and exploratory research with no chance of failure since its results are just reporting on observations. The range of possible technical success and impact of R&D is accounted for in the estimate of potential impact, above. Therefore the degree of success is set at 1.0.

8.7. Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
PESSIMISTIC	4.3	4.58	1.91
OPTIMISTIC	11.6	12.35	5.16

9.0 SUBELEMENT 2-3-C:
BINARY DIRECT CONTACT HEAT EXCHANGE

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-3-C	CONTRACT NUMBER(S)	C071735 05ENG48 C031076 S071549 C031116 S071523 C054893
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TITLE Binary Direct Contact Heat Exchange

CONTRACTOR(S) INEL, U of Utah, LBL, Ben Holt, DSS Engineers

RELATED PROJECTS 2-3-4 Direct Contact Research, 2-3-5 Direct Contact Heat Exchanger Power Cycle, 2-3-7 2nd. Gen. Heat Exchanger, 2-3-8 Direct Heat Exchanger, 2-3-9 Direct Contact Heat Exchanger (Binary), 2-3-6 Direct Contact Heat Exchange for Geothermal Brine, 2-3-10 Study & Test Direct Contact Heat Exchanger 2-3-11 2nd Generation Direct Contact Heat Exchanger

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)

	✓	✓	✓	✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)

	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	2006											2006
2. DGE Planned:			1100	1800	0							2900
3. Additional:												0
Total:	2006	1100	1800	0								4906

Discounted Total of Planned and Additional: 2736

EXPECTED YEAR OF COMMERCIALIZATION FY 1982

EXPECTED DEGREE OF SUCCESS 0.60

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	404.8
	PESSIMISTIC	217.2
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	88.77
	PESSIMISTIC	47.63
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	60.81
	PESSIMISTIC	32.63

SEE ATTACHED PAGES FOR RATIONALE

9.1 Projects In Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-3-4	Direct Contact Research
2-3-5	Direct Contact Heat Exchanger Power Cycle
2-3-6	Direct Contact Heat Exchange for Geothermal Brine
2-3-7	2nd Generation Heat Exchanger
2-3-8	Direct Heat Exchanger
2-3-9	Direct Contact Heat Exchanger (Binary)
2-3-10	Study And Test Direct Contact Heat Exchanger
2-3-11	2nd Generation Direct Contact Heat Exchanger

9.2 Goal

The goal of this subelement is to develop a reliable, efficient and economical direct contact heat exchanger for use with binary systems.

9.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR										TOTAL 78 →	TOTAL
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83		
2-3-4	633	300	933	0	0						0	933
2-3-5	167	0	167	0	0						0	167
2-3-6	87	34	121	0	0						0	121
2-3-7	108	0	108	0	0						0	108
2-3-8	0	142	142	0	0						0	142
2-3-9	128	0	128	0	0						0	128
2-3-10	251	156	407	50	0						50	457
2-3-11	0	0	0	1050	1800	0					2850	2850
TOTAL	1374	632	2006	1100	1800						2900	4906
(\$78)	1663	695	2378	1100	1636						2736	3994

9.4 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 mechanical cost item in the GEOBEN cost model. 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 will be impacted by this subelement:

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

A direct contact heat exchange system involves a 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 higher).

EG&G of Idaho Falls has conducted a conceptual study of a direct contact 50 MW_e plant. The contractor who did the cost estimate for this was Ford, Bacon, and Davis Utah, (1). Mr. Gary Stuart of EG&G indicated that the fixed cost for a 50 MW_e (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\$)

COST ITEM	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:

$$\left(\frac{70.4 - 73.3}{73.3} \right) \times 100 = -4.0\%$$

(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 5.0%.

The plant O&M costs of a direct contact system are assumed to be 20% lower than those for the shell and tube system. However, a penalty amounting to 10 percent 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.

IMPACTED PARAMETER	ESTIMATED IMPACT	
	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 Capital Cost	- 5.0%	- 2.0%
5. General Plant O&M Cost	-10.0%	- 5.0%

Reference:

1. Harris, J. S., Steward, G. G. and Rogers, V. C. "Conceptual Design and Evaluation of Geothermal-Driven 50 MW Power Plants." FB&DU Job No. UC-191. Salt Lake City, Utah: Ford, Bacon and Davis Utah, Inc., 1977.

9.6 Degree Of Success

This subelement has a number of significant problems such as separation of fluids and scale-up problems which remain unresolved. Therefore, a degree of success of 0.6 is assumed.

9.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	404.8	88.77	60.81
PESSIMISTIC	217.2	47.63	32.63

10.0 SUBELEMENT 2-3-D:

BINARY SHELL AND TUBE HEAT EXCHANGE

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-3-D	CONTRACT NUMBER(S) C071375 C031076
TITLE Binary S/T Heat Exchange	
CONTRACTOR(S) INEL, Aerojet Energy Conversion Co.	
RELATED PROJECTS 2-3-12 Liquid Fluidized Bed Heat Exchanger 2-3-13 Advanced Geothermal Primary Heat Exchanger	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓	✓	✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		277										277
2. DGE Planned:			695	1100	800	400						2995
3. Additional:												0
Total:		277	695	1100	800	400						3272

Discounted Total of Planned and Additional: 2656

EXPECTED YEAR OF COMMERCIALIZATION FY 1983
EXPECTED DEGREE OF SUCCESS 0.60

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	11.2
	PESSIMISTIC	0.0
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	3.5
	PESSIMISTIC	0.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	3.0
	PESSIMISTIC	0.0

SEE ATTACHED PAGES FOR RATIONALE

10.1 Projects In Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-3-12	Liquid Fluidized Bed Heat Exchanger
2-3-13	Advanced Geothermal Primary Heat Exchanger

10.2 Goal

A more reliable, efficient and economical shell and tube heat exchanger for geothermal applications is the goal of this subelement.

10.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR										
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →
2-3-12	0	0	0	195	400	400	0				995
2-3-13	24	253	277	300	100	400	400	0			1200
TOTAL	24	253	277	495	500	800	400	0			2195
(\$78)	29	278	307	495	455	661	301	0			1912

10.4 Identification Of Impacted Parameters

Both the projects in this subelement are aimed at the development of less expensive and more reliable shell and tube (indirect)

heat exchangers. The successful completion of this subelement will impact the following system parameters:

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

10.5 Impacts On System Parameters

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.

The size of the impacts is calculated as follows. Assuming that the brine side fouling factor for a conventional heat exchanger is 0.003, then:

$$\frac{1}{U} = \frac{1}{300} + \frac{1.15}{1500} + 0.0005 + 0.003 \times 1.15,$$

following the calculations in Section 8.5, above, where U is the overall heat transfer coefficient. U is then equal to 124.2 Btu/hr.ft² °F. From an estimate made by Aerojet Energy Conversion Company (1), the solid contents in the brine could reduce the brine side fouling factor to 0.0005. Then U would be equal to 193.2 (same units).

The heat transfer area is accordingly reduced by:

$$\frac{193.2 - 124.2}{193.2} = 35.7\%.$$

If a size versus cost exponent of 0.6 is assumed for the heat exchanger, the new cost becomes:

$$\text{COST}_{\text{NEW}} = \text{COST}_{\text{OLD}} \cdot \left(\frac{U_{\text{OLD}}}{U_{\text{NEW}}} \right)^{0.6} = 0.767 \times \text{COST}_{\text{OLD}}.$$

Hence a cost reduction of 23.3% results. The actual cost reduction will be less than 23.3% because the fluidized bed heat exchanger would require additional equipment, such as centrifuge, slurry pump, and makeup systems. However, the cost of these additional components is very small compared to the heat exchanger cost, and therefore is neglected.

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

	<u>O&M ANNUAL COSTS (1976\$)</u>	
	<u>CONVENTIONAL</u>	<u>APEX</u>
Cleaning costs	\$29,000	\$ 0
Cost due to ΔP 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).

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Capital Cost of Heat Exchanger	- 23%	- 10%
2. O&M Cost of Heat Exchanger	+160%	+200%

10.6 Degree of Success

Since the heat exchanger developed in this subelement is a new form of heat exchanger which has not been tried in other industries, the degree of success is assumed to be 0.6.

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

10.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	11.2	3.5	3.0
PESSIMISTIC	0.0	0.0	0.0

11.0 SUBELEMENT 2-3-E:

BASIC HEAT EXCHANGE

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-3-E	CONTRACT NUMBER(S)	
TITLE	Basic Heat Exchange		
CONTRACTOR(S)	EPRI		
RELATED PROJECTS	2-3-14 Heat Exchange Test Tech Base Coop		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
				✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		350										350
2. DGE Planned:			200									200
3. Additional:												
Total:		350	200									550
Discounted Total of Planned and Additional:		200										

EXPECTED YEAR OF COMMERCIALIZATION	FY 1981
EXPECTED DEGREE OF SUCCESS	1.0

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	2.2
	PESSIMISTIC	1.8
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	3.0
	PESSIMISTIC	2.4
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	3.0
	PESSIMISTIC	2.4

SEE ATTACHED PAGES FOR RATIONALE

11.1 Projects In Subelement

PROJECT CODE

PROJECT TITLE

2-3-14

Heat Exchange Test Tech Base Coop

11.2 Goal

The goal of this subelement is to demonstrate the technical and operational soundness of the large scale shell and tube heat exchangers for binary energy conversion systems.

11.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR										
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →
2-3-14	0	0	0	200	600	0	0				800
TOTAL	0	0	0	200	600	0	0				800
(\$78)	0	0	0	200	545	0	0				745

11.4 Identification Of Impacted Parameters

The activities associated with this subelement involve demonstrating the reliability of large-scale shell and tube heat exchangers for use in binary energy conversion systems. The knowledge gained as the results of these activities would help design engineers to avoid over-design and would reduce the O&M cost of heat exchange systems.

It is noted that the knowledge on heat exchanger performance and reliability can still be gained without this subelement. However, in the absence of this R&D activity, this knowledge would be realized only under actual operation and after a period of time of high O&M cost or over-designed heat exchangers built during that period of time.

11.5 Impacts On System Parameters

This subelement involves demonstrating and testing the reliability of heat exchangers of the type to be used in binary plants. The main technical impact of this activity is improved knowledge and specification of brine fouling factors. Accurate information about the fouling factors will reduce the degree to which heat exchangers must be overdesigned.

The subelement involves demonstrating and testing the reliability and performance of heat exchangers. The main impacts can be identified as capital cost and O&M cost savings in binary geothermal power plants. These savings are due to the knowledge that would be gained as a result of this subelement.

If this subelement is not funded the above knowledge would not be available to design engineers. The result would be over-designed power plants and high O&M costs. It is assumed that lack of funding for this subelement would cause a two year delay in the attainment of the knowledge in actual geothermal binary power plant operations. Even though the O&M costs of all binary shell and tube plants will be reduced when the above knowledge is gained, those plants built during the two year

delay will remain over-designed. Therefore, a major benefit to be had from this subelement is reduced capital costs through knowledge gained allowing economical sizing of heat exchangers and power plants.

The estimates of the benefits derived from this subelement are likely to be conservative because the cooperative program will also provide test facilities for testing other types of heat exchangers developed in other subelements. 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.

11.5.1 Capital Cost of Heat Exchangers

Let us assume that the correct design for a heat exchanger uses a value of 0.003 for the brine side fouling factor, and that an over-design used 0.005. We further assume that the information gained in this subelement reduces the overdesign by 60% (pessimistic) to 100% (optimistic).

The oversized heat exchanger has an assumed heat transfer coefficient U_1 , given by:

$$\frac{1}{U_1} = \frac{1}{300} + \frac{1.15}{1500} + 0.005 \times 1.15 + 0.0005 = \frac{1}{96.6} ,$$

calculated as explained in the analyses of previous subelements.

If the "correct" fouling factor is arrived at by this R&D subelement, the heat exchangers will be designed using heat transfer coefficient U_2 , given by:

$$\frac{1}{U_2} = \frac{1}{300} + \frac{1.15}{1500} + 0.003 \times 1.15 + 0.0005 = \frac{1}{124.2}$$

Use of the "correct" figure would allow the size of the heat exchanger to be reduced by a factor of $\frac{U_2 - U_1}{U_1} = \frac{124.2 - 96.6}{96.6}$,

or 28.6%. This is the optimistic estimate of impact.

To derive a pessimistic estimate of impact, we assume that this subelement arrives at an estimate of the brine-side fouling factor that moves only 50% toward the correct figure, and is set at 0.0038. In that case, U_2 would be estimated to be 119.0, and the design size of the heat exchanger would be reduced by $\frac{119 - 96.6}{96.6}$, or 23.2% (pessimistic impact).

The consequent capital cost reductions are calculated assuming the 0.6 power for cost/size relationships. For the optimistic case, $\frac{\text{new cost}}{\text{old cost}} = \left(\frac{1}{1.286}\right)^{0.6} = 0.860$, equivalent to a reduction in heat exchanger capital cost of 14%. For the pessimistic case, $\frac{\text{new cost}}{\text{old cost}} =$

$$\left(\frac{1}{1.232}\right)^{0.6} = 0.882, \text{ equivalent to a cost reduction of 11.8\%}.$$

11.5.2 O&M Costs

The O&M cost reduction is rather difficult to estimate because there has been no experience with the O&M of binary plant heat exchangers reported. Therefore, the reduction can only be assumed to be somewhere between 10% - 20%.

11.5.3 Inputs to GEOBEN Model

The heat exchanger capital and O&M costs each represent about 60% of the "Process Mechanical" accounts of the GEOBEN code. Scaling the impacts from Sections 11.5.2 and 11.5.3 by this factor results in the following GEOBEN input impacts.

IMPACTED PARAMETERS	Estimated Impacts	
	Optimistic	Pessimistic
1. Capital cost, process mechanical (Binary)	- 8.4%	- 7.1%
2. O&M Cost, process mechanical (Binary)	-12.0%	- 6.0%

11.5.4 Calculation of Benefits

The calculation of benefits is based on the assumption that the above impacts could be gained through either R&D or through two years of operation of the first 50 MW_e binary plant. Since the first binary plant is not projected to be in operation until 1983, in the absence of R&D the impacts would not be available until 1985. With R&D, the impacts are estimated to be available by 1981 (date of commercialization), and thus could affect both capital and O&M costs of the first binary plant(s).

The GEOBEN model was used to calculate total electricity busbar costs assuming an impact year of 1985 (non-R&D case), and assuming an impact year of 1981 (R&D case). The difference between the former and the latter is taken to be the economic benefit from this subelement.

11.6 Degree of Success

The degree of success for this subelement is 1.0 since it is providing labor and administration of test facility and is not involved with development of any hardware.

11.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	2.2	3.0	3.0
PESSIMISTIC	1.8	2.4	2.4

12.0 SUBELEMENT 2-4-A:

TOTAL FLOW

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-4-A	CONTRACT NUMBER(S)	05ENG48
TITLE Total Flow			
CONTRACTOR(S) LLL			
RELATED PROJECTS 2-4-1 Total Flow Concept			

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		5051										5051
2. DGE Planned:			1700	0								1700
3. Additional:												0
Total:		5051	1700	0								6751
Discounted Total of Planned and Additional: 1700												

EXPECTED YEAR OF COMMERCIALIZATION	FY 1981
EXPECTED DEGREE OF SUCCESS	0.03

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	207.1
	PESSIMISTIC	4.7
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	4.1
	PESSIMISTIC	0.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	0.8
	PESSIMISTIC	0.0

SEE ATTACHED PAGES FOR RATIONALE

12.1 Projects in Subelement

12.2 Goal

The goal is to determine the feasibility of expanding wet steam through a total flow turbine system. The emphasis will be on the development of systems for recovery and conversion of energy stored in hot water deposits containing more than 3 percent dissolved solids.

12.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-4-1	3719	1332	5051	1520	0						1520	6571
TOTAL	3719	1332	5051	1520	0						1520	6571
FY 78	4500	1465	5965	1520	0						1520	7485

12.4 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

FIGURE 1
COMPARISON OF POWER RECOVERY FRACTIONS
FOR VARIOUS TYPES OF CONVERSION PLANTS
(Data taken from reference 1)

NOTES TO FIGURE 1

Reservoir	
<u>Curves</u>	<u>Temperature</u>
1	150°C, SELF FLOW, PURE WATER
2	150°C, PUMPED, PURE WATER
3	300°C, FLOW SELF, PURE WATER
4	300°C, SELF FLOW, 30% BRINE WATER

ASSUMPTIONS:

Steam Processes:

Steam Condensing Temperature is 45°C

Steam Turbine Efficiency 70%

Two-Phase Expander Efficiency 60%

Pump Efficiency 70%

Atmospheric Disposal

Binary Processes:

Organic Fluid Condensing Temperature is 45°C

Organic Fluid Isobutane

Cycle Efficiency 70%

ΔT at Inlet and Outlet of Heat Exchangers 10°C (self flow)
20°C (pumped)

Water Disposal Pump Efficiency 79%

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.

12.5 Impacts on System Parameters

Thermal performance of the total flow system has been analyzed and compared with other compatible systems by Elliott (1). The results of the analysis are shown for flash steam and total flow systems in Figure 1. The vertical axis of Figure 1 indicates the ratio of the net power output to the available wellhead power. The horizontal axis indicates the number of steam-water separation stages in each system.

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:

- 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.

- 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).

From the curves 1, 3 and 4 of Figure 1, it can be seen that the increase in the utilization efficiency of the total flow system over a double-flash 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 curve 2 is not considered because it is not cost-effective value to use downhole pumps for flash-steam plants.

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), and shown in Figure 2 for the same systems of Figure 1. From Figure 2(a), the heat rejection load is:

$$\text{Heat rejection } R_T = \frac{\text{Power output}}{0.08} \text{ for total flow,}$$

$$\text{Heat rejection } R_F = \frac{\text{Power output}}{0.095} \text{ for flash steam (mean value, two-stage flash).}$$

FIGURE 2
COMPARISON OF POWER OUTPUTS PER UNIT
CONDENSER HEAT REJECTION FOR CASES
1 AND 3 OF FIGURE 1

The change for constant power output is:

$$\frac{R_T - R_F}{R_F} = \frac{\frac{1}{0.08} - \frac{1}{0.095}}{\frac{1}{0.095}} = \frac{0.015}{0.08}$$

$$= 18.75\%.$$

From Figure 2(b), the heat rejection load is:

$$R_T = \frac{\text{Power output}}{0.182}$$

$$R_F = \frac{\text{Power output}}{0.224}$$

and the change for constant power output is:

$$\frac{R_T - R_F}{R_F} = \frac{0.224 - 0.182}{0.182}$$

$$= 23.08\%.$$

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:

$$\frac{\text{Cost}_1}{\text{Cost}_2} = \frac{\text{Load}_1}{\text{Load}_2}^{0.6}.$$

Hence the cost for the condenser and heat rejection system of the total flow plan is from: $\left(\frac{1.875}{1}\right)^{0.6} = 1.109$,

$$\text{to: } \left(\frac{1.2308}{1}\right)^{0.6} = 1.133$$

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 GEOBEN 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 total 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 to be a cost reduction of, say, 10 to 20% for this component.

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 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 to estimate because the development of a two-phase turbine is still remote from even the pilot testing stage. It will be presumed that a two-phase turbine would 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 the steam turbine 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 GEOBEN 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 GEOBEN 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:

Optimistic Case:

$$\text{Turbine:} \quad : \quad 0.18 \times 60\% \quad = \quad 10.8\%$$

$$\text{Heat Rejection:} \quad 0.13 \times 10.9\% = \quad \underline{1.4\%}$$

$$\text{Total} \quad \quad \quad 12.2\%$$

Pessimistic Case:

$$\text{Turbine} \quad \quad : \quad 0.18 \times 180\% \quad = \quad 32.4\%$$

$$\text{Heat Rejection:} \quad 0.13 \times 13.3\% = \quad \underline{1.7\%}$$

$$\text{Total} \quad \quad \quad 34.1\%$$

Summary

The cost changes for a total flow system when compared with a conventional flash steam system area summarized as follows:

IMPACTED PARAMETER	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%

12.6 Degree of Success

Experimental results from this subelement have been discouraging to date. A nozzle block and aluminum turbine wheel tested under conditions of partial admission delivered a machine efficiency of 22%, which, when extrapolated to full admission, indicates a machine efficiency of 38-46% might be obtained. This is significantly lower than the 60% theoretical goal postulated for this development. It appears that meeting this goal will require several significant major technical breakthroughs, e.g., a nozzle that breaks the liquid phase into submicron sized droplets. Thus, the likelihood of technical success is deemed to be in the 0.1 range.

Furthermore, since the concept is focused on only a subset of the entire resource (brines with total dissolved solids exceeding 3%) the

concept would probably be applied at only about 30% of the envisioned flash steam plants. Therefore the degree of success is estimated to be $0.1 \times 0.3 = 0.03$.

12.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (\$10 ⁶ , 78\$)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	207.1	4.1	0.8
PESSIMISTIC	4.7	0.0	0.0

-
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.
 3. V. Thanh Nguyen and Harpal S. Dhillon, "An Analysis of the Geothermal Energy Extraction and Utilization Technology RD&D Program," MITRE/Metrek Report MTR-7886, June, 1978.

13.0 SUBELEMENT 2-4-B:

ROTARY SEPARATOR

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-4-B	CONTRACT NUMBER(S) C031228
TITLE Rotary Separator	
CONTRACTOR(S) Biphase Energy Systems	
RELATED PROJECTS 2-4-2 Geothermal Rotary Separator	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
			✓	✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	240										240
2. DGE Planned:		15	400								415
3. Additional:											0
Total:	240	15	415								655
Discounted Total of Planned and Additional: 379											

EXPECTED YEAR OF COMMERCIALIZATION FY 1982
EXPECTED DEGREE OF SUCCESS 0.60

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	282.6
	PESSIMISTIC	148.8
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	447.
	PESSIMISTIC	236.
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	260.
	PESSIMISTIC	137.

SEE ATTACHED PAGES FOR RATIONALE

13.1 Projects in the Subelement

PROJECT CODE

2-4-2

PROJECT TITLE

Geothermal Rotary Separator

13.2 Goal

The goal of this subelement is to design and test a geothermal well head rotary separator in which the energy loss will be less than that in conventional flashers.

13.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78→	TOTAL
2-4-2	77	163	240	15	400	0					415	655
TOTAL	77	163	240	15	400	0					415	655
(\$78)	93	179	272	15	364	0					379	651

13.4 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 for production wells as well as injection wells. The replacement of flash tanks and gravity separa-

tors 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.

13.5 Impact on System Parameters

The key to all estimates here is that the rotary separator, because it captures kinetic energy from the geothermal fluid that is lost in a conventional flash steam system, uses more of the available energy in the fluid. 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.

13.5.1 Production and Injection Wells

Because more energy is drawn from each unit of fluid, for a fixed plant size (50MWe), 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 useful energy increment is assumed to be only 90 percent of the ideal case, and the change in well number including the above mentioned losses, becomes:

$$0.9 \times \frac{68 \times 0.9 - 53}{68 \times 0.9}$$

which is equivalent to a 12.0 percent (pessimistic estimate) reduction in well number.

13.5.2 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.⁽¹⁾

Table 13-I shows a capital cost summary for a conceptual design for a 50MWe (net), 59.1MWe (gross) dual flash geothermal electric plant.⁽²⁾ To simplify calculations, the estimated cost of the

Table 13.1

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY
 50MWe (NET) GEOTHERMAL POWER PLANT
 HEBER, CALIFORNIA (1)

FIELD CONSTRUCTION	INSTALLED COST ⁽²⁾ (\$1000)	PERCENT OF TOTAL
Mechanical Equipment	16,590	58%
Turbine-Generator (59.1 MWe	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 \$

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 generator.

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 GEOBEN 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:

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 far the optimistic case, but using \$248/kW for the separator cost, the derived changes for the GEOBEN accounts are:

Turbine Generator (Including 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 1.6% 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. The reader should also note that more than 95% of the 9.1 MW of auxiliary powers used in the plant is used for pumping air and blowing water. A 20% reduction in mass flow through the plant could reduce this requirement by about 1.8 MW, which would allow some slight ($1.8/59.1$; equivalent to about 3%) additional scaling-down of many components in the plant. This is ignored here to ensure that the estimated impacts do not become overly optimistic. O&M costs are assumed to remain the same.

13.5.3 Summary of Impacts (Flash Steam Plants)

IMPACTED PARAMETER	ESTIMATED IMPACTS	
	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%

13.6 Degree of Success

This subelement will result in a new form of technology which has not been used before in other industries. It is, therefore, assumed to have a degree of success of 0.6.

13.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	282.6	447	260
PESSIMISTIC	148.8	236	137

REFERENCES

1. Personal communication from Mr. Lance Hays, Biphase Energy Systems, Research - Cottrell, April, 1979.
2. Bechtel Corporation, "Conceptual Design of Commercial 50 MWe (Net) Geothermal Power Plants at Heber and Niland, California", Report Number SAN-1124-1, Bechtel Corporation, San Francisco, California, October, 1976.

14.0 SUBELEMENT 2-4-C:

HELICAL SCREW EXPANDER

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-4-C	CONTRACT NUMBER(S)	A 361000
TITLE	Expander		
CONTRACTOR(S)	JPL/NASA		
RELATED PROJECTS	2-4-3 Helical Screw Expander		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
				✓	✓
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	778										778
2. DGE Planned:		430	0								430
3. Additional:											0
Total:	778	430	0								1208
Discounted Total of Planned and Additional:				430							

EXPECTED YEAR OF COMMERCIALIZATION	FY 1981
EXPECTED DEGREE OF SUCCESS	0.90

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	5.5
	PESSIMISTIC	2.3
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	11.5
	PESSIMISTIC	4.8
HISTORICAL FIGURE OF MERIT (W/ SUNK COSTS)	OPTIMISTIC	3.7
	PESSIMISTIC	1.5

SEE ATTACHED PAGES FOR RATIONALE

14.1 Projects in Subelement

PROJECT CODE

2-4-3

PROJECT TITLE

Helical Screw Expander

14.2 Goal

Development of a prime mover suitable for conversion of energy at well head, and at liquid dominated resevoirs in general.

14.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-4-3	596	182	778	430	0						430	1208
TOTAL	596	182	778	430	0						430	1208
(\$78)	721	200	921	430	0						430	1351

14.4 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. The net effect is assumed to be small additions to the capacity goals of the hydrothermal development scenario.

14.5 Analysis of Benefits

This subelement was analyzed together with other DGE projects that are developing small scale wellhead generators. The analysis is documented in Appendix B of this volume.

The results of the analysis indicate that the helical screw units being developed in this subelement could save between \$2.3 to \$5.5 million (1978 \$), compared to the cost of the cheapest alternative electricity (nuclear or coal) in the western states.

The reader should note that this subelement is given no direct credit for reducing the cost of electricity from larger (50 MWe and up) hydrothermal electric plants.

14.6 Degree of Success

The expander has gone through performance tests successfully. There is no reason to believe the system will not capture most of the small market postulated for it. Therefore the degree of success is set at 0.9.

14.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFIT (10 ⁶ \$78)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned - Sunk Costs)
OPTIMISTIC	5.5	11.5	3.7
PESSIMISTIC	2.3	4.8	1.5

15.0 SUBELEMENT 2-5-A:
OPTIMIZATION STUDIES

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-5-A	CONTRACT NUMBER(S)
TITLE Optimization		
CONTRACTOR(S) LBL (Lawrence Berkeley Laboratory)		
RELATED PROJECTS 2-5-1 Optimization Studies		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
☒	☐	☐	☐	☐	☐
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		0										0
2. DGE Planned:			250	0								250
3. Additional:												0
Total:		0	250	0								250

Discounted Total of Planned and Additional: 250

EXPECTED YEAR OF COMMERCIALIZATION ?	1981
EXPECTED DEGREE OF SUCCESS	0.60

CALCULATED BENEFIT (DISCOUNTED TO \$-MILLIONS, 1978)	OPTIMISTIC	750.
	PESSIMISTIC	400.
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	1800.
	PESSIMISTIC	960.
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	1800.
	PESSIMISTIC	960.

SEE ATTACHED PAGES FOR RATIONALE

15.1 Projects in Subelement

15.2 Goal

To develop a computer code, GEOTHM, for optimum design of binary-cycle geothermal power plants using site specific data.

15.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78	TOTAL
2-5-1	0	0	0	250	0						250	250
TOTAL	0	0	0	250	0						250	250
(\$78)	0	0	0	250	0						250	250

15.4 Identification of Impacted Parameters

The analytic tools developed by this subelement will allow power plant designers to optimize the designs of both generic and site-specific power plants for utilizing intermediate temperature resources through binary-cycle technology.

LBL has identified five areas of impact of this analysis and

modelling effort upon the development and probable costs of binary electric plants (1). These are listed here, and discussed in terms of how each impact is handled with respect to this benefit/cost analysis.

(1) The data and analytical tools from this project will reduce the uncertainty in the cost of producing electricity from intermediate-temperature liquid-dominated geothermal resources, and reduce the cost estimates for initial commercial developments, and thereby speed up the commercial exploitation of these resources. While this is an important expected end-result from this project, it is not dealt with specifically within the framework of this benefit/cost analysis, but should be evaluated in later market penetration studies.

(2) Direct-contact heat exchange, once perfected on a commercial scale, could reduce electrical energy costs by as much as 20% (LBL estimate). These effects are dealt with in the discussion of Subelements 2-3-C and 2-7-B.

(3) Data on surface heat exchange coefficients could reduce the capital cost of initial binary-cycle plants by 10% by reducing the amount of heat exchange surface by 20-25% (LBL estimate). These effects are dealt with in Subelements 2-3-B, 2-3-D, 2-3-E, and 2-7-A.

(4) Optimization of specific resource-plant combinations can yield a 10% reduction in energy cost compared to thermodynamically-optimized designs (LBL estimate). The economic effects of this

impact are examined below.

(5) Optimization of electric plant operation procedures, especially with respect to allowing the heat rejection temperature to float with ambient wet bulb temperature, could reduce the energy cost by up to 12% (2). The economic effects of this impact are examined below.

15.5 Analysis of Impacts of Benefits

The successful completion of the subelement will enable power plant designers to optimize the design of power plants for utilizing intermediate temperature resources. Although estimates of the savings in different components of the plant can be made explicitly, it is pragmatic here to estimate the effects of this subelement directly in terms of overall reduction in the cost of electricity from binary geothermal electric plants.

We note first, that for binary plants carried in the GEOBEN development scenario, each 1% reduction in the cost of electricity (bus bar price) saves \$49.5 million (1978 present value, 1978 \$, discount rate 10%), as the economic benefit.

The two technical impacts that are credited directly here are: (1) a 10% reduction in electricity cost due to optimal matching of plant design to reservoir/resource characteristics, and (2) a 12% reduction in electricity cost due to operating binary plants in a floating temperature heat rejection mode.

The LBL estimate for the first impact seems reasonable as an upper bound. However, the LBL estimate of the economic value of the floating operation mode seems to be biased toward the high side because it assumes that the extra energy can be sold at baseload rates. This is probably not the case, since this operation mode generally will not add firm capacity to a generating system, and therefore will contribute only to fuel saving, at about one-half of the value of firm baseload power. Therefore the maximum impact of this effect is halved, to about 6%.

The two impacts are independent, so their combined impact will be somewhat less than their simple sum. The most probable impact is estimated to be on the order of: $100 (1 - (1 - 0.10) \times (1 - 0.06)) = 15.4\%$. This is, moreover, an optimistic and upper-bound estimate. We assume that at many sites the advantage will be only about one-half of this. Thus the range of impact is assumed here to be an 8% to 15% reduction in the overall cost of electricity.

The direct effect of these impacts is to save between $8 \times \$49.5\text{M} = \text{about } \400 Million and $15 \times \$49.5\text{M} = \text{about } \750 Million across the binary plants in the scenario.

The reader should note some of the reasons why this relatively large impact arises from this relatively low budget project:

- This optimization effort blends together much knowledge gained from earlier R&D efforts and experience with the U.S.

geothermal resource. This effort can therefore uncover, in some-times unpredicted ways, synergistic effects of diverse new approaches to electric plant design and resource utilization.

- This project focuses on computer modelling, which is often found to short-circuit lengthy manual trial-and-error manual approaches to design optimization.

- The geothermal electric system improvements developed by this project tend to either reduce capital outlays per plant, or to increase them only slightly. These are relatively low costs to the industry in realizing the economic benefits of the suggested improvements.

- The technical impacts of this subelement appear to be of such a type that the geothermal industry will use them, without much need for additional federal funds for equipment demonstration. The impacts are of the nature of technical "break-throughs", and therefore seem unlikely to be ignored in the design of future plants. However, this consideration should be moderated by the fact that no full-scale binary cycle geothermal electric plant has been built in the U.S., and that a cost-shared demonstration effort may be required to convince utilities that such plants are reliable and economical.

15.6 Degree of Success

Although the subelement is likely to bring about improvements in geothermal power plant design, the claims concerning the

upperbound of these impacts may be somewhat inflated. For example, in the case of the floating condenser, the estimate of benefits is based on the assumption that the temperature (ambient) range for the test case will be valid for other sites also. This is not likely to be true. Therefore, the expected degree of success of this subelement must be less than unity. We tentatively estimate the degree of success to be on the order of 0.60.

15.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (\$10 ⁶ , 1978)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	750.	1800.	1800.
PESSIMISTIC	400.	960.	960.

References

- (1) Letter from R.L. Fulton, LBL, to John Walker DGE, June, 1978.
- (2) H.S. Pines et al., "The Thermodynamic and Cost Benefits of a Floating Cooling Geothermal Binary Cycle Power Plant at Heber, California", Geothermal Resources Council TRANSACTIONS, Vol. 2, pp. 531-536, July 1978.

16.0 SUBELEMENT 2-5-B:

GEOHERMAL POWER HANDBOOK

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-5-B	CONTRACT NUMBER(S)	A361000 C022619 C071374	1112477 C024051
TITLE Geothermal Power Handbook				
CONTRACTOR(S) Brown Univ, JPL/NASA, GE, INEL, United Engineers				
RELATED PROJECTS				
2-5-2 Energy Conversion Cycle Analysis		2-5-5 Heat Rejection Systems		
2-5-3 Practical Cycles for Geothermal Plants		Analysis		
2-5-4 Geothermal Energy Conversion Source Book		2-5-6 Power Cycle Handbook		

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
☒	☒				
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	715										715
2. DGE Planned:		275	200								475
3. Additional:											
Total:	715	275	200								1190
Discounted Total of Planned and Additional:				457							

EXPECTED YEAR OF COMMERCIALIZATION	FY 1981
EXPECTED DEGREE OF SUCCESS	1.00

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	89.5
	PESSIMISTIC	36.5
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	196.
	PESSIMISTIC	80.
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	70.2
	PESSIMISTIC	28.6

SEE ATTACHED PAGES FOR RATIONALE

16.1 Projects in Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-5-2	Energy Conversion Cycle Analysis
2-5-3	Practical Cycles for Geothermal Plants
2-5-4	Geothermal Energy conversion Source Book
2-5-5	Heat Rejection Systems Analysis
2-5-6	Power Cycle Handbook

Goal

16.2 The goal of this subelement is to provide a source book of geothermal power plant and energy conversion information including details of existing facilities. This will be accomplished through breaking up the areas covered in the source book into separate projects as done above and then combining the results from all the individual projects together to form the handbook. It is hoped that this source book will aid planners use the most applicable conversion technology at each site developed.

16.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-5-2	0	30	30	30	0						30	60
2-5-3	116	70	186	0	0						0	186
2-5-4	0	0	0	35	0						35	35
2-5-5	0	22	22	0	0						0	22
2-5-6	164	313	477	210	200	0					410	887
TOTAL	280	435	715	275	200	0					475	1190
(\$78)	339	479	818	275	182	0					457	1275

16.4 Identification of Impacted Parameters

This subelement is focused on the objective of providing, in a source book form, an authoratative, complete, and current compilation of geothermal power plant and energy conversion information.

The availability of this source book will make it possible for the plant designers to design more efficient plants in a shorter time period. Therefore, the following system parameters will be impacted by this subelement.

- (i) Plant engineering cost.
- (ii) Plant efficiency, with consequent impacts on production and injection wells.

16.5 Impacts on System Parameters

The existence of the geothermal power source book will make

it possible for the plant designers to have a ready access to a comprehensive and current data base concerning power plant design. The ready availability of this information will minimize the time and effort required for designing a geothermal power plant. Assuming that the effort saved as a result amounts to 9 man months of technical staff time, the savings per plant will be equivalent to \$40,000 to \$50,000. This represents 1.6 to 2.0% of the total engineering cost.

The source book will also lead to more efficient plant design and, possibly, better plant operation. Both these factors will contribute to a reduction in the number of production as well as injection wells needed for achieving the power-on-line goals.

However, most such reductions are more appropriately credited to other DGE R&D efforts and subelements, especially those that directly carry out technical studies. Since plant designers can be expected to follow major conceptual and design improvements on the basis of DGE project reports, the Geothermal Power Handbook is expected to result in only marginal improvements in plant efficiency, perhaps on the order of 0.5 to 1.0%.

The estimated impacts of this subelement are summarized below:

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Number of Production Wells	-1.0%	-0.5%
2. Number of Injection Wells	-1.0%	-0.5%
3. Plant Engineering Cost	-2.0%	-1.5%

16.6 Degree of Success

The degree of success is assumed to be 1.0 since the projects within this subelement are oriented toward data collection, information transfer, and theoretical studies. The information is then reported in the handbook which is assumed to be disseminated to all U.S. geothermal electric plant designers.

16.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	89.5	196.	70.2
PESSIMISTIC	36.5	79.9	28.6

17.0 SUBELEMENT 2-5-C:

ANALYSIS OF HYBRID GEOTHERMAL-FOSSIL POWER PLANTS

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-5-C	354002 CONTRACT NUMBER(S) 354003 C031311
TITLE Hybrid Geothermal-Fossil Power Plants	
CONTRACTOR(S) City of Burbank	
RELATED PROJECTS 2-5-7 Energy Conversion Concepts 2-5-8 Hybrid Geothermal/Fossil Power Plants 2-5-9 Site Specific Analysis & Design	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	330										330
2. DGE Planned:		689	3000	3000							6689
3. Additional:											
Total:	330	689	3000	3000							7019
Discounted Total of Planned and Additional:				5895							

EXPECTED YEAR OF COMMERCIALIZATION	FY 1982
EXPECTED DEGREE OF SUCCESS	0.50

CALCULATED BENEFIT (DISCOUNTED TO \$. MILLIONS, 1978)	OPTIMISTIC	120.75
	PESSIMISTIC	50.0
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	10.2
	PESSIMISTIC	4.2
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	9.6
	PESSIMISTIC	4.0

SEE ATTACHED PAGES FOR RATIONALE

17.1 Projects in Subelement

<u>PROJECT CODE</u>	<u>PROJECT TITLE</u>
2-5-7	Energy Conversion Concepts
2-5-8	Hybrid Geothermal/Fossil Power
	Plants
2-5-9	Site Specific Analysis and Design

17.2 Goal

The goal of the subelement is to determine the economic and energy conservation benefits of hybrid geothermal/fossil power plants. This will be achieved by first studying all the options for geothermal development and then studying the resource at the City of Burbank. The results will be utilized for determining the best way to develop geothermal energy at the City of Burbank.

17.3 Costs

PROJECT CODE	COSTS (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-5-7	0	0	0	75	0						75	75
2-5-8	0	164	164	214	3000	3000	0				6214	6378
2-5-9	0	166	166	400	0						400	566
TOTAL	0	330	330	689	3000	3000					6689	7019
(\$78)	0	363	363	689	2727	2479					5895	6258

17.4 Identification of Impacted Parameters

In the conceptual designs so far studied for geothermal/coal hybrid electric plants, the geothermal energy provides (1) low temperature feedwater heating, (2) operation of auxiliaries, heating, air conditioning, etc., (3) boiler make-up steam, (4) cooling water, and (5) low temperature steam for coal beneficiation (sulfur removal). Coal provides heat for high temperature steam generation.

The type of resource use involved in this study is not included in the national goals for the development of geothermal energy due to the low temperature of the resource. Therefore, the impact of the successful completion of this subelement will be observed through the generation of additional power (over and above the scenario power-on-line goals), at costs below that from conventional coal-fired plants. This requires the assumption of a scenario for

the development of hybrid geothermal fossil power plants, which is done below.

17.5 Impact on System Parameters

This subelement 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 increase 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.

The first plant (City of Burbank) will be on line in 1985. The subsequent increments are assumed to occur in 1992 (with an addition of 900W), and in 2000 (an addition of 1000MW) occurring at this time. 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	$10^6 \text{ KW} \times 8760 \text{ Hrs/Yr} \times 0.8 \times 8 = 560 \times 10^8 \text{ Kwh}$
1999	2000	$2 \times 10^6 \text{ KW} \times 8760 \text{ Hrs/Yr} \times 0.8 \times 1 = 140 \times 10^8 \text{ Kwh}$
TOTAL	2000	$805 \times 10^8 \text{ Kwh}$

The saving per unit of energy, according to the City of Burbank report, is 10% of the cost of electricity from the least expensive best fossil fuel fired power plants.⁽¹⁾ The best cost is about 15 mills per kwh. The saving is, therefore:

$$\$0.015 \times 0.10 \times 805 \times 10^8 = \$120.75 \times 10^6$$

A low value of \$50 million can be assumed as pessimistic estimate. (Savings are not discounted because it is assumed that the busbar cost of electricity will escalate at approximately the discount rate.)

17.6 Degrees of Success

The degree of success is expected to be 0.50 for this subelement 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.

17.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
PESSIMISTIC	50.0	4.2	4.0
OPTIMISTIC	120.75	10.2	9.6

1. "Site-Specific Analysis of Hybrid Geothermal/Fossil Power Plants," City of Burbank, Burbank, Ca. Report No. TID-27926, June 1977.

18.0 SUBELEMENT 2-6-A:

WELL HEAD GENERATOR

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-6-A	CONTRACT NUMBER(S)	A361021 C040789 C031854
TITLE Well Head Generator			
CONTRACTOR(S) NASA, SANDIA, RCUH			
RELATED PROJECTS 2-6-1 Market Survey-Well Head Generator 2-6-2 Small Electric Generator 2-6-3 Hawaii 5-10 MWe Steam Generator			

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓	✓	✓	
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	232										232
2. DGE Planned:		1000	3000	2000							6000
3. Additional:											
Total:	232	1000	3000	2000							6232
Discounted Total of Planned and Additional:				5380							

EXPECTED YEAR OF COMMERCIALIZATION	FY 1982
EXPECTED DEGREE OF SUCCESS	0.80

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	\$21.9
	PESSIMISTIC	\$ 9.2
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	3.3
	PESSIMISTIC	1.4
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	3.1
	PESSIMISTIC	1.3

SEE ATTACHED PAGES FOR RATIONALE

18.1 Projects in Subelement

PROJECT CODE

2-6-1
2-6-2
2-6-3

PROJECT TITLE

Market Survey - Well Head Generator
Small Electric Generator
Hawaii 5-10 MWe Steam Generator

18.2 Goal

The goal is to take advantage of the potential power generation from small well head steam generators. This will be accomplished by first determining the potential market; then developing a small well head generator and finally demonstrating it at a site in Hawaii.

18.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	> 83	TOTAL 78 →	TOTAL
2-6-1	0	15	15	0							0	15
2-6-2	217	0	217	0							0	217
2-6-3	0	0	0	1000	3000	2000	0				6000	6000
TOTAL	217	15	232	1000	3000	2000	0				6000	6232
(\$78)	263	17	280	1000	2727	1653	0				5380	5660

18.4 Identification of Impacted Parameters

It is assumed that these small generating units will be used in early field development at major geothermal prospects, and in general development at smaller and relatively remotely situated prospects. The net effect is assumed to be small additions to the capacity goals of the hydrothermal development scenario.

18.5 Analysis of Benefits

This subelement was analyzed together with other DGE projects that are developing small-scale well-head generators. The analysis is documented in Appendix B of this volume.

The results of the analysis indicate that single-flash 5 MWe (net) units of the type being developed in this subelement could save between \$9.2 Million and \$21.9 Million (1978 \$) compared to the cost of the cheapest alternative electricity (nuclear or coal) in the western states.

The reader should note that this subelement is given no direct credit for reducing the cost of electricity from larger (50 MWe and up) hydrothermal electric plants.

18.6 Degree of Success

The degree of success is assumed to be affected mainly by market penetration short falls. It is estimated to be 0.8.

18.7 Results

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$10 ⁶ , 1978)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	21.9	3.3	3.1
PESSIMISTIC	9.2	9.4	1.3

19.0 SUBLEMENT 2-6-B:
GRAVITY HEAD BINARY PLANT

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER	2-6-B	CONTRACT NUMBER(S)	A361021 C024633
TITLE GRAVITY HEAD BINARY PLANT			
CONTRACTOR(S) NASA, Sperry Research Center			
RELATED PROJECTS 2-6-4 Market Survey 2-6-5 Gravity Head Binary Plant			

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)											
F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:	15										15
2. DGE Planned:		730	2900	2900	2900	1270					10,700
3. Additional:											0
Total:	15	730	2900	2900	2900	1270					10,715
Discounted Total of Planned and Additional: 10553											

EXPECTED YEAR OF COMMERCIALIZATION	FY 1983
EXPECTED DEGREE OF SUCCESS	0.60

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	\$18.2
	PESSIMISTIC	\$ 7.6
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	1.0
	PESSIMISTIC	0.5
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	1.0
	PESSIMISTIC	0.5

SEE ATTACHED PAGES FOR RATIONALE

19.1 Projects In Subelement

PROJECT CODE

PROJECT TITLE

2-6-4

Market Survey

2-6-5

Gravity Head Binary Plant

19.2 Goal

The goal of this subelement is to demonstrate the benefits of a binary system using downhole heat exchange and a gravity head fluid pump. Market survey analysis is included in this subelement to determine where this type of technology can be utilized.

19.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-6-4	0	15	15	0							0	15
2-6-5	0	0	0	730	2900	2900	2900	1270			10,700	10,700
TOTAL	0	15	15	730	2900	2900	2900	1270			10,700	10,715
(\$78)	0	17	17	730	2610	2349	2114	867			8,670	8,687

These costs are based on the DGE estimates for the Sperry Research Center Gravity Head Binary Plant project, less \$2 Million in 1978-1982 that this analysis has credited to downhole pump development, Subelement 2-2-C, Section 6.0.

19.4 Identification of Impacted Parameters

The generating units to be developed in this subelement will be driven by a downhole binary fluid heat exchanger. Thus they are best matched to using the output from a single well, and are essentially wellhead generators.

It is assumed that these small generating units will be used in early field development at major geothermal prospects, and in the general development at smaller and relatively remotely situated prospects. The net effect of this subelement is assumed to be small additions to the generation capacity goals of the hydrothermal development scenario.

19.5 Analysis of Benefits

This subelement was analyzed together with DGE projects that are developing small-scale wellhead generators. The analysis is documented in Appendix B of this volume.

The results of the analysis indicate that gravity-head 5 MWe (net) units of the type being developed in this subelement could save between \$7.6 - 18.2 Million (1978 \$) compared to the cost of the cheapest alternative electricity from nuclear or coal in the western States.

The reader should note that this subelement is given no direct credit for reducing the cost of electricity from larger (50 MWe and up) hydrothermal electric plants.

19.6 Degree of Success

In view of the uncertainty about the potential market for the output of this subelement, the degree of success of this subelement is assumed to be 0.50. This is a conservative estimate of the degree of success and it may be revised when the market survey project in this subelement yields a better determination of the potential market.

19.7 Results

TYPE OF ESTIMATE	CUMMULATIVE BENEFIT (\$10 ⁶ , 1978)	FIGURE OF MERIT	
		FY 78 TO COMPLETION	HISTORICAL (Planned + Sunk Costs)
OPTIMISTIC	18.2	1.0	1.0
PESSIMISTIC	7.6	0.5	0.5

20.0 SUBELEMENT 2-7-A:
TRANSPORT & CONVERSION OF HEAT

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-7-A	CONTRACT NUMBER(S) 05 ENG 28
TITLE TRANSPORT & CONVERSION OF HEAT	
CONTRACTOR(S) ORNL	
RELATED PROJECTS 2-7-1 Transport and Conversion of Heat at Moderate Temperature	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
			✓		
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		907										907
2. DGE Planned:			490	500	0							990
3. Additional:												0
Total:		907	490	500	0							1897

Discounted Total of Planned and Additional: 945

EXPECTED YEAR OF COMMERCIALIZATION	FY 1981
EXPECTED DEGREE OF SUCCESS	0.60

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	23.1
	PESSIMISTIC	14.2
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	14.7
	PESSIMISTIC	9.0
HISTORICAL FIGURE OF MERIT (W/ SUNK COSTS)	OPTIMISTIC	7.5
	PESSIMISTIC	4.6

SEE ATTACHED PAGES FOR RATIONALE

20.1 Projects In Subelement

PROJECT CODE

2-7-1

PROJECT TITLE

Transport and Conversion of Heat
at Moderate Temperature

20.2 Goal

The goal of the subelement is to develop an advanced heat exchanger for use in geothermal binary cycles. Current emphasis is on working fluid condensers (fluted tubes and/or drain off skirts).

20.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83	TOTAL 78 →	TOTAL
2-7-1	527	245	772	490	500	0					990	1762
TOTAL	527	245	772	490	500	0					990	1762
(\$78)	638	270	908	490	455	0					945	1853

20.4 Identification Of Impacted Parameters

The major objective of this subelement is to develop a more efficient and less expensive shell and tube type binary fluid condenser. The fluted tube design is expected to reduce the requirement of heat exchange area. The fluted tube design can be

expected to increase the O&M costs for the heat exchanger (condenser).

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

(i) The capital cost of the condenser and heat rejection equipment.

(ii) Utility general O&M cost factor (binary systems).

20.5 Impacts On System Parameters

It was estimated by the Project Manager for this subelement that the film coefficient of the organic fluid increases 3 - 7 times when the fluted tube design is utilized instead of the finned tube design in heat exchangers.⁽¹⁾ On the basis of this claim, the following analysis of benefit of this subelement leads an estimation of the impacts of this activity.

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) with respect to U, keeping Q & T_m constant give:

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

¹Direct Communication, Mr. John Mitchel, Oak Ridge National Laboratory.

FIGURE 20-1
A SECTION OF FLUTED TUBE

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.

Condensers usually employ extended surface tubing and the ratio A_o/A_i is generally about 2.5. Other terms have the following values:

$$h_i \text{ (Water, } 5 \text{ ft/s, } 85^\circ\text{F)} = 11300 \text{ Btu/} \\ \text{(hr. ft}^2\text{ }^\circ\text{F)} \text{ (Reference 1)}$$

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

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

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

Substituting these values into equation 3 gives:

$$\frac{1}{U} = \frac{2.5}{1130} + \frac{1}{250} + 0.0010 \times 2.5 = 0.00921 \\ U = 108.60 \text{ Btu/(hr. ft}^2\text{ }^\circ\text{F)}$$

If fluted tubes are used, extended surface has different configuration (See Figure 20-1) and the ratio A_o/A_i is much less than 2.5, but is slightly greater than 1.183 (the outside/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 20-1.

20.5.1 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).

TABLE 20-1

EFFECTS OF FLUTED TUBES

	REFERENCE 1 FINNED TUBE	FLUTED TUBE	
		$h_i=3 \times 250^*$	$h_o=7 \times 250^*$
U*	108.60	214.56	256.49
U* (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.

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

FIGURE 20-2

THE ASSUMED LOG MEAN TEMPERATURE DIFFERENCE OF THE CONDENSER

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

For a 50 MW_e output, let us assume that 70 MW_e gross is to be generated with efficiency of 25%, i.e., 75% of the heat is rejected or $(75/25) \times 70 \text{ MW}_e = 210.00 \text{ MW}_e = 716.73 \times 10^6 \text{ Btu/hr}$ transferred through the condenser. If a Δt_m is assumed as shown in Figure 20-2 the total areas required and costs for finned tube and fluted tube would be as shown in Table 20-2. It is noted that although the cost figures in Table 20-2 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%.

22.5.2 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 20-2). A possible additional cost might occur in relation to the vertical position of the condenser, which may or may not be significant. All things considered, it is difficult to make an accurate estimate of the cost changes due to the use of fluted tubes and vertical condenser. Therefore, it is assumed that the fluted tube-vertical condenser increase the condenser O&M costs by 10%.

TABLE 20 - 2

COST ESTIMATES FOR TUBE CONDENSERS
(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.

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:

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Capital Cost of Condenser and Heat Rejection Equipment	-5.6%	-4.4%
2. Utility General O&M Cost Factor (Binary)	+2.0%	+2.0%

20.6 Degree of Success

To date, there has been only one laboratory test of this technology. There are problems in performance and in scaling up to a size usable in a geothermal plant. It is estimated, therefore, that the expected degree of success is about 0.6.

20.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 to COMPLETION	(PLANNED & SUNK COSTS)
OPTIMISTIC	23.1	14.7	7.5
PESSIMISTIC	14.2	9.0	4.6

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.

21.0 SUBLEMENT 2-7-B:
DIRECT CONTACT CONDENSER RESEARCH

BENEFIT/COST RATIONALE AND RESULTS

SUBELEMENT NUMBER 2-7-B	CONTRACT NUMBER(S) CO 71375
TITLE Direct Contact Condenser Research	
CONTRACTOR(S) INEL	
RELATED PROJECTS 2-7-2 Direct Contact Research	

CURRENT STATE OF R&D: (CHECK APPROPRIATE STAGES)					
		✓			
Preliminary Study	Basic Research	Exploratory Development	Advanced Development	Engineering Development	Demonstration & Commercialization

(\$1000s, CURRENT YEAR)												
	F.Y.	To 78	78	79	80	81	82	83	84	85	>85	TOTAL
1. Sunk:		0										0
2. DGE Planned:			100	0								100
3. Additional:												0
Total:		0	100	0								100
Discounted Total of Planned and Additional: 100												

EXPECTED YEAR OF COMMERCIALIZATION FY 1983
EXPECTED DEGREE OF SUCCESS 0.50

CALCULATED BENEFIT (DISCOUNTED TO \$ MILLIONS, 1978)	OPTIMISTIC	44.5
	PESSIMISTIC	29.6
FIGURE OF MERIT (W/O SUNK COSTS)	OPTIMISTIC	222.5
	PESSIMISTIC	148.0
HISTORICAL FIGURE OF MERIT (W/SUNK COSTS)	OPTIMISTIC	222.5
	PESSIMISTIC	148.0

SEE ATTACHED PAGES FOR RATIONALE

21.1 Projects In Subelement

PROJECT CODE

2-7-2

PROJECT TITLE

Direct Contact Research

21.2 Goal

The goal of this subelement is to develop heat transfer correlations and design criteria for direct contact boilers, preheaters and condensers. Current emphasis is on the direct contact condenser.

21.3 Costs

PROJECT CODE	COST (\$1000) BY FISCAL YEAR											TOTAL 78 →	TOTAL
	PRIOR 77	77	TOTAL	78	79	80	81	82	83	>83			
2-7-2	0	0	0	100	0							100	100
TOTAL	0	0	0	100	0							100	100
(\$78)	0	0	0	100	0							100	100

21.4 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 subelement. Therefore, the following system parameters are likely to be affected by this subelement:

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

21.5 Impacts On System Parameters

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 exchange 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% is reasonable as a pessimistic estimate.

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 is reasonable 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 estimated impact of this subelement:

IMPACTED PARAMETER	ESTIMATED IMPACT	
	OPTIMISTIC	PESSIMISTIC
1. Capital Cost of Condenser and Heat Rejection Equipment	-6.0%	-4.0%
2. Utility General (&M Cost Factor (Binary))	0.0%*	0.0%*

* These estimates may be changed later, depending on data on the rate of loss of working fluid.

21.6 Degree Of Success

The estimated degree of success for this subelement is 0.50. This is due to the fact that the technology being looked at is not well understood. There are also performance problems and problems in scaling up to a size useful in geothermal power plants.

21.7 Results

TYPE OF ESTIMATE	CUMULATIVE BENEFITS (10 ⁶ \$78)	FIGURE OF MERIT	
		FY78 TO COMPLETION	HISTORICAL (PLANNED & SUNK COSTS)
OPTIMISTIC	44.5	222.5	222.5
PESSIMISTIC	29.6	148.0	148.0

APPENDIX B

ANALYSIS OF BENEFITS FROM
5 MWe (Net) WELLHEAD GEOTHERMAL
GENERATING SYSTEMS

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- 1.0 INTRODUCTION
- 2.0 APPROACH OF ANALYSIS
 - 2.1 General Assumptions
 - 2.2 Steps in the Analysis
- 3.0 WELL HEAD PLANT COSTS
 - 3.1 Single Flash Steam Plant
 - 3.2 Gravity Head Binary Plant
 - 3.3 Helical Screw System
- 4.0 BUSBAR AND TRANSMISSION COSTS
 - 4.1 Busbar Costing Method
 - 4.2 Busbar Costs for Wellhead Plants
 - 4.3 Busbar Costs for Coal and Nuclear Plants
 - 4.4 Transmission Costs
 - 4.5 Total Costs for Electricity from Coal and Nuclear
- 5.0 ESTIMATE OF TOTAL SAVINGS
 - 5.1 Savings per Plant
 - 5.2 Installation Scenario
 - 5.2.1 Mix of Plant Types
 - 5.2.2 Installation Schedule and Discounting
 - 5.2.3 Total Savings
 - 5.2.4 Contribution to Benefit by Plant Type
 - 5.2.5 A Final Note

REFERENCES

1.0 INTRODUCTION

This appendix documents an analysis of economic benefits associated with the potential use of three types of geothermal wellhead generators. These are (1) Single flash steam system, (2) Gravity-head binary system, and (3) Helical screw (total flow) system. Each is assumed to be a 5 MWe (net) plant that can be driven by one geothermal production well, with fluid returning to one reinjection well.

Most of the attention to electric plant design for hydrothermal electric development has been focused on plants of about 50 to 100 MWe (net) capacity. Plants of this size range need to be fed by a number of producing wells. This requirement for multiple wells can lead to a number of problems, the main one of which appears to be the time lag between the completion of the first successful well in a field and the completion of enough additional wells in the immediate vicinity to allow the construction of a power plant.

At least in theory, there are many sites and situations where use of a generator that would run off the output from a single well could be advantageous. These include:

- (1) Generation of electricity for further development of the geothermal prospect.
- (2) Development of prospects where the geology of the field makes the gathering system for large plants prohibitively expensive.
- (3) General development of a field where various delays in drilling or construction make it necessary to leave productive wells capped and unused for a period of years

with no return on investment.

- (4) Development of resources that are or might seem to be too small to support a 50 MWe or larger plant.

Rather than analyzing all of these possibilities, we have elected to estimate the general economics of using the well-head generators at remote sites, on the grounds that there could be many cases where a 5 MWe (net) geothermal power plant could be used to advantage.

The results of the analysis suggest that if these small units contribute as much as 5% capacity as is postulated in the hydrothermal development scenario, that they could deliver savings totalling on the order of \$20 to \$45 Million, compared to generating the same power from coal or nuclear electric plants in the western states.

2.0 APPROACH OF ANALYSIS

2.1 General Assumptions

Rather than assume that these units will compete with the 50 MWe plants in the main scenario, which postulates a total of 18,600 MWe (net) capacity on line by 2000, it is postulated that the wellhead generators will provide additional capacity amounting to 5% of that in the scenario. This amounts to 930 MWe, or 186 wellhead systems of 5 MWe size.

It is further assumed that the electricity generated by these plants will displace electricity from coal or nuclear plants. The economic "saving" is accordingly assumed to be the total reduction in the cost of delivered electricity at sites very near the wellhead generators, compared to typical bus bar plus transmission costs for coal or nuclear-fueled electric plants.

2.2 Steps in the Analysis

The analysis is presented in the following sequence in the sections below:

- (1) Wellhead plant capital and O&M costs were estimated for each of the three plant types: Single Flash, Gravity-Head Binary, and Helical Screw.
- (2) Bus bar costs and transmission costs were estimated for the wellhead plants and for western coal and nuclear-powered plants. Alternative costs of electricity were estimated.
- (3) The relative competitiveness of each wellhead plant was estimated, based on cost of electricity delivered to the distribution system, was estimated, and the likely dollar savings per wellhead plant was calculated.

- (4) The scenario for wellhead plant use was developed, and the total savings from 186 plants was summed and discounted to 1978 dollars.

3.0 WELLHEAD PLANT COSTS

3.1 Single Flash Steam Plant

The capital cost for a 5 MWe (net) single-flash steam electric plant was derived from cost estimates for a similar plant developed for Lawrence Livermore Laboratory (LLL) by Rogers Engineering in 1975 (see note 1 in Table 1). The LLL estimate was \$1,826 K for a 5 MWe (gross) plant cooled by 20⁰C river water, and disposing condensed steam into the river; unflashed brine was assumed to require no pumping for reinjection. The plant cost estimate was upgraded to a more comprehensive design that provides for (1) pumped reinjection of all brine and condensate, (2) A closed-loop heat-rejection system with cooling towers, (3) More sophisticated electrical equipment to allow connection to a 13.8 kv busbar, and (4) Improved structures for housing the turbogenerator and associated equipment.

These changes raise the estimated cost, in first-quarter 1975 \$, to \$3090k, from the original estimate of \$1,826k for the

TABLE 1

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY
MWe (GROSS) SINGLE-FLASH WELLHEAD
GEOTHERMAL ELECTRIC PLANT

COST CATEGORY	Installed Cost (\$1000s, 1st Q, 1975)	
	LLL Design	Upgraded Design
MECHANICAL EQUIPMENT		
(1) Turbine-Generator	\$825.5	\$825.5
(2) Flash Tank	59.7	59.7
(3) Condenser	87.9 ^a	87.9 ^e
(4) Feed Pumps	35.3 ^a	70.6 ^d
(5) Cooling Tower	----	114.1 ^c
(6) Injection Pumps	----	133.8 ^f
(7) Auxiliary Systems	11.0	34.3 ^f
PIPING AND INSTRUMENTATION		
(8) Piping, Valves, & Insulation	241.8 ^b	314.3 ^g
(9) Instrumentation & Controls	128.2 ^b	270.7 ^h
(10) Electrical Equipment	-----	252.2 ^c
CIVIL		
(11) Site and Foundations	13.3	66.5 ^j
(12) Buildings	14.4	72.0 ^j
(13) Packing, Freight, Insurance	56.4	112.8 ^k
(14) Profit on Contractor	48.9	97.8 ^k
Supplied Labor & Materials	-----	-----
ESTIMATED COST	1,522.4	2,512.2
ENGINEERING	75.4	200.0
CONTINGENCY (15% of EC)	228.4	377.0
BUDGET ESTIMATE	\$1,826.2	\$3,089.2

Notes to Table 1:

- a. LLL estimates cost of condenser and circulating pump combined. Approximately 110 kW of pumping is used here. From the Heber design, each kW of pump costs about $2460/(7290 \times 1.05) = \321 . The estimated pump cost of $\$110 \times 321 = \$35.3K$ is subtracted from the pump plus condenser cost of $\$123.2K$ to leave $\$87.9K$ for the condenser.
- b. Instrumentation, controls, and electrical equipment are lumped together in a single module in the LLL design.
- c. Injection pumps: Not included in LLL design. Cost is estimated to be proportional to relative mass flow reinjected, based on cost of 50 MWe (net) plant pumps, adjusted to 5 MWe (gross) and for inflation. Two operating pumps and one standby pump are assumed.

$$\begin{aligned} \text{Cost} &= \left(\frac{0.505}{4.60} \right) \left(\frac{3760 \times 1.5}{7290 + 3760/2} \right) \left(\frac{2460}{59.1} \right) \left(\frac{1}{1.05} \right) \\ &= \$133.8K \end{aligned}$$

- d. Cooling Tower: Not included in LLL design. Flow through tower is assumed to be twice that through the LLL river-cooled plant. Cost is assumed to be proportional to relative mass flow and the cost of the 50 MWe (net) cooling tower, adjusted to 5 MWe (gross) and for inflation.

$$\begin{aligned} \text{Cost} &= (2)(1.202/28.7)(1,690)(50/59.1)(1/1.05) \\ &= \$114.1K \end{aligned}$$

- e. Feed Pumps: Cooling flow is assumed to be twice that of LLL design.
- f. Auxiliary Systems: Assumed to amount to 8% of the cost of such items in the 50 MWe (net) plant.

$$\text{Cost} = (450)(0.08)/(1.05) = \$34.3K$$

- g. Piping: Assumed to be 30% higher than for LLL design, to accomodate cooling tower and higher cooling flow rates.
- h. Instrumentation and Controls: Assumed to be 20% of that for the 50 MWe (net) plant, adjusted to 5 MWe (gross) and for inflation.

$$\begin{aligned} \text{Cost} &= (1,600)(0.20)(50/59.1)(1/1.05) = \\ & \quad 59.1 \end{aligned}$$

- i. Electrical Equipment: Assumed to be 10% of that for the 50 MWe (net) plant, adjusted to 5 MWe (gross) and for inflation.

$$\text{Cost} = (3,130)(0.10)(50/59.1)(1/1.05)=252.2$$

- j. Site & Foundations; Building: Assumed to about 5 times the LLL estimate, to allow for additional equipment and longer plant life.
 - k. Assumed to be about twice the LLL estimate, to allow for additional materials and labor for heat rejection system.
 - l. "Conceptual Design of 5 MW Wellhead Located Geothermal Steam Turbine Driven Electric Generating Plant, Prepared for Lawrence Livermore Laboratory, University of California", Report S-75003, Rogers Engineering Co., Inc., San Francisco, Ca., April, 1975.
-

5 MWe (gross) plant. Given the additional pumping power requirements in the upgraded design, the gross capacity of the plant is estimated to be about 12% above the net capacity. Thus it is assumed that almost all components in the plant will be increased in size to this degree, with an equal percentage increased in overall cost. Inflation between 1st quarter 1975 and 3rd quarter 1978 adds another 25.6% increase to costs. The final estimate for the 5 MWe (net) plant, in mid-1978 \$, is

$$\text{Cost} = \$3,090\text{k} \times 1.12 \times 1.256 = \$4,350\text{k}$$

O&M costs per year are assumed to be 3% of the installed capital cost, or \$130k per year.

3.2 Gravity Head Binary Plant

The gravity head binary geothermal electric plant concept differs from the conventional binary cycle plant design in that the primary heat exchanger is placed down hole. As developed by Sperry Research Center, the concept has a dual-tube heat exchanger approximately 2100 feet long mounted inside of the well surface casing.⁽¹⁾ The resulting arrangement has an outer annulus (in which geothermal brine flows upward), an inner annulus (in which the organic working fluid is heated as it flows downward), and an inner tube (in which the heated working fluid flows upward). A turbine, mounted at the downhole junction of the inner tube and inner annulus, takes some of the power in working fluid to drive a pump in the outer annulus. This pump provides sufficient pressure to the brine to keep it from flashing

and to reinject the fluid into a disposal well without need for additional pumping power.

The comparative advantages of this approach relative to the surface-based heat exchanger binary-cycle plant include the following items:

- (1) An organic fluid boosting pump is not required. A small start-up pump is necessary, but this can be used for many plants.
- (2) The heat exchanger and downhole pump are combined into the same unit, which reduces the combined cost of these items.
- (3) A reinjection pump is not required.
- (4) Most of the surface plant components are smaller because the plant has a higher efficiency and lower parasite power requirements. A great deal of the parasite power generation is displaced from the turbine-generator unit to the heat-exchanger-pump unit.

Sperry estimates that the capital cost of a gravity-head plant is 30% less than the cost of a conventional binary plant.⁽²⁾

This figure appears to be reasonable because of the above-described reduction in number and sizes of components.

The cost of a conventional binary plant has been estimated to be \$6,600k for a 5 MWe (net) size, in 1975 dollars.⁽³⁾ Thus correcting for inflation to mid-1978 dollars the estimated cost becomes:

$$\text{Cost} = \$6,600\text{k} \times 0.70 \times 1.256 = \$5,800\text{k}.$$

The annual O&M cost of this plant is assumed to be 5% of the capital cost, or \$290k per year. Most of this cost will

be related to pulling, cleaning, and maintaining the heat-exchanger-pump unit.

3.3 Helical Screw System

The helical screw system uses a total flow expander as the prime mover. In principle it can extract more energy from the geothermal brine than can a system where only flashed steam drives a turbine.

The helical screw system would most likely be used at the relatively high temperature reservoirs, and thus compete for market share with the single-flash steam system.

Mr. Roger Spankle, of Hydrothermal Power Company, estimates that the prime-mover and generator portion of this system would cost about \$350/kw for the first unit, and decrease to perhaps \$180/kw for the tenth and following units. This is equivalent to the turbine-generator plus controls for the single stage flash plant. Therefore the cost per plant works out to be roughly the same as the single-flash plant. The two systems were therefore lumped together for economic analysis.

It was further assumed that the helical screw system would capture only about 20% of the high-temperature market, since it represents a much less proven concept than the flashed steam system.

4.0 BUSBAR AND TRANSMISSION COSTS

4.1 Busbar Costing Method

Busbar costs of geothermal, coal-fueled, and uranium-fueled electric plants were calculated from capital and O&M costs using a simplified procedure developed by MITRE. (4) The method considers escalation rates, cost of capital, tax structure, and other considerations to derive a busbar cost for a specific plant type in a given vintage year (here, 1978).

4.2 Busbar Costs for Wellhead Plants

Busbar costs for geothermal electricity must consider both plant costs (as developed in Section 3.0) and geothermal well costs. Because well costs vary so much from site to site, both low and high cost of wells estimates were used in the calculations.

In the low-cost case, typical of moderate depth wells in sedimentary rock, production wells are estimated to cost \$600K, and injection wells \$400K, for a total capital cost of \$1,000K. O&M costs are estimated to be 3.0% of the capital cost, or \$30K per year. In the high-cost case, typical of deeper wells in harder rock, production wells are estimated to cost \$1,000K, and injection wells \$700K, for a total of \$1,700K. O&M costs, again at 3%, are estimated to be \$51K per year.

The general assumptions for busbar cost calculations are shown in Table 2. The estimated busbar costs are shown in Table 3.

TABLE 2

ASSUMPTIONS FOR WELLHEAD GENERATOR
BUSBAR COST CALCULATIONS

Well Life	15 years
Plant Life	15 years
Tax Life	10 years
Equity Fraction	60%
Effective Investment Tax Credit Rate	12%
Effective Income Tax Rate	50%
Property Tax Rate	1%
Capital Cost Rate	10%
Price Deescalator	5%
O&M Deescalator	5%
Electricity Deescalator	7%
Vintage Year	1978
Capacity Factor	0.80

TABLE 3

GENERATING EQUIPMENT COST AND BUSBAR
COST FOR WELLHEAD GENERATORS

	PLANT DESIGN		
	<u>SINGLE FLASH STEAM</u>	<u>GRAVITY HEAD BINARY</u>	<u>HELICAL SCREW SYSTEM</u>
<u>Low-Cost Wells</u>			
Capital (\$1000s)	5,350	6,800	5,350
O&M (\$1000s/yr)	160	310	160
Busbar (mills/kwh)	18.9	26.8	18.9
<u>High-Cost Wells</u>			
Capital (\$1000s)	6,050	7,500	6,050
O&M (\$1000s)	181	341	181
Busbar (mills/kwh)	21.4	29.4	21.4

4.3 Busbar Costs for Coal and Nuclear Plants

Busbar costs for coal and nuclear-fueled plants were derived from assumptions and calculations previously worked out for the western states, and then escalated to mid-1978 costs.

Since construction and coal costs, in particular, exhibit regional variations, separate data are given for the Pacific and Mountain Census Regions. The Pacific Region comprises California, Washington and Oregon, and the Mountain Region comprises New Mexico, Utah, Nevada, Montana, Idaho, Wyoming and Colorado.

For the Pacific Region, the busbar costs are 26.2 mills/kWh for nuclear, and 28.9 mills/kWh for coal. For the Mountain Region, the busbar costs are 21.9 mills/kWh for coal, and 24.7 mills/kWh for nuclear.

4.4 Transmission Costs

Transmission costs are highly site and demand specific. Instead of formulating and costing various transmission scenarios, the average transmission cost for all U.S. electricity was estimated from 1972 data for the entire U.S. (6). Values from that report were adjusted to 1978 dollars, resulting in the following estimate of the contribution of generation, transmission and distribution costs for electricity delivered to all users (industrial, commercial, and residential).

<u>Source</u>	<u>mills/kWh</u>
Generation, Total	25.0
Transmission Equipment	6.6
Transmission O&M	0.5
Distribution Equipment	5.3
Distribution O&M	4.2
TOTAL	<u>41.6</u>

The resulting estimate of total cost of electricity (41.6 mills/kWh) is within 1% of that reported for the average cost of electricity to commercial users in 15 major western cities in June 1978, as cited by the U.S. Bureau of Labor Statistics. Thus we assume that we are within reasonable bounds when estimating the general average cost of transmission to be on the order of $6.6 + 0.5 = 7.1$ mills/kWh.

4.5 Total Costs for Electricity from Coal and Nuclear

When wellhead geothermal plants can be sited near demand centers, as described in Sections 1.0 and 2.0, we assume that they will compete with transmitted electricity from nuclear plants (Pacific Region) or coal plants (Mountain Region). We ignore distribution costs, which are assumed to be the same in any case.

Transmitted nuclear power in the Pacific Region is estimated to cost $26.2 + 7.1 = 33.3$ mills/kWh. Transmitted coal power in the Mountain Region is estimated to cost $21.9 + 7.1 = 29.0$ mills/kWh.

5.0 ESTIMATE OF TOTAL SAVINGS

This section estimates the total economic savings expected from the use of well-head generators. Included are estimates of the savings per plant of each type in either the Pacific Region or Mountain Region, total savings across all plants, and total savings expected to be done from each of the three types of plant.

5.1 Savings Per Plant

The savings per plant per year were estimated as follows. The results are displayed in Table 4.

- (1) For each plant type and region, the capacity factor at which the wellhead generator is marginally competitive with the lowest price competitor (busbar plus transmission) was calculated. For the low cost flash system in the Pacific Region, this is:

$$18.9 / (0.8 \times 33.3) = 0.45.$$

This is assumed to be the lowest capacity factor at which each plant type would be installed in each region.

- (2) Assuming that wellhead plants will be installed where capacity factors would lie between this lower bound and 0.80 as the upper bound, the mean of the lower and upper bound capacity factors was taken to be the average capacity factor for each class of application. In our example, this is:

$$(0.45 + 0.80) / 2 = 0.62.$$

This value is called the "average capacity factor" in Table 4.

TABLE 4

ESTIMATED CAPACITY FACTORS, BUSBAR COSTS, AND
SAVINGS PER PLANT FOR 5 MWe(net) WELLHEAD
GENERATORS IN PACIFIC AND MOUNTAIN STATES

	<u>FLASH AND HELICAL SYSTEMS</u>		<u>GRAVITY HEAD SYSTEMS</u>	
	<u>LOW COST</u>	<u>HIGH COST</u>	<u>LOW COST</u>	<u>HIGH COST</u>
A. Busbar Cost at 0.8 Capacity Factor	18.9	21.4	26.8	29.4
B. PACIFIC REGION (Competes with nuclear, at 33.3 mills/kWh)				
1. Marginal Competitive Capacity Factor	0.45	0.51	0.64	0.71
2. Average Expected Capacity Factor	0.62	0.66	0.72	0.76
3. Average Busbar Cost (mills/kWh)	24.4	25.9	29.7	30.9
4. Savings per Plant/Year (\$1000s)	\$242.	\$214.	\$114.	\$80.
C. MOUNTAIN REGION (Competes with coal, at 29.0 mills/kWh)				
1. Marginal Competitive Capacity Factor	0.52	0.60	0.74	0.81
2. Average Expected Capacity Factor	0.66	0.70	0.77	0.80
3. Average Busbar Cost (mills/kWh)	22.9	24.4	27.8	29.4
4. Savings per Plant/Year (\$1000s)	\$176.	\$141.	\$40.	\$0.

- (3) Using this estimated average capacity factor, the savings per plant per year, relative to use of power from the competing source was calculated. For Pacific Region low-cost flash system, this is:

$$(33.3 - 24.4)(0.62)(8760)(5000)/(1000) = \$242,000,$$

where the units are:

$$(\text{mills/kWh})(\text{capacity factor})(\text{hours/year})(\text{kilowatts})/(\text{mills}/\$).$$

Savings per plant per year range from zero to \$242,000.

5.2 Installation Scenario

5.2.1 Mix of Plant Types

The mix of plant types and regions is assumed to be similar to that described for U.S. Geothermal prospects in Circular 790 (U.S. Geological Survey, 1979). There 47 prospects of high or moderate temperature (200°C or higher, or $150^{\circ}\text{C} - 199^{\circ}\text{C}$) are listed for the Pacific and Mountain Region states. These breakdown as follows: High-Temperature Pacific 20%; Moderate-Temperature Pacific, 35%; High-Temperature Mountain, 10%; and Moderate-Temperature Mountain, 35%.

Thus, for high cost plants, the typical savings per plant is:

$$(\$1000) \times (9.2 \times 214 + 0.1 \times 141 + 0.35 \times 80 + 0.35 \times 0.)/0.65 \\ = \$131,000/\text{year}.$$

Note that the high cost gravity head plants are not installed, because they are not competitive.

Similarly, for the low cost plants, the typical savings per plant is:

$$(\$1000) \times (0.2 \times 242 + 0.1 \times 176 + 0.35 \times 114 + 0.35 \times 40)/1.0 \\ = \$120,000/\text{year}.$$

5.2.2. Installation Schedule & Discounting

Whatever the number of plants (discussed below) it is assumed that they will go on line in the period 1985-2000. If there are M plants, then each year is assumed to have M/15 plants per year being installed.

Given a 15 year plant life, and a fixed value V of the per year savings per plant, the discounted value of the savings, at a 10% discount rate is given by

$$S = ((1 - (\frac{1}{1.10})^{15}) / 0.10) V = 7.606V.$$

This is the savings discounted to the year of inflation.

Given the assumptions in the first paragraph, the value of M plants, with an average savings per plant (in its vintage year) of S dollars, is given by (in 1985):

$$S_m = (7.606S) \cdot M/15 = 3.856 \cdot M \cdot V$$

This must be further discounted to 1978, with a final value of

$$\begin{aligned} PV (\text{Wellhead}) &= (3.856)(1/140)^7 MxV \\ &= 1.979xMxV. \end{aligned}$$

Thus, for example, if a total of 100 wellhead generators were installed, with an average savings of \$100,000 per year per plant, the total savings (present value, 1978) would be:

$$1.979 \times 100 \times \$100,000 = \$19.8 \text{ Million}$$

5.2.3 Total Savings

Estimating the number of plants to be installed is the most

sensitive part of this analysis, but reasonable lower and upper bounds can be set.

As a lower bound, we arbitrarily estimate that perhaps 2 wellhead plants, on the average, might be technically feasible at each of the 47 Pacific and Mountain Region Prospects with temperature estimates of 150°C or higher listed in U.S.G.S Circular 790, for a low estimate of 94 technically feasible plant. Some 16 of these plants (High Cost, Gravity Head, Mountain Region) will not be economically feasible, leaving 78 plants.

As an upper bound, we estimate that as much as 5% of the power goal for 2000 in the hydrothermal development scenario could be added to that goal by wellhead generators. This is equivalent to 186 5 MWe (net) plants.

In either case, the savings per year per plant would average \$124,000, the weighted average across the economically feasible plants.

For 78 plants (pessimistic estimate) the total benefit is then:

$$1.979 \times 78 \times \$124,000 = \$19.1 \text{ Million.}$$

For 186 plants (optimistic estimate) the total benefit is \$45.6 Million.

5.3.4 Contribution to Benefit by Plant Type

The flash-steam and helical screw plants, installed at high temperature resources, deliver greater savings per plant, but there is more moderate temperature resources to which the gravity-head binary plant can be applied.

The gravity head installations represent 64% of the plants, but only 40% of the total savings, or \$7.6 - 18.2 Million.

The single-flash steam and helical screw plants share the remaining 60% of the total savings. Of this, 80% is expected to be contributed by the flash plants (See Section 3.3). The flash plants thus contribute \$9.2 - 21.9 Million, while the helical screw plants contribute \$2.3 - 5.5 Million.

5.3.5 A Final Note

There is a situation where the market for these small generators could be eventually much greater than that postulated in this analysis. There is recent general discussion in the geothermal industry that well-head plants of about 5 MWe capacity could replace 50-200 MWe plants as the design of choice. The reason is simply that power could be extracted from each within 1 year after its construction start, rather than after say 4 to 8 years. The immediate revenue from each successful geothermal well is economically very valuable, given the current conditions of inflation and reservoir uncertainty.

If well-head generators begin to replace larger plants for general development of geothermal fields the benefits from these R&D efforts could be much larger than those estimated here.

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