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**SITE-SPECIFIC ANALYSIS OF HYBRID
GEOTHERMAL/FOSSIL POWER PLANTS**

June 1977

Work Performed Under Contract Nos. EG-77-C-03-1311;
EY-76-C-03-0115-108

City of Burbank
Burbank, California

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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GEOTHERMAL/FOSSIL POWER PLANTS**

Prepared for the

**UNITED STATES ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
Division of Geothermal Energy**

Under Contract No. E(0-4-1311)

PRIME CONTRACTOR: CITY OF BURBANK

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EP

Sites of Known Geothermal Resource Areas (KGRAs)

ABSTRACT

A preliminary economic analysis of a hybrid geothermal/coal power plant has been completed for four geothermal resource areas: Roosevelt Hot Springs, Coso Hot Springs, East Mesa and Long Valley. A hybrid plant would be economically viable at Roosevelt Hot Springs and somewhat less so at Coso Hot Springs. East Mesa and Long Valley show no economic promise. A well-designed hybrid plant could use geothermal energy for boiler feedwater heating, auxiliary power, auxiliary heating, and cooling water. Construction and operation of a hybrid plant at either Roosevelt Hot Springs or Coso Hot Springs is recommended.

Brown University provided the theoretical basis for the hybrid study. A modified version of the Lawrence Berkeley Livermore GEOTHM Program is the major analytical tool used in the analysis. The Intermountain Power Project is the reference all coal-fired plant. Costing methods followed recommendations issued by the Energy Research and Development Administration.

ACKNOWLEDGMENTS

This study was supported by the Energy Research and Development Administration, Division of Geothermal Energy. Clifton B. McFarland was the Program Manager for ERDA. The work was performed by the City of Burbank's Public Service Department, with the analytical modeling being done by the Pacific-Sierra Research Corporation. Richard E. Roxburgh was the Program Manager for the City of Burbank and was assisted by Acey L. Floyd, Science Advisor to the City.

The study is based on theory developed at Brown University by Professors Ronald DiPippo, Joseph Kestin, and H. Ezzat Khalifa. This theory provided a clear and organized method of analysis of the hybrid geothermal/fossil fuel power plant.

The cost calculations are based upon a modification of the computer simulation "A Thermodynamic Process Program for Geothermal Power Plant Cycles" developed by M. A. Green and H. S. Pines of the Lawrence Berkeley Laboratory. This simulation provided the basis for the cost optimization process used for the geothermal portion of the study.

The analysis required an optimally sited coal-fired power plant of the latest state-of-the-art design as a reference in order to provide realistic design and cost considerations for the hybrid plant analysis. The Intermountain Power Project (Joseph C. Fackrell, President) power plant was selected as the reference because of its siting, size, design, and schedule for first operation in mid-1980s. The use of this ideally sited, cost efficient, reference plant greatly enhanced the realism of the analysis.

EXECUTIVE SUMMARY

Introduction

Liquid dominated geothermal resources must be extensively used if geothermal energy is to provide 10 000 to 15 000 MW of electrical power by 1985. The conversion of this resource relies upon the development of new and, for the most part, commercially unproven technology.

Present electric power generation and distribution technology is directed at large plants -- 3000 to 5000 MW -- to ensure the most economic delivery of electrical energy to the consumer. The advantages of using this technology for conversion and distribution of geothermal energy are readily apparent. However, the properties of geothermal energy in terms of temperature, pressure, and quantity are far different from the properties of the heat energy produced from fossil fuels.

In 1975, the City of Burbank suggested that fossil fuel and geothermal energy could be combined to mutual advantage in a single power plant. By 1976, the City, Pacific-Sierra Research Corporation (PSR), and other investigators suggested that geothermal energy and fossil fuels could be used to best advantage in a hybrid cycle. Geothermal energy could provide low temperature heat to the boiler feedwater of a Rankine steam cycle, reducing the need for regeneration. The fossil fuel could provide the high temperature heat at a more efficient level of use. A recent study by Brown University, "Hybrid Fossil-Geothermal Power Plants" revealed several important advantages of the hybrid cycle. (See Appendix F.)

- Thermodynamically, the hybrid system is superior to a combination of the two state-of-the-art systems, one using only fossil fuel and the other using only geothermal energy. Therefore, to achieve a given

generating capacity, the hybrid plant would require less fossil fuel than a conventional steam plant.

- Equivalent geothermal energy conversion efficiencies are substantially higher in feedwater heating than in a state-of-the-art binary fluid or flash plant.
- Geothermal fluids with marginal temperatures ($150^{\circ}\text{C}/300^{\circ}\text{F}$) can be used in a hybrid cycle to produce electricity. This advantage is especially important because lower temperature geothermal resources are much more abundant than those with high temperatures. In a purely geothermal plant, low temperature fluids cannot produce power economically under present technology.

Because piping high temperature geothermal fluid over distances greater than 1.6 km (one mile) is impractical, the hybrid plant must be located within the geothermal resource area. In general, the geothermal resource is not optimally located with respect to sources of fuel, fresh water, or transmission networks. Therefore, while the thermodynamic advantage of the hybrid plant had been established, its economic competitiveness remained an open question. Could the economic advantages gained from the geothermal resource overcome the economic penalties owing to the location of the resource?

The Utilization Technology Branch (UTB) of the Energy Research and Development Administration (ERDA) undertook the task of determining the economic viability of a hybrid power plant. ERDA contract E(0-4-1311), "Site-Specific Analysis of Hybrid Geothermal/Fossil Power Plants", was awarded to the City late in 1976 and completed in the Spring of 1977. Pacific-Sierra, the major subcontractor to the City, was assigned the analytical modeling.

Study Objectives

The objectives of this work are:

- Develop the analytical techniques for rough parametric design of hybrid geothermal/fossil fuel plants for various geothermal resource characteristics
- Develop the analytical techniques for approximate evaluation of hybrid geothermal/fossil fuel plants for given hydrothermal resource characteristics, fossil fuel location, consumer locale, plant size, and environmental restraints

- Evaluate the merits of a hybrid geothermal/fossil fuel plant for each of four known geothermal resource areas (KGRA's):
 - Roosevelt Hot Springs, Beaver County, Utah
 - Coso Hot Springs, Inyo County, California
 - East Mesa, Imperial County, California
 - Long Valley, Mono County, California
- Prepare a preliminary plan for implementing geothermal energy in hybrid cycle plants.

The City assembled a team to achieve these objectives primarily from the staff of its Public Service Department (Figure ES-1). The objectives were achieved through the following task sequence:

- Execute the basic hybrid power plant synthesis
- Analyze the geothermal characteristics of each of the four KGRA's
- Conduct a site-specific analysis of power production and delivery
- Prepare preliminary plant designs optimized for each site
- Compare the optimized plant designs against each other and a reference coal-fired plant design
- Compile the report.

Study Criterion

Utilities strive to provide electrical energy to their customers at the lowest practical cost. Therefore, the selected criterion for this study is to establish minimum cost of delivered electrical energy through optimizing the use of coal and geothermal resources within environmental constraints and legal requirements. All regulations presently known, including environmental protection, safety, and water usage, are to be met. Throughout the study, care also is taken to ensure that performance characteristics are readily achievable within the current state-of-the-art.

The site-to-site cost comparisons are made by the general costing method outlined in ERDA 76-141, "Comparing New Technologies for the Electric Utilities," December 1976. The economic assumptions conform to the ERDA method.

Figure ES-1. - Project organization

Focus on Coal

By focusing on coal as the fossil fuel, this study recognizes the Nation's goal to reduce its dependence on oil and natural gas. A hybrid geothermal/coal plant would use two energy sources of great abundance within the United States. Its electrical power would be secure and reliable, immune from any gas shortage or oil embargo.

Another important attribute of coal is its status as the least expensive of the fossil fuels. Because oil and gas are more costly, geothermal energy in a hybrid cycle will show even greater savings than in the use of coal alone.

Because minimum cost of electrical power is the study criterion for the design of a hybrid plant, a reference all coal-fired plant is needed in order to provide:

- A standard for measuring the economic viability of the hybrid plant
- A guide for the costing of major power plant components.

Ideally, the reference plant should be a state-of-the-art design and optimally sited.

The Intermountain Power Project (IPP) plant was selected as the all coal reference. This plant is to start power production in 1984, which corresponds to the time period a hybrid plant could be ready for operation. Therefore, the IPP and the hybrid plants would face similar requisites relative to federal, state, and local regulations; cost of land, components, and labor; environmental restraints and requirements; and market considerations. The preliminary design of the IPP plant is available to the City because of its participation in the design study. The preliminary design for the IPP plant has not been completed at this time, although the work has been in progress since July, 1974, and considerable analyses have been made on the design.

Results and Conclusions

Site Evaluation

The energy cost comparisons of a 750 MW hybrid plant at each of the four

geothermal sites is presented in Figure ES-2. The principal conclusions drawn from the comparisons are:

- The Roosevelt Hot Springs site has the potential of producing electrical energy delivered to Burbank at 10 percent less cost than a well-sited reference all coal-fired plant.
- The Coso Hot Springs site shows slightly greater cost than the all coal-fired plant for delivered electrical energy to Burbank.
- The East Mesa and Long Valley sites did not show economic advantage for hybrid plants.

Although comparisons were not explicitly made between hybrid and all coal-fired plants located at Coso Hot Springs, East Mesa, or Long Valley, the hybrid plant would be competitive with any all coal-fired plant at the same site.

Figure ES-3 shows why Roosevelt Hot Springs and Coso Hot Springs are more competitive than either East Mesa or Long Valley. With fewer geothermal wells, hybrid plants at Roosevelt Hot Springs and Coso Hot Springs would reduce the coal requirement. For example, the amount of coal could be reduced by at least 46.3 t/hr (51.0 tons/hr) at Roosevelt Hot Springs. East Mesa and Long Valley have larger cost penalties owing to their greater distance from the coal source.

Cost Results

Table ES-1 shows the annual costs based on the ERDA costing method. The cost of coal delivered to the geothermal site is the principal economic factor that impacts upon the cost of delivered electrical power from the hybrid plant. In comparison, well cost and well O and M are less than five percent of the coal costs for each of the four sites; and they are roughly equal to the cost of cooling water. These data indicate that feedwater heating is indeed a most significant application of the geothermal fluid, by its replacement of coal.

Additionally, using the geothermal fluid to dry coal or to supply power to an auxiliary boiler would further increase its ability to replace coal. Further savings would result if the geothermal fluid is used to supply cooling water.

- 1 = Cost of power based on IPP estimating methods (Table 4-3)
 2 = Base year (1976) annual costs (Table 4-4)
 3 = Average annual costs based on ERDA costing method (Table 4-2)

Figure ES-2. - Energy cost comparisons for a 750 MW hybrid plant

Figure ES-3. - Energy input for a 750 MW hybrid plant

Fig. 11

TABLE ES-1. - AVERAGE ANNUAL COSTS FOR A 750 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley		All-Coal Roosevelt	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital	11.548	2.0664	11.652	2.0850	12.588	2.2525	12.299	2.2009	12.019	2.1507
Plant O and M	11.778	2.1076	11.806	2.1127	13.045	2.3344	12.502	2.2373	11.880	2.1258
Well Cost	0.325	0.0581	0.352	0.0630	0.347	0.0621	0.723	0.1294	-----	-----
Well O and M	1.035	0.1853	1.035	0.1853	1.138	0.2037	2.435	0.4357	-----	-----
Coal	64.781	11.5925	101.210	18.1114	113.616	20.3314	119.759	21.4306	76.917	13.7642
Cooling Water	1.298	0.2322	1.737	0.3109	0.770	0.1378	1.392	0.2491	1.166	0.2086
Total	90.765	16.2421	127.792	22.8683	141.504	25.3219	149.110	26.6830	101.982	18.2493
Transmission		2.94		1.24		1.78		2.63		3.12
Common Cost	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28
Cost of power (at Victorville)		20.46		25.39		28.38		30.59		22.65

• based on ERDA costing methods

It should be noted that well costs do not include royalties or profits, as they cannot be reliably estimated. If royalties or profits are large enough, they could affect site selection.

The capital cost of geothermal wells, larger condenser, and turbine-generator is more than offset by the reductions in the capital cost of the boiler for an all coal plant. At Roosevelt Hot Springs or Coso Hot Springs, the cost of a hybrid plant would be slightly less than the cost of an equivalent size all coal-fired plant. The development cost of the geothermal resource in East Mesa or Long Valley would more than cancel the reduced cost of the boiler.

Hybrid Plant Design

A well-designed and sited hybrid power plant can produce electricity at a lower cost than either a conventional coal-fired plant or an all geothermal plant. Several performance characteristics of the hybrid plant account for its economic viability:

- Geothermal energy could economically contribute more than 20 percent of the total energy consumed in a hybrid plant.
- The hybrid plant would utilize geothermal energy far more efficiently than present concepts for future all geothermal plants. For high-quality geothermal resources, the utilization of geothermal energy is about 20 percent greater. For marginal resources, the utilization efficiency can be one-and-one-half times to twice as great. Thus, the hybrid cycle would be especially useful for marginal geothermal sites located near enough to coal deposits to be economically viable.
- The thermodynamic efficiency of the coal contribution to electrical power production in a hybrid plant is only slightly less than that of the best all coal-fired plant.

These conclusions were reached notwithstanding two major design restrictions as well as some lesser ones imposed on the hybrid plant for this analysis. First, the geothermal energy was used only to heat the feedwater before it entered the boiler. Second, the boiler feedwater was heated in a subcritical cycle. Present judgment is that an actual hybrid design would encompass the following features:

- In addition to feedwater heating, the geothermal energy could have other applications, including:
 - coal drying and beneficiation

- o air preheating
 - o flue gas reheating
 - o auxiliary boiler heating
 - o general heating
- The water balance in a hybrid plant is such as to allow for complete consumption of the geothermal fluid in evaporative cooling wherever the chemical and local environmental conditions would allow
 - The restriction to a subcritical cycle holds the steam at just below the critical temperature and pressure. It appears that a supercritical cycle could be utilized, with maximum pressures of about 240 bars (3500 psia)
 - More than one turbine extraction point probably would be used. This allows flexibility to accommodate variations in the geothermal resource, as well as for high temperature steam for auxiliary station equipment. The hybrid plant is designed to accommodate some well shut-downs.

In view of the above considerations, the hybrid plant shows even greater promise than that revealed in the present study. Moreover, all the components in the hybrid cycle are state of the art. The use of coal ensures a guaranteed plant life even if the lifetime or quality of the geothermal resource is over-estimated.

Recommendations

The results of this present study and the Brown University study show that the hybrid cycle can combine the two abundant national resources, coal and geothermal energy, to advantage. The general recommendation is to design, construct, and operate one or more hybrid power plants at suitable geothermal sites as soon as practicable. An operational target date of 1984 would be a good goal. Supporting recommendations are given below:

Site Selection

Depending on the results of further field exploration and reservoir testing, it may be desirable to construct a hybrid plant at Roosevelt Hot Springs or Coso Hot Springs. Other geothermal resource areas also may merit serious evaluation as hybrid sites. Therefore, recommended site-selection

efforts include:

- Determination of the testing needed to validate the suitability of the geothermal sites for hybrid plants
- Verification of the reservoir temperatures and production flow rates for significant periods of time
- Evaluation of reservoir size and lifetime in order to design for the best plant sizing and plant economics.

The investment required for a hybrid plant necessitates, insofar as possible, a thorough and accurate analysis of the reservoir characteristics.

Preliminary Power Plant Design

Preliminary design of the hybrid geothermal/coal power plant should commence as soon as possible in order to:

- Validate the parametric analysis of this study
- Arrive at a preliminary optimum system design.

As a first design step, preliminary bid specifications should be developed for a hybrid plant to be constructed at Roosevelt Hot Springs or Coso Hot Springs. The bid specifications should be reviewed by architectural and engineering (A & E) firms, vendors, and other consultants to assure an adequate final system design.

To support the preliminary design effort, the parametric study should be extended to include:

- Supercritical cycles, as these show promise of more efficient geothermal energy utilization
- Off-peak cycles, whereby boiling is performed by the geothermal fluid and only superheating is supplied by the coal (i.e., 85 percent geothermal energy and 15 percent coal energy)
- Auxiliary uses of geothermal energy, such as coal drying and power plant cooling.

Environmental Studies

Some of the preliminary information required for the Environmental Impact

Assessment Report (EIAR) and the Environmental Impact Report (EIR) has been acquired during this study. Of special importance has been the attentive examination of several alternative sites for a hybrid plant. However, considerably more information needs to be obtained. An EIAR/EIR for the selected site must be completed in accordance with the "Guidelines to the Preparation of Environmental Reports for Geothermal Development Projects" (ERHQ-001), prepared by ERDA/DGE.

Development of New Coal Mines

For full load operation of a plant over 100 MW, it is anticipated that new mines will have to be developed. This will require time as well as investment by coal companies. Very early in the planning stage for actual construction of a plant, firm commitments for coal supply should be made -- possibly including advance cash payments -- to assure that coal will be available when the plant is ready.

Comprehensive Planning and Management Structure

Major delays and perhaps plant cancellations have resulted in recent years because the management structure was inadequate. A management plan should be developed to administer the many complexities, including financing, governmental relations, subcontractor relations, and community relations. Comprehensive planning should commence as soon as possible to assure proper timing and integration of all the activities needed to complete the hybrid plant. Of particular importance in the planning will be:

- An accurate analysis of the cash flow and source of funds
- Predesign and procurement of components, which often requires long lead times
- Satisfying all applicable local, State and Federal laws and regulations.

Geothermal Handbook

The methodology, results, and conclusions should be incorporated into ERDA's geothermal conversion handbook. Many geothermal resources which under present technology cannot be economically utilized could contribute to the hybrid concept.

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SECTION 1

THE HYBRID GEOTHERMAL/COAL PLANT

1.1 Theoretical Considerations

By analyzing the thermodynamic behavior of a hybrid plant, DiPippo, Kestin, and Khalifa described the theory by which the economics of a hybrid plant can be estimated. Accordingly, much of this first section uses excerpts from their report, "Hybrid Fossil-Geothermal Power Plants", which was written for ERDA under the auspices of Brown University. [1] (See Appendix F.)

1.1.1 The Economic Figure of Merit, F_e

Because a hybrid system utilizes two energy sources, each of which could be used individually in a state-of-the-art plant, the performance of a hybrid system should be evaluated in comparison with the highest efficiency achieved by the two individual sources. The situation is illustrated schematically in Figure 1-1 in which a hybrid system is contrasted with two individual conventional systems; a state-of-the-art fossil-fuel steam power plant, F^* , and a projected state-of-the-art geothermal plant, G^* . The fossil plant receives an amount of fossil heat, Q_f , and produces work W_f^* while operating at an efficiency $\eta_f^* = W_f^*/Q_f$. Similarly, the geothermal plant receives an amount of geothermal heat Q_g and produces work W_g^* at an efficiency $\eta_g^* = W_g^*/Q_g$. On the other hand, had the two heat inputs Q_f and Q_g been utilized in the hybrid plant, an amount of work, W , would have been obtained at an efficiency η :

$$\eta = W/(Q_f + Q_g). \quad (1)$$

This defines a thermodynamic figure of merit F which determines whether the hybrid system produces more or less work than the two separate systems; namely,

$$F = W/(W_f^* + W_g^*) \quad (2)$$

Separate Systems

Hybrid System

Figure 1-1. - Hybrid system contrasted with a separate fossil system and a separate geothermal system.

Obviously, the aim is to choose a hybrid system for which the thermodynamic figure of merit, F , is greater than unity. By introducing the geothermal heat fraction,

$$\phi = Q_g/Q_f, \quad (3)$$

and using Equation (1) along with the definitions of η_f^* and η_g^* , F becomes

$$F = (1 + \phi) \eta / (\eta_f^* + \phi \eta_g^*) \quad (4)$$

The quantities ϕ , η and η_g^* are functions of the temperature T_g to which the working fluid can be heated by means of the geothermal fluid. Equivalently, η and η_g^* are functions of ϕ which, in turn, is a function of T_g .

$$F(\phi) = (1 + \phi) \eta(\phi) / [\eta_f^* + \phi \eta_g^*(\phi)], \quad (5)$$

$$\phi = \phi(T_g) \quad (6)$$

A realistic assessment of the hybrid plant must allow for differing unit costs for Q_f and Q_g . This can be achieved by introducing the geothermal heat equivalence factor, ξ , which is the unit cost of geothermal heat divided by the unit cost of fossil heat. In general, ξ reflects the costs due to well and piping requirements, brine salinity, and environmental restraints associated with the geothermal resource. On the other hand, the heat equivalence factor ξ can also reflect savings due to the use of the geothermal fluid for auxiliary heating, as in coal drying. The savings would tend to make ξ smaller while increasing the hybrid plant efficiency, η .

Using ξ allows a more economically realistic figure of merit, F_ξ , to be defined as

$$F_\xi = (1 + \phi) \eta / (\eta_f^* + \xi \phi \eta_g^*) \quad (7)$$

Although F_ξ reflects the quality of the geothermal resource, it does not reflect the cost advantages or penalties due to the site location. In general, the cost of delivered fuel will be higher for a hybrid plant than for a well-sited all coal-fired plant. The cost of transmission and cooling water may be higher, even though the geothermal fluid might provide much of the cooling water. Special environmental factors, such as high seismicity, may also add

penalties to the cost. The payment on plant capital (as opposed to the capital used in geothermal field development) may be higher or lower than that of an all coal-fired plant. Further, ξ does not account for the plant capital savings due to the geothermal resource.

All of these considerations can be aggregated in the site-specific cost factor, γ , allowing the economic figure of merit, F_e , to be defined as

$$F_e = \gamma(1 + \phi) \eta / (\eta_f^* + \xi \phi \eta_g^*). \quad (8)$$

The factor γ can often be far more significant than the heat equivalence factor ξ . A high cost for delivered coal would tend to reduce both ξ and γ . However, ξ only influences the term $\phi \eta_g^*$ in the denominator of Equation (8), while γ acts on the entire expression. Hence, a small ξ usually cannot overcome the adverse effect of a small γ . Therefore, the geothermal resource location penalty must not greatly increase the cost of coal or transmission if it is to support a successful hybrid plant.

The economic figure of merit F_e will be determined for each of the four KGRA's studied. A value of F_e equal to or greater than 1.0 indicates that a hybrid plant for a specific site has economic promise. If F_e is less than 0.8, a successful hybrid plant is questionable.

1.1.2 Optimization Criterion

In deriving the economic figure of merit, F_e , an important question arises: What is the most appropriate optimization criterion for the hybrid plant?

One possibility is a criterion that minimizes coal consumption. If this criterion were adopted, then the important parameter would be the thermodynamic figure of merit F . Emphasis would be on optimizing the geothermal heat fraction and the hybrid plant efficiency.

However, a hybrid plant at its thermodynamic optimum may be far removed from its cost optimum. In terms of the economic figure of merit, F_e , the hybrid plant may have maximized the geothermal heat fraction ϕ at the expense of the

heat equivalence factor ξ , and the site-specific cost factor γ . Such a plant would be unattractive to utilities because they strive to provide electrical energy to their customers at the lowest practical cost. Consequently, the selected criterion used in this study is minimum cost of delivered electrical energy through optimizing the use of coal and geothermal resources within environmental restraints and legal requirements. Thus, all regulations presently known, including environmental protection and safety, are to be met. Throughout the study, care also was taken to ensure that performance characteristics were achievable within the current state of the art and conformed to modern engineering practices.

1.1.3 The Hybrid Plant Economic Dependence on a Geothermal Resource

The economic advantages of the hybrid system result from the amount of heat per unit time the geothermal fluid can deliver to the feedwater or auxiliary system. This, in turn, depends on the fluid mass flow rate and enthalpy change through the heat exchanger. The change in enthalpy does not depend on the number of wells or the collection pipe work. The rate of flow, however, does depend on these items, and thus the cost to increase the flow rate could be economically unrealistic. An appropriate parameter would, therefore, be the cost per well of providing a unit rate of flow.

Figure 1-2 shows, in a general way, how the cost of power (mills/kWh) from a cost optimized hybrid plant would vary with the geothermal fluid temperature ($^{\circ}\text{C}$) and the per well flow cost (\$/kg/hr). The region of interest is that part of the surface which lies below the plane representing the power cost of a reference all coal-fired plant, optimally sited. Ideally, the reference plant should approximate a state-of-the-art plant F^* , with efficiency η_f^* , as closely as possible.

The cost surface is site specific, and, therefore, depends upon coal cost and salinity of the geothermal fluid, as well as many other factors. In general, it will vary with the temperature and unit flow rate cost as shown on Figure 1-2. As the well capital and operating and maintenance (O and M) costs are a small fraction of the total hybrid plant costs, the power cost can be

Figure 1-2. - Cost surface for a particular geothermal site

estimated to follow a linear function of the cost per unit flow rate. However, the cost impact of temperature varies in a nonlinear and more significant fashion. For low geothermal temperatures, there is little value to the geothermal heat and hence, little effect on the cost of power. For high temperatures, however, the cost of power can drop dramatically.

In terms of the Brown University parameters used to derive F_e , high geothermal fluid temperatures will yield larger values of ϕ , η , and η_g^* . For a given geothermal fluid temperature T_g , the cost per unit flow rate is directly proportional to ξ , the geothermal heat equivalence factor. Therefore, the axis representing the cost per unit flow rate can also be considered as the axis representing ξ .

For a given site, ξ and T_g can be imagined to vary over a wide range of values. For each pair of coordinates (T_g , ξ) a cost optimized hybrid plant can be designed with an appropriate ϕ , η and η_g^* . Each site, of course, will have some particular ξ and T_g and thus will be represented as a point on the cost surface.

Note, however, that the cost surface for each site has a fixed value of γ , the site-specific cost parameter. Although γ does not affect the shape of the cost surface, it does affect its height. Therefore, some sites will be so unfavorable (small γ) that the cost surface will be below the cutoff plane even for very high values of T_g , and very low values of ξ . Other sites may be so favorable (large γ) that the cost surface will lie below the cutoff plane even for small T_g and large ξ . For a given site, T_g , ξ , and γ may vary with time. Figure 1-2 represents the variation in T_g and ξ by a region surrounding a point that represents the initial site coordinates. Moving the cost surface toward or away from the cutoff plane would represent the variation of γ with time. Ideally, the site location and geothermal resource is so favorable that moderate variation in γ , ξ , or T_g would not destroy the cost competitive status of the hybrid plant.

For a given geothermal temperature at a particular site, a definite minimum

flow rate is required. This minimum flow rate will entail some cost, and this in turn establishes a particular cost per unit flow rate. The question then arises as to whether or not an increase in the mass flow rate could be achieved at a lesser unit cost. For some sites this will be true; for other sites, the minimum required flow rate may also be the optimum flow rate. Before considering the optimum and minimum required flow rates, however, certain assumptions about the geothermal resource should be understood.

1.2 The Geothermal Resource

1.2.1 Temperature, Pressure and Flow Rate

The analysis of the geothermal resource is predicated, in part, on the following assumptions:

- The geothermal resource is represented by flowing hydrothermal wells
- The downhole fluid is a saturated liquid at the resource temperature and pressure
- The flow rate varies as the square root of the available pressure difference. To avoid choked flow, a limitation is imposed on the flow rate so that the pressure drop is one-third of the downhole pressure. Therefore, the pressure at the surface (P_s) is two-thirds of the downhole pressure (P_{dh}).
- To create the needed pressure difference for fluid flow, the temperature profile is assumed to allow some fraction of the fluid to flash to steam. This assumption is considered conservative because factors other than flashing can create a pressure difference.
- The heat of vaporization of the steam at the well head due to flashing is considered unavailable to the power plant.
- At the surface, the flow rate ($\dot{m}$) is estimated to vary also as the square root of the pressure difference. Saturated conditions also are used for feedwater heating using geothermal heat.

From the supporting data for this report, estimates of the downhole temperatures (T_{dh}) and pressures (P_{dh}) at each site are made. [2]. Assumptions for the allowed pressure drops and temperature profiles permit an estimate of the surface temperatures (T_s) and pressures (P_s). The well flow rate ($\dot{m}$) for Roosevelt Hot Springs, 454 t/hr (1000 klb/hr), is the basis for estimating

constants used to calculate the flow rates at the other three sites. Table 1-1 lists the geothermal resource parameters.

1.2.2 Quality and Heat Transfer

Information on fluid quality from the four sites indicate that the amount of total dissolved solids could vary from a few hundred to a few tens of thousands of milligrams per liter, mg/l. Values, however, should center in the few thousands of mg/l range. [2]

If present in large enough concentrations, dissolved solids could introduce significant corroding and scaling to the casing, well-head equipment, piping, and heat exchanger systems. Consideration of these effects in detail is beyond the scope of this study; however, it is necessary to approximate the degradation of heat exchanger performance. Thus, a value for the overall heat transfer coefficient of $U = 1227 \text{ (W/m}^2 \cdot \text{K)}$ ($U = 225 \text{ Btu/hr} \cdot \text{ft}^2 \cdot ^\circ\text{F}$) was assumed. This is less than half the typical value and has the effect of more than doubling geothermal feedwater heat exchanger costs. [3] The annual O and M for the geothermal feedwater heat exchangers were taken to be 8 percent of capital cost as compared to 4 percent for heat exchangers normally used in fossil power plants. The O and M costs of a geothermal feedwater heater are, therefore, in effect more than four times that of a typical heat exchanger.

1.2.3 Optimum Flow Rate

Along with the temperature of the geothermal fluid, the total flow rate from the resource determines the geothermal heat contribution to a hybrid plant, and thus influences the cost of power. Figure 1-3 shows in a qualitative way how the flow rate varies with the cost of power for a particular geothermal site. Before any geothermal fluid can be utilized, a minimum level of field development and increased plant complexity is incurred. Because this entails a cost beyond that of an all coal-fired plant that could be located at the site, a certain minimum flow rate must be achieved to make the hybrid plant competitive. (This flow rate will be estimated shortly.)

As the flow rate increases, the geothermal field is used to greater

TABLE 1-1.— SITE-SPECIFIC GEOTHERMAL RESOURCE PARAMETERS

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
T_{dh} , °C (°F)	274 (525)	260 (500)	200 (392)	177 (350)
P_{dh} , bar (psi)	58.5 (848)	47.0 (681)	15.6 (226)	9.3 (135)
$T_s = 0.92 T_{dh}$, °C (°F)	249 (480)	246 (475)	182 (359)	160 (320)
$P_s = 0.67 T_{dh}$, bar (psi)	39.0 (565)	31.3 (454)	10.3 (150)	6.2 (90)
$\dot{m}$, t/hr (klb/hr)	454 (1000)	406 (896)	234 (515)	181 (398)

Figure 1-3. - Optimum flow rate for a hybrid plant at a particular geothermal resource

economic advantage until a certain minimum cost of power is reached. This minimum cost may allow the hybrid plant to compete with an optimally sited all coal-fired plant. However, if the flow rate is too high, the reservoir may be depleted too quickly. Also, the cost of additional field development may begin to outweigh any advantages of the increased flow rate.

Therefore, there is an optimum flow rate for a given geothermal site. For some sites, the optimum flow rate will be insufficient to render the cost of power competitive with an all coal-fired plant. Other sites will be competitive even for flow rates that are far from optimum. The major uncertainty is the effect of flow rate on reservoir lifetime. Unfortunately, for the present, it is difficult to assess reservoir capacity, and hence, reservoir lifetime, until the producing field has been utilized for a period of time.

1.2.4 Derivation of Minimum Average Flow Rate

As Figure 1-4 indicates, the temperature and flow rate of each individual well generally differs from those of other wells. The temperature and, of course, the flow rates also will vary with time. To account for this, an additional parameter $\dot{m}_0$ is introduced. This is the minimum average mass flow rate, $\dot{m}_0$, which is necessary for the geothermal fluid to be competitive with coal. Although a detailed analysis could determine $\dot{m}_0$ precisely, it can be estimated based on several basic considerations.

If C_f is the cost per ton of delivered coal and each ton of coal yields roughly 23 MBtu, the cost per MBtu coal is simply $C_f/23$. In view of this cost, a question arises, then, as to the maximum cost, C_g , of a MBtu of delivered geothermal energy. Clearly, $C_f/23$ and C_g are related by ξ , the geothermal heat equivalence factor (see Section 1.1):

$$C_g = \xi \cdot C_f/23 \quad \$/\text{MBtu} \quad (9)$$

The answer, therefore, becomes one of determining a maximum value for ξ , or $\xi_{\max}$. This quantity is given by:

$$\xi_{\max} = \bar{\eta}_g^0 / \bar{\eta}_f^0 \quad (10)$$

Figure 1-4. - General profile of temperatures and flow rates over time for a geothermal resource

As given in the Brown University report, $\bar{\eta}_g^0$ is the available efficiency of the geothermal fluid and is based upon only its surface temperature (T_s), reject temperature (T_r), and sink temperature (T_o):

$$\bar{\eta}_g^0 = 1 - T_o \ln (T_s/T_r) / (T_s - T_r) \quad (11)$$

Thus, no entropy losses within the power plant are taken into account. The term $\bar{\eta}_f^0$ is the available efficiency of coal and is assumed to be 0.62.

The following example may reveal the reasoning behind Equation (10). Suppose the geothermal fluid can be used only half as efficiently as coal. Then twice as many MBtu's of geothermal energy are needed to supply the same amount of useable energy as coal. To be competitive with coal, the cost per MBtu of geothermal energy must therefore be no more than half the cost per MBtu of delivered coal. Thus the maximum cost, C_g , of a MBtu of delivered energy becomes:

$$C_g = (\bar{\eta}_g^0 / \bar{\eta}_f^0) \cdot (C_f / 23) \text{ \$/MBtu.} \quad (12)$$

Having ascertained C_g , the MBtu requirement for each well can be determined. The cost of each well, including its associated piping, is noted as C_w . It is assumed that 0.5 percent of C_w is the monthly payment on the capital investment. To account for well and piping maintenance, an additional 1.5 percent per month is applied. The well-replacement requirement adds another 0.5 percent per month. Therefore, the monthly well cost is estimated to be 2.5 percent of C_w , or $\frac{C_w}{40}$. Because there are 720 hours in a 30-day month, the cost per hour due to the wells and piping is:

$$(3.472 \times 10^{-5}) C_w \text{ \$/hr.} \quad (13)$$

This cost is solely for the geothermal fluid. If the maximum cost per MBtu geothermal is C_g , then the minimum hourly MBtu requirement, $B_{\min}$, is:

$$B_{\min} = (3.472 \times 10^{-5}) (C_w / C_g) \text{ MBtu/hr.} \quad (14)$$

Assuming that the specific heat, C_p , of the geothermal fluid at constant pressure is roughly 1.0 Btu/lb. °F, the minimum average flow rate $\dot{m}_o$ is:

$$\dot{m}_o = \frac{10^3 B_{\min}}{(T_s - T_r)} \text{ klb/hr.} \quad (15)$$

By using Equations (12) through (15) $\dot{m}_o$ becomes,

$$\dot{m}_o = 0.80 \frac{C_w}{C_f} \cdot \frac{\bar{\eta}_f^o}{\bar{\eta}_g^o} \cdot \frac{1}{T_s - T_r} \quad \text{klb/hr} \quad (16)$$

If SI units are substituted for C_f (\$/t), T_s ($^{\circ}\text{C}$) and T_r ($^{\circ}\text{C}$), then the equation for $\dot{m}_o$ becomes,

$$\dot{m}_o = 0.22 \frac{C_w}{C_f} \cdot \frac{\bar{\eta}_f^o}{\bar{\eta}_g^o} \cdot \frac{1}{T_s - T_r} \quad \text{t/hr} \quad (17)$$

1.2.5 Minimum Flow Rates for the Geothermal Sites

The minimum acceptable mass flow rate $\dot{m}_o$ per well for each geothermal site, as well as the calculated flow rates $\dot{m}$, are shown on Table 1-2. Roosevelt Hot Springs, Coso Hot Springs, and the East Mesa KGRA have calculated flow rates exceeding the minimum flow rate by substantial margins, as indicated by the ratio $\dot{m}/\dot{m}_o$. However, the Long Valley KGRA has a calculated flow rate that is 80 percent of the required minimum flow rate. This suggests, on this basis, that the Long Valley KGRA is the least promising of the four sites considered. Although the estimates for $\dot{m}_o$ are approximate, they allow some initial generalization about the sites relative to hybrid cycle use.

According to Table 1-2, a higher price for delivered coal C_f results in a lower minimum flow rate $\dot{m}_o$. This is interpreted to mean that if coal, despite its higher cost, is burned at the site, then geothermal energy at a lower flow rate can compete with coal. Because Roosevelt Hot Springs would have the least expensive coal, its $\dot{m}_o$ is higher than that of Coso Hot Springs or the East Mesa KGRA. However, the Long Valley KGRA displays the highest $\dot{m}_o$ despite the fact it has the highest coal cost. This is because the difference between the temperatures of the incoming geothermal fluid and the reject fluid is so low as to more than offset the effect of the coal cost.

Table 1-3 shows the quantities $\bar{\eta}_g^o$, $\xi_{\max}$, ξ and $\xi/\xi_{\max}$ for each site. With the exception for the Long Valley KGRA, the value of ξ for each site is

TABLE 1-2. - COMPARISON OF $\dot{m}_o$ AND $\dot{m}$ FOR EACH SITE

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
C_w , \$ ¹	1 208 000	1 208 000	738 000	1 292 000
C_f , \$/t (\$/ton)	20.00 (18.00)	30.70 (27.90)	31.90 (29.00)	33.00 (30.00)
$\bar{\eta}_g^o / \bar{\eta}_f^o = \xi_{\max}^2$	0.45	0.45	0.32	0.29
T_s , °C (°F)	249 (480)	246 (475)	182 (359)	160 (320)
T_r , °C (°F)	81 (178)	83 (181)	57 (135)	58 (136)
$\dot{m}_o$, t/hr (klb/hr)	176 (395)	119 (262)	128 (283)	292 (646)
$\dot{m}$, t/hr (klb/hr)	454 (1000)	407 (896)	234 (515)	181 (398)
$\dot{m}/\dot{m}_o$	2.6	3.4	1.8	0.6

1. Includes reinjection well requirements and cost of collection piping.

2. $\bar{\eta}_g^o$ given by the equation $\bar{\eta}_g^o = 1 - \frac{T_s}{T_o} \ln \frac{T_s}{T_r}$, with T_o assumed to be 38°C (100°F)

$\bar{\eta}_f^o$ assumed to be 0.62

TABLE 1-3. - COMPARISON OF $\bar{\eta}_g^0$, ξ , AND $\xi_{\max}$ FOR EACH SITE

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
$\bar{\eta}_g^0$ (percent)	28	28	20	18
$\frac{\bar{\eta}_g^0}{\bar{\eta}_f^0} = \xi_{\max}$ ¹	0.45	0.45	0.32	0.29
ξ	0.13	0.10	0.13	0.24
$\xi / \xi_{\max}$ (percent)	29	22	41	83

¹ $\bar{\eta}_f^0$ assumed to be 62%

substantially below the allowed maximum, $\xi_{\max}$.

1.3 The Reference All Coal-Fired Plant

Because minimum cost of electrical power is the design criterion for the hybrid plant, a reference all coal-fired plant is needed in order to provide:

- A standard for measuring the economic viability of the hybrid plant
- A guide for the costing of major power plant components.

Ideally, the reference plant should be a state-of-the-art design and optimally sited.

1.3.1 Selection of the Reference Plant

The Intermountain Power Project (IPP) plant was selected as the all-coal reference. This plant is to start power production in 1984, which corresponds to the time period a hybrid plant could be ready for operation. Therefore, the IPP and the hybrid plants would face similar requisites relative to federal, state, and local regulations: cost of land, components, and labor; environmental restraints and requirements; and market considerations. The preliminary design of this plant is available to the City because of its participation in the IPP design study. Although the preliminary design for the IPP plant has not been completed at this time, the work has been in progress since July, 1974 and considerable analyses have been made on the design.

The IPP generating station is to be located 16 miles northwest of Hanksville, Wayne County, Utah. (See Figure 1-5.) The generating station is to consist of four 750 MW net steam electric generating units (820 MW rated). Each unit uses 2 585 500 kg (5 700 000 lb) of steam per hour at a pressure of 171.6 bar (2475 psig) and a temperature of 540°C (1005°F). Each unit will burn 352 t/hr (388 tons/hr) of pulverized coal (wet weight) full capacity, at a heating value of 22.45 kJ/kg (9655 Btu/lb). The net heat rate for the full plant at maximum load is presently 10 540 kJ/kWh (9990 Btu/kWh). [2]

Figure 1-5. - Location of proposed IPP plant

1.3.2 IPP History and Present Status

In 1957, the Intermountain Consumer Power Association (ICPA) of Sandy, Utah, organized for hydroelectric supply. However, in 1970 they were notified that additional hydroelectric power would no longer be available. Thus, coal became the alternative. In 1971, the first applications for water in southern Utah were filed for use in a power plant. Other utilities were contacted, and after considerable analysis and study the IPP project was formed on January 18, 1974. In July, 1974, the participants in the program signed the membership agreement and work began on siting and design of the IPP all coal-fired plant.

The participants in the IPP plant study and their ownerships are:

Intermountain Consumer Power Association (Utah and Nevada)	15.0%
City of Anaheim (California)	15.0%
City of Burbank (California)	2.5%
City of Glendale (California)	2.5%
City of Los Angeles (California)	50.0%
City of Pasadena (California)	5.0%
City of Riverside (California)	10.0%

The Preliminary Engineering and Feasibility Study for the IPP plant has been completed. The final report was prepared in October, 1976, and has been issued to all participants. A participation agreement is being finalized for the design and construction phase of the plant and should be ratified before January, 1978. Environmental impact statements and water development studies are in progress.

1.3.3 Restriction of Hybrid Plant Capacity to 250 MW and 750 MW

Plant generating capacities under consideration should assure reliable comparison with the reference plant. As an upper limit, 750 MW was chosen which is the net steam capacity of one IPP generating unit. As a lower limit, 250 MW was chosen which is the generating capacity of the City's present power plant. It is most unlikely any new power plant using coal would have a lesser capacity. In any case, the 250 to 750 MW range assures that only plants compatible with available markets and conventional practices will be considered.

Figure 1-6 diagrammatically represents the hybrid plant and the IPP reference plant as black boxes with inputs and outputs. Only 250 MW and 750 MW hybrid plants were analysed. It is reasonable to expect both the geothermal heat fraction and the cost per kW to decrease as the generating capacity increases within the 250-to 750-MW range.

1.3.4 The Potential of Geothermal Energy Utilization in the Reference Coal-Fired Plant

Two significant factors must be considered in the potential use of geothermal energy in a hybrid cycle: the heat balance for the power plant and the auxiliary requirements for the overall plant. The latter would include general heating, coal drying and beneficiation, air preheating, and flue gas reheating. The ultimate effect of geothermal utilization is to reduce the fuel (coal) requirement, given a prescribed plant output or alternatively, geothermal utilization would permit a higher plant output, given a stated coal supply.

Figure 1-7 shows a heat balance diagram for the IPP plant for a 100 percent load, or 819 859 kW. (The average load would be 85 percent of the rated load of 750 000 kW, or 637 500 kW). Some of the geothermal sites can supply heat to the plant in excess of 249°C (480°F) and 34.5 bar (500 psi). Therefore, any uses of heat, at temperatures and pressures near or below these values, are subject to replacement by geothermal energy. Those plant auxiliaries falling within the category of potential replacement by geothermal are listed in Table 1-4. As the table indicates, the feedwater heaters use the major amount of extraction steam -- 743 919 kg/hr (1 640 033 lb/hr) as compared to 288 897 kg/hr (636 898 lb/hr) for the other units. Although some of these units do use steam higher than the geothermal temperature, they could be replaced with units designed to operate on lower temperature steam. This extraction steam represents a significant amount of the total energy supplied. Figure 1-8 shows that reducing extraction steam allows higher mass flows for each turbine stage.

Besides the energy withdrawn in extraction steam, a considerable amount of energy is supplied by an auxiliary boiler for various plant uses. (Table 1-5 lists the uses of the auxiliary low temperature steam.) The auxiliary

Power System Under Study

Reference All Coal-Fired Unit

Figure 1-6. - Summary figure reflecting fundamental guidelines

Figure 1-7. - Heat balance diagram for the Intermountain Power Plant

TABLE 1-4. PROPERTIES OF THE STEAM PROVIDING THE LOW TEMPERATURE ENERGY INPUT

Unit	Temperature		Pressure,		Volume		Enthalpy	
	°C	(°F)	bar	(psig)	kg/hr	(lb/hr)	10 ³ J/kg	(Btu/lb)
Air heater	380	(716)	12	(159)	27 216	(60 000)	3220	(1385)
Flue gas heater	380	(716)	12	(159)	63 504	(140 000)	3220	(1385)
Turbine (pump) #1	380	(716)	12	(159)	86 689	(184 500)	3220	(1385)
Turbine (pump) #2	380	(716)	12	(159)	85 304	(188 060)	3220	(1385)
Evaporator	380	(716)	12	(159)	29 184	(64 338)	3220	(1385)
Feedwater heaters:								
#7	247	(477)	39	(551)	201 581	(444 403)	3048	(1311)
#6	208	(407)	19.6	(270)	112 580	(248 192)	3360	(1445)
#5	184	(363)	12	(159)	88 498	(195 102)	3218	(1384)
#4	158	(316)	6.9	(85)	109 978	(242 456)	3067	(1319)
#3	119	(246)	2.9	(28)	70 605	(155 655)	2837	(1220)
#2	99	(210)	2.0	(14)	71 992	(158 713)	2720	(1170)
#1	77	(171)	1.4	(6)	88 684	(195 512)	2597	(1117)

Figure 1-8. - Turbine-stage steam-flow rates for fossil fuel and hybrid plants.

TABLE 1-5. - AUXILIARY LOW TEMPERATURE ENERGY

Steam temperature = 288°C (550°F), Pressure = 28.6 bar (400 psig)

Unit	Steam Flow	
	kg/hr	lb/hr
Building heating *	18 144	(40 000)
Generator pegging	27 670	(61 000)
Air ejector	454	(1 000)
Boiler feed pump turbine (25% load)	42 185	(93 000)
Boiler feed pump turbine seals	272	(600)
Included draft fan turbine *	52 618	(116 000)
Induced draft for turbine seals	272	(600)
Warm up main turbine	15 876	(35 000)
Main turbine seals	9 072	(20 000)
Coal handling *	16 330	(36 000)

* continuous use

boiler also could be replaced by geothermal energy. Costs associated with coal drying and other coal treatments also could be reduced through the use of geothermal energy. Because coal from the southern parts of the Wasatch Plateau can contain from four to 15 percent moisture, substantial amounts of energy use could be involved. A moisture content of 12 percent, and a coal consumption rate of 352 t/hr (388 tons/hr) is assumed for the coal to be used in the IPP plant. These figures imply that up to 43 t (47 tons) of water would have to be removed hourly. This effort would require 26.4 MW (90 MBtu/hr), or approximately 4.5 t (5 tons) of coal per hour. The equivalent heat from a geothermal source would require about one-third to one-half of the output of a geothermal well.

Another potential use of the geothermal resource is the reduction of the plant's requirement for cooling tower water. Flashed steam could provide water for the boiler feed.

1.3.5 Economic Assumptions

Table 1-6 shows the economic assumptions common to the four of the geothermal sites. To index plant costs, the costs for the IPP design are used as a base. Each of the major component costs in the hybrid plants is based on vendor data as function of power level, heat transfer area, or other appropriate factors and then indexed to the IPP component costs.

In making the site-to-site comparisons, common economic assumptions and component costs are used. The site-specific factors that varied are:

- Temperature of the geothermal resource
- Cost of coal
- Cost of makeup water
- Cost of electrical transmission
- Seismic factor
- Climatic parameters.

Except for seismicity and climate, all sites were considered environmentally

equivalent. Environmental costs were based on the IPP costs and integrated with other costs.

TABLE 1-6. - ECONOMIC ASSUMPTIONS COMMON TO THE FOUR SITES

- 2-year environmental assessment period
- 4-year construction period
- 30-year plant lifetime
- 85% plant utilization factor
- Costs are expressed in 1976 dollars and discounted for future utility and inflated for future costs.
 - Annual discount rate of 5%
 - Annual inflation rate of 5% for components, supplies and labor
 - Annual inflation rate of 8% for coal costs
 - Bond interest rate of 6% (typical for the City)
- IPP design is basis for major hybrid plant component cost estimates.

1.4 The Hybrid Cycle

1.4.1 Selection of an Appropriate Cycle

In modern steam power stations, cycle thermal efficiencies of 43 to 44 percent (i.e., $\eta_f^* = 0.43 - 0.44$) are achievable. This is made possible by using steam of high initial parameters, by the adoption of reheat and regenerative feedwater heating principles, and by systematically improving and efficiency of the individual components. The IPP reference plant has a design efficiency of 0.38.

A certain amount of fossil heat Q_f can always be utilized in such a state-of-the-art plant to produce work at an efficiency η_f^* . From an energy utilization viewpoint, any new system proposed for utilizing Q_f , either in part or in full, should at least do so as efficiently as a modern fossil-fueled steam power plant. This imposes certain limitations on the choice of the type of steam

cycle for a hybrid plant. A minimum efficiency of the hybrid plant may be calculated by assuming that the thermodynamic figure-of-merit F equals unity:

$$F = \frac{\eta^*(1+\phi)}{\eta_f^* + \phi\eta_g^*} = 1, \text{ or} \quad (18)$$

$$\eta_{\min} = \frac{\eta_f^* + \phi\eta_g^*}{(1+\phi)} = \eta_{\min}(\phi) \quad (19)$$

The fractional contribution, ϕ , of the geothermal source to the overall heat input is determined primarily by the geothermal fluid temperature T_g . In order to accommodate a geothermal fluid heat exchanger in the feed loop of the steam cycle, the final feedwater temperature should be lower than the geothermal fluid temperature. Modern high pressure steam power stations operate with feedwater temperatures as high as 300°C (572°F) whereas most liquid-dominated geothermal sources have well head temperatures considerable lower than 300°C (572°F). Consequently, it is almost always possible to find a cycle arrangement compatible with a particular geothermal site.

The existence of a lower limit of efficiency, $\eta_{\min}$ as implied by Equation (18), suggests that the choice of a cycle for the hybrid system is not arbitrary. Table 1-7 shows how $\eta_{\min}$ varies with increasing ϕ , the geothermal heat fraction. Even for values of ϕ as high as 0.4, $\eta_{\min}$ deviates little from the efficiency of the reference plant. This suggests that suitable cycles should approach the efficiency of state-of-the-art steam power cycles. If the hybrid cycle is made similar to state-of-the-art cycles, then much of the technology can be readily used. Hence, it is convenient to make the hybrid cycle quite similar to that of an all coal-fired plant.

However, if a cycle identical to the state-of-the-art cycle is initially used, replacement of some regenerative feedwater heating with geothermal heating represents a thermodynamic penalty. This is attributable to the fact that regenerative feedwater heating is responsible for a significant portion of the improvement in the efficiency of modern steam cycles over the basic Rankine cycle. Consequently, cycles that derive all their efficiency improvement from

TABLE 1-7. - VALUES OF MINIMUM ACCEPTABLE HYBRID PLANT EFFICIENCY, $\eta_{\min}(\phi)$, VERSUS
SELECTED VALUES OF THE GEOTHERMAL HEAT FRACTION, ϕ

$\eta_{\min} = \frac{\eta_f^* + \phi \eta_g^*}{1 + \phi}$	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
$\eta_g^*{}^1$	20%	20%	14%	13%
$\eta_f^* = \eta_{\min}(\phi = 0) {}^2$	38%	38%	38%	38%
$\eta_{\min}(\phi = 0.1)$	36%	36%	36%	36%
$\eta_{\min}(\phi = 0.2)$	35%	35%	34%	34%
$\eta_{\min}(\phi = 0.3)$	34%	34%	32%	32%
$\eta_{\min}(\phi = 0.4)$	33%	33%	31%	31%

${}^1 \bar{\eta}_g^* = 0.7 \times \bar{\eta}_g^0$ for each site

${}^2 \bar{\eta}_f^* = \text{IPP plant efficiency} = 0.6 \times \bar{\eta}_f^0$

regenerative feedheating will suffer the highest thermodynamic penalty in a hybrid arrangement. Theoretically, this penalty could negate the advantages of the hybrid concept. However, modern steam cycles have only one or two reheat stages and use only seven or eight feedwater heaters. This practical requirement limits the extent of the thermodynamic efficiency penalty for coal usage incurred in a hybrid arrangement, and results in a wide range of conditions under which a gain can be realized (i.e., the thermodynamic figure of merit F is greater than one).

Table 1-8 presents the calculated optimum values of the geothermal heat fraction, ϕ_{opt} , and the hybrid plant efficiency, η_{opt} , for each site. As can be seen, the value of η_{opt} at each of the four geothermal sites exceed the minimum required efficiency η_{min} as given by Equation (18). Therefore, a thermodynamically viable hybrid cycle is achievable at each site. Because the optimum value of ϕ reflects only the use of the geothermal fluid for feedwater heating, the efficiency of an actual hybrid plant could be expected to exceed those presented in Table 1-8.

1.4.2 Thermodynamic Assumptions

Figure 1-9 presents the basic hybrid cycle. (Appendices A through D contain T-S diagrams for the hybrid cycle at each site. The Brown University report (Appendix F) also contains generalized T-S diagrams.) The hybrid cycle differs principally from the conventional power plant cycle in the hybrid plant use of geothermal fluid to replace some of the extraction steam used for feedwater heating. The number of geothermal feeds depends, of course, on the temperature of the geothermal fluid.

For each site, a thermodynamic cycle was selected that minimized the cost of power for the proposed 750 MW and 250 MW plants. The hybrid cycle analyzed in this report does not use geothermal fluid for any application other than feedwater heating. In view of these considerations, the following assumptions were made:

- Subcritical Steam Cycle. Because the IPP plant utilizes a subcritical steam cycle, and the available water equations-of-state do not adequately describe a supercritical cycle, the site comparisons used a subcritical

TABLE 1-8. - COST-OPTIMIZED VALUES OF THE GEOTHERMAL HEAT FRACTION, ϕ , AND HYBRID PLANT EFFICIENCY, $\eta(\phi)$, AS COMPARED WITH THE MINIMUM ACCEPTABLE HYBRID PLANT EFFICIENCY, $\eta_{\min}(\phi)$

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
ϕ_{opt}	20.7%	19.2%	14.7%	11.7%
$\eta_{\text{opt}}(\phi_{\text{opt}})$	35.6%	35.6%	36.1%	36.6%
$\eta_{\min}(\phi_{\text{opt}})$	34.9%	35.1%	34.9%	35.4%

Figure 1-9. Basic hybrid cycle

cycle with a maximum fluid pressure of 203 bars (2947 psia). In the course of the cycle optimizations, it became apparent that the cost optimum for the plant should, in fact, incorporate a supercritical steam cycle. Although a supercritical cycle would slightly increase the geothermal contribution and reduce lifetime costs, it would not change the conclusions of the site-to-site comparisons.

- Single Reheat. The IPP plant incorporates a single reheat cycle. While the cycle calculations did not investigate the possibility of double reheat, the indication is that the economic optimum only would have a single reheat. The analysis also indicates that hybrid cost optimization would tend to occur when reheat enthalpy was somewhat less than the amount normally used.
- Maximum Steam Temperature. The IPP plant incorporates a high pressure turbine that uses steam with an inlet temperature of 538°C (1000°F). Using cost algorithms, including appropriate turbine cost penalties for higher temperature, the hybrid cycle calculations always optimized at the highest allowable turbine inlet temperature. Based on current practice, which considers turbine maintenance, and in conformance with the IPP indexing, a maximum steam temperature of 540°C (1004°F) was used in the cycle optimizations.
- Single Bleed. Wide latitude is available in the number of extraction points for drawing bleed steam from a given turbine without seriously affecting plant efficiency or cost. Because the geothermal fluid would provide most of the condensate and feedwater heating, it is assumed that absolute capital cost variation would not depend strongly on slight variations in the number of extraction points used. [4] For simplicity, all of the bleed steam in the hybrid plant would be used solely to heat feedwater to temperatures above those achievable by the use of the geothermal fluid. Extraction steam flow and enthalpy drop were optimized to minimize the cost of power. In general, it appears that a single extraction minimizes the hybrid plant complexity at little or no cost penalty. The resulting analytical cycle representation is shown in Figure 1-10.

The model did not consider the use of additional extraction steam in a condensate deaerating contact heat exchanger, or for plant auxiliary steam. For the following two reasons, these were not considered: First, auxiliary-steam demand fluctuates too much for adequate computer modeling. Second, the analysis indicates that auxiliary-steam usage would not vary from site to site. To provide a realistic description of performance at various sites, each facility was penalized on overall performance by a factor consistent with the penalty incurred by the existing IPP design for its use of auxiliary steam.

- Heat Losses. The IPP cycle uses a turbine with an efficiency of 90 percent. In the hybrid cycle calculations, an overall turbine efficiency of only 85 percent is assumed for dry steam, and a somewhat lower percentage for wet steam. This severely penalized the hybrid

Figure 1-10. Analytical hybrid cycle

plant compared to IPP. However, for tractability in the hybrid plant optimization, the analysis neglected heat losses other than heat rejection in the condenser and stack-exit flue gas as well as the cycle effect of the many unwanted steam bleeds and leaks of an actual plant. In comparing the hybrid to the IPP plant, the assumptions approximately balance out. In the site-to-site comparisons, the effects are believed to be negligible.

- Condenser Pressure. The IPP plant uses a minimum condensing pressure of 0.097 bar (1.4 psia). For the cycle analysis calculations, this value is used as a lower parameter limit; in all cases, the economic optimum plant required a condenser pressure at this minimum limit.

Rather than the somewhat idealized plant design used for these site-to-site comparisons, present judgment is that an actual optimized hybrid plant constructed today would:

- Use a supercritical steam cycle with maximum pressures of about 240 bar (3500 psia)
- Have an overall turbine efficiency approaching 90 percent and
- Use more than one turbine steam-extraction point, primarily for flexibility to accommodate variations in the geothermal resource, and to provide steam capacity for auxiliary station equipment.

SECTION 2

PLANT SITING

2.1 The Geothermal Sites

As has been noted previously, the economics of a particular hybrid plant must be evaluated with respect to a specific site. This report considers four KGRA's of varying resource characteristics, climate, seismology, geography, and other environmental factors. (See Figure 2-1):

- Roosevelt Hot Springs, Beaver County, Utah
- Coso Hot Springs, Inyo County, California
- East Mesa, Imperial County, California
- Long Valley, Mono County, California

Figure 2-2 presents the major plant siting factors. Initially, of course, there must be an adequate geothermal resource capable of sustained production to justify a hybrid plant. Although data on lifetime resource capacity are not available at this time, the temperature, pressure, and flow rate data given in Section 1 suggests that the four sites deserve serious consideration as sites for a hybrid plant. However, key siting considerations must be addressed before an economic judgment can be attempted:

- The availability, quality, and cost of coal
- The availability of water
- The availability of transmission.

If any of these factors present a major restraint, the hybrid plant, in all probability, could not be economically viable.

Figure 2-1. - Location of the four KGRA's considered in this study

Figure 2-2. - Major plant siting factors

The environment of each of the chosen KGRA's impacts the hybrid plant, and the plant, in turn, impacts the environment. Separate sections are devoted to seismological and climatic factors. While environmental and socioeconomic concerns are recognized to be of crucial importance, they were not addressed in this study. Rather, attention is focused upon sites which could economically support a hybrid plant. Except for seismicity and climate, all sites were considered environmentally equivalent. Environmental costs were based on the IPP costs and integrated with other costs. It is interesting to note that all of the sites except Long Valley are at least 64.4 km (40 miles) away from national parks or monuments. (Long Valley lies 32.2 km (20 miles) east-southeast of Yosemite National Park.)

An environmental assessment is, of course, the first step that must be taken once a promising hybrid site is identified and selected. At that point the full EIAR/EIR process should be employed.

Information on the plant siting factors is also presented in the supporting information sections to this report which contain considerable geological detail on the four KGRA's studied.

2.2 COAL

2.2.1 California Coal

Although there are small but measurable coal resources in California, this study will disregard California coal for the following reasons:

- Studies indicate that California coal is high in sulfur content - two to three percent - and hence probably unsuited for power plant use because of air pollution constraints. Costs of installation for sulfur removal equipment are prohibitively high on a per kilowatt basis
- There is presently no coal production in California from which to gain operating experience.
- California coal occurs in small deposits in hilly country near highly desirable or densely populated land, making environmental considerations complex and unpredictable. Costs of establishing a mine or local regulations may prohibit production.

2.2.2 Arizona Coal

The Arizona Black Mesa coal deposit occurs within the Navajo reservation, and has been developed in cooperation with the Navajo Tribe specifically for the Navajo Power Plant at Page, Arizona. New transportation facilities for any further development of these mines would be required as this coal generally is not being marketed elsewhere. Environmental concerns for both mining and transportation development in this area are severe. It is unlikely that coal would be available from this source at a lower cost than coal expected to be available from the Wasatch-Emery or Kaiparowits areas, in view of the greater distance coupled with lack of transportation facilities.

2.2.3 Wyoming Coal

Wyoming deposits are extensive and coal is presently being mined and shipped to eastern electric utility markets, as is Utah coal. There is the possibility that additional strip mining may make large quantities of low cost coal available. However, because of existing transportation arrangements and competition from Utah mines, it appears that this coal would be shipped east rather than west. Other strip mines could be developed on the Great Plains but existing coal rail lines go east. Coal transportation westward from Wyoming would pass through the Utah coal areas and rail usage would be in competition with Utah coal.

2.2.4 Utah Coal

Possible sources of coal available for the four KGRA sites with distances to the sites in airline miles, are shown in Table 2-1.

Utah coal, either from the Wasatch-Emery area or the Kaiparowits areas, appears to be a relatively convenient source for all the sites, especially for Roosevelt Hot Springs. (See Figure 2-3). Further, it can be assumed that coal for a future plant may come from mines as yet not constructed, or from portions of coal fields not presently mined. Utah coal from the Wasatch-Emery and Kaiparowits areas has been extensively analyzed as part of the preparatory studies for the Kaiparowits Power Plant and the IPP. Hence, coal data are readily available. Also, these coal areas have been developed, in part, for

TABLE 2-1. - AVAILABILITY OF COAL TO FOUR KGRA SITES

KGRA Site	Nearest Possible Coal Source	Second Nearest Possible Source	Third Nearest Possible Source
Roosevelt Hot Springs	Utah, Wasatch-Emery, 100 miles	Utah, Kaiparowits, 150 miles	Wyoming, 250 miles Arizona, Black Mesa, 250 miles
Coso Hot Springs	Utah, Kaiparowits, 300 miles	Utah, Wasatch-Emery, 500 miles Arizona, Black Mesa, 500 miles	Wyoming and New Mexico 600 miles
East Mesa	Utah, Kaiparowits, 400 miles Arizona, Black Mesa 400 miles	Utah, Wasatch-Emery, 600 miles	Wyoming, 700 miles
Long Valley	Utah, Kaiparowits, 300 miles	Utah, Wasatch-Emery, 500 miles Wyoming, 500 miles	Arizona, Black Mesa, 600 miles

Figure 2-3. - Principal coal deposits in Utah

planned power plants, existing local plants and other markets. Therefore, the relatively small amounts of coal required for the hybrid plant undoubtedly will be available at low cost.

2.2.5 Selection of Wasatch-Emercy Coal

This study utilizes coal specifications derived for IPP from reports on the Wasatch-Emercy coal fields. Data on the Kaiparowits coal fields are essentially identical. The Wasatch-Emercy coals are preferred to that of Kaiparowits because

- Wasatch-Emercy coal is more readily available. At present, the northerly portion of this field is being mined extensively and the amount of coal deposits is comparable to, perhaps larger, than Kaiparowits.
- There are existing rail lines that serve the Wasatch-Emercy field. No rail lines, as yet, serve the Kaiparowits area
- Anticipated environmental constraints at Kaiparowits may not allow development of this field
- Kaiparowits coal is generally of lower quality than that of Wasatch-Emercy coal before washing. Washing to bring Kaiparowits coal up to the quality of Wasatch-Emercy coal will increase relative costs.

Average coal quality values from existing Wasatch-Emercy mines have been used in all the design calculations. Composite Wasatch-Emercy coal values for IPP are:

Heating Value	Sulfur Content	Ash Content
26 860 kJ/kg (11 560 Btu/lb)	0.56%	8.10%

The current base cost for coal is \$16.50 per tonne (\$15 per ton) loaded on trucks at the mine mouth. Transfer to rail cars, rail shipment, truck shipment, and unloading at the site are additional costs. An analysis of these costs for each site is presented below.

2.2.6 Delivered Coal Cost for the Four Sites

Roosevelt Hot Springs. - Because of the proximity of Roosevelt Hot Springs

to the Wasatch-Emerly area (see Figure 2-3), coal could be most advantageously shipped by truck. The nearest probable coal delivery is Salina, Utah, approximately 160 kilometers (100 miles) by highway. The probable maximum distance by truck would be 320 kilometers (200 miles), which would place the delivery point in the center of Utah mining community at Carbonville. (See Figure 2-4.) Because of recent highway construction, truck shipment rates of 1.1 million tonnes (1.0 million tons) per year are presently contemplated. Based on average distance, the shipping cost is \$6.00 per tonne (\$5.50 per ton). With coal at \$16.50 per tonne (\$15.00 per ton), coal costs at Roosevelt are \$22.50 per tonne (\$20.50 per ton) for small plant sizes, 50 to 100 MW, or for startup or test purposes.

Future shipments by rail of larger coal quantities may lower the relative cost, even though the existing rail route is much longer. For extremely large coal shipments, a study would be required to determine if a specially constructed dedicated coal railroad would further reduce relative costs, especially if future oil price increases make costs of electric rail transit more attractive than that of diesel truck. For quantities of coal for a 750 MW plant the cost of shipping could range from \$1.70 to \$3.50 per tonne (\$1.54 to \$3.18 per ton), depending upon the actual distance within the 160-to-320 kilometer (100-to-200-mile) range. Cost of delivered coal would then be between \$18.20 and \$20.00 per tonne (\$16.50 to \$18.00 per ton). Figure 2-5 shows the price of coal for various annual requirements.

Coso Hot Springs. - Delivery of coal to Coso Hot Springs is assumed to be by rail; presumably, environmental and traffic control considerations would preclude shipment by truck when rail facilities are available. (Figure 2-4.) It is assumed that an existing rail spur serves the KGRA site and that rail-cars belong to the railroad company. No costs are included for unloading facilities or labor.

For small plant sizes, 50 to 100 MW, or for startup and test purposes, a firm rate for coal shipments from the Southern Pacific Transportation Company (SPTC) is \$24.90 per tonne (\$22.60 per ton). With base cost of coal at \$16.50 per tonne (\$15.00 per ton), the total cost is \$41.40 per tonne (\$37.56 per

Figure 2-4. - Coal shipment routes

Figure 2-5. - Cost of coal versus rate of coal consumption

per ton) delivered.

For coal deliveries required by a 750 MW plant, the extrapolated cost is \$14.20 per tonne (\$12.88 per ton) plus \$16.50 per tonne (\$15.00 per ton) base cost, or \$30.70 per tonne (\$27.90 per ton) of coal delivered.

East Mesa KGRA. - Delivery of coal to East Mesa also is assumed to be by rail; presumably, environmental and traffic control considerations would preclude shipment by truck when rail facilities are available. (See Figure 2-4.) It is assumed that an existing rail spur serves this site and that railcars belong to the railroad company. No costs are included for unloading facilities or labor.

For small plant sizes or for startup and test purposes, a firm rate for coal shipments from SPTC is \$27.70 per tonne (\$25.13 per ton) plus \$16.50 per tonne (\$15.00 per ton) base cost, or \$44.20 per tonne (\$0.10 per ton) of coal delivered.

For coal deliveries required by a 750 MW plant, an extrapolated delivery cost is \$15.40 per tonne (\$13.97 per ton) plus \$16.50 per tonne (\$15.00 per ton) base cost, or \$31.90 per tonne (\$29.00 per ton) delivered. (See Figure 2-5.)

Long Valley KGRA. - Shipment of coal to Long Valley is assumed to be by rail as far as Mina, Nevada, then by truck 130 kilometers (81 miles) to Long Valley. (See Figure 2-4.) Because the shipping route crosses northern Nevada, the winter cold may cause the coal to freeze in the rail cars and complicate unloading into trucks. For the quantities of coal required by a 750 MW plant, extension of the rail line to the plant site would probably prove feasible. No costs are included for unloading coal at the plant. Rail cars are assumed to belong to the rail company and trucking is assumed by private contractor.

For small plant sites, 50 to 150 MW, or for startup and test purposes, a firm rate is \$21.00 per tonne (\$19.05 per ton) to Mina, Nevada, plus \$5.50 per

tonne (\$5.00 per ton) for trucking, plus \$16.50 per tonne (\$15.00 per ton) base cost, or \$43.00 per tonne (\$39.09 per ton) delivered. (See Figure 2-5.)

For coal deliveries required by a 750 MW plant, it is assumed that a rail line will be constructed to the plant site. The cost of delivered coal is thus extrapolated to be \$16.50 per tonne (\$15.00 per ton) base cost plus \$16.50 per tonne (\$15.00 per ton) delivery cost, or \$33.00 per tonne (\$30.00 per ton).

An alternate delivery route would involve taking delivery of coal at a railhead near Lone Pine, California, and then shipping it by truck to the plant site. This route is considered less advantageous than the Mina route because:

- Rail shipment to Lone Pine is longer and higher in cost
- Trucking route from Lone Pine to Long Valley is longer and through environmentally more sensitive country
- Trucking route is scenic highway and subject to very heavy traffic during vacation season
- Heavy competition for use of existing land and right-of-way makes possibility of rail line extension very remote.

Based on the coal cost information presented, Table 2-2 gives the coal cost per joule (Btu) and the mills per kWh coal for hybrid plants of differing size. Table 2-2 also shows the required amount of coal for each site, given the plant size, assumed heat rate, and an assumed plant factor of 85 percent. Those figures applying to the 250, 500, and 750 MW hybrid plants are of special interest.

2.3 Water

2.3.1 Water Requirements

The consumption of water by an all coal-fired power plant is controlled by the makeup water required for the turbine exhaust condensing system. This system requires the disposal of nearly 2.30×10^6 J/kg (1000 Btu/lb) of steam

TABLE 2-2. - FUEL COST ESTIMATE DETAIL BREAKDOWN AND COMPARISON

Plant size, MW*	Assumed heat rate, 10^6 Joules/kWh (10^3 Btu/kWh)	10^{15} Joules/year (10^{12} Btu/year) from coal***	Coal*** 10^3 tonnes/year (10^3 tons/year)	Coal cost*** 10^{-10} \$/J (10^{-7} \$/Btu) Mills/kWh fuel **			
				Roosevelt	Coso	East Mesa	Long Valley
50	10.6 (10.0)	3.36 (3.17)	125 (138)	8.0 7.0 (8.4)	13.2 11.9 (13.9)	13.9 12.5 (14.6)	13.9 12.5 (14.6)
100	10.5 (9.9)	6.65 (6.27)	248 (273)	7.7 6.9 (8.1)	12.5 11.2 (13.2)	13.0 11.6 (13.7)	13.2 11.8 (13.9)
250	10.5 (9.9)	16.63 (15.67)	619 (682)	7.5 6.6 (7.9)	11.5 10.3 (12.1)	11.9 10.7 (12.5)	12.4 11.0 (13.0)
500	10.5 (9.9)	33.25 (31.37)	1238 (1364)	7.4 6.6 (7.8)	11.4 10.2 (12.0)	11.9 10.6 (12.6)	12.3 11.0 (13.0)
750	10.5 (9.9)	49.88 (47.02)	1857 (2047)	7.4 6.6 (7.8)	11.4 10.2 (12.0)	11.9 10.6 (12.6)	12.3 11.0 (13.0)
1000	10.5 (9.9)	66.5 (62.7)	2475 (2729)	7.4 6.6 (7.8)	11.4 10.2 (12.0)	11.9 10.6 (12.6)	12.3 11.0 (13.0)
750 100% Coal at IPP site	10.5 (9.9)	58.7 (55.3)	2184 (2408)	7.4 7.8 (7.8)			

*Total plant output including geothermal contribution; coal figures based on 85% coal contribution.

**based on net MWh, including "free" geothermal contribution

***based on 0.85 plant factor derived from postulated loading of 100% for 85% of the year and 0% for 15% of the year.

exhausted by the turbine. A typical steam plant rejects most of this waste heat to the atmosphere usually by means of a wet cooling tower. Other workable methods of waste heat rejection consist of the wet/dry cooling tower, the dry cooling tower, the spray pond, the non-spray lagoon, and various combinations employing local bodies of water or rivers.

Among these methods, all consume water except the dry cooling tower which depends on large and costly water-to-air indirect heat exchangers in which the water does not contact the air. The other methods use direct contact with the atmosphere to exchange the waste heat. The direct contact aspect is the root cause of water consumption inasmuch as a large fraction of the heat is exchanged by the evaporation of the warm water. In a wet cooling tower, up to about 85 percent of the heat is rejected by evaporation with the remainder of the heat rejection dependent on conductive heat exchange and drift losses.

The turbine exhaust cooling water consumption is further dependent on the isentropic expansion efficiency of the turbine and the isentropic change in enthalpy for each pound of turbine steam flow. For a high temperature, high pressure turbine of the type proposed in the IPP study, an isentropic efficiency of 75 to 90 percent and an isentropic enthalpy change of 1.51×10^6 J/kg (650 Btu/lb) of turbine steam flow are assumed. Thus, the cooling water makeup requirement, W_m , in lb/hr may be calculated from

$$W_m = \frac{(\text{evaporation fraction}) \cdot (\text{output, watts}) \cdot (3.413 \text{ Btu/W hr})}{(\text{isentropic enthalpy change, Btu/lb steam}) \cdot (\text{isentropic efficiency})} \quad (20)$$

It is estimated that the IPP Plant, at an 85% plant capacity factor, would require 41.2×10^6 cubic meters (33 400 acre feet) of cooling makeup water per year which corresponds to an evaporation fraction of 0.70, an isentropic efficiency of .90, and an isentropic enthalpy change of 1.5×10^6 J/kg (650 Btu/lb) of steam. This amounts to 13.73×10^3 cubic meters (11.13 acre feet) per year per net MW.

Other water requirements are estimated to be:

	<u>Acre-feet</u> MW Year	<u>Cubic meters</u> MW Year
Plant O and M community	.37	456
Scrubber evaporation	1.35	1665
Ash and sludge disposal	.19	234
Waste water and miscellaneous losses	.40	393
Reserve	1.83	2257
	<u>4.14</u>	<u>5005</u>

If a plant cycle is used in which the geothermal fluid is flashed to produce steam, there may be a net production of water over that consumed in the cooling tower. The amount of this excess will vary with the resource temperature. For example, water at 177°C (350°F) could yield about 18.50×10^6 cubic meters (15 acre feet) per year per net megawatt from this source. The amount of fluid which can thus be permanently removed from the reservoir must consider that which is required for subsidence control.

2.3.2 Possible Sources of Water

Water for cooling towers and makeup for the hybrid plant can be obtained from several possible sources depending on the particular location of each KGRA: ground water, the Los Angeles Aqueduct, or agricultural return water. Of course, spent geothermal water or steam would be available to all four geothermal sites.

If geothermal fluid is flashed to yield steam, which is then either condensed to produce water or is expanded through a turbine or other engine to yield work, a useful amount of relatively high quality water can result. If the fluid is flashed at atmospheric pressure, from about 10 to 25 percent of the hot water will appear as steam (depending on the initial water source temperature) which can be condensed to water. If the geothermal fluid is flashed at temperatures close to those proposed for the steam turbine exhaust condensing temperature than about twice as much water will be produced. If the flashed fluids product steam is used to drive an auxilliary turbine or

engine the amount of produced water would be less than either of the above cases. However, because of the energy extracted by the turbine, there would be less heat to be rejected from the condensate and there could well be more pure water available to the system.

2.3.3 Water Availability in Utah

Roosevelt Hot Springs. - Water rights in Utah are based on appropriation. The first Party using the water has first right to the water, no matter for what purpose the water is used. As of December 1, 1976, the Roosevelt Hot Springs area has been closed to appropriation. However, water for cooling towers might be available in one or more of the following ways:

- Purchase an existing water right and petition the State Engineer for change of use
- Import water from outside the Milford Valley watershed
- Discover a new source of ground water and petition the State Engineer to appropriate additional waters in the area.

Water quality of ground water in the Milford area varies with depth and location, with the better quality water occurring in the southern part of the area at depths below 76 meters (250 feet). Because the general ground water flow is to the north, the waters at the northern end of the valley contain a higher concentration of dissolved solids due to residual salts, a result of irrigation processes, evaporation, and transpiration.

2.3.4 Water Availability in California

Coso Hot Springs. - Coso Hot Springs KGRA is within the Rose Valley watershed of Inyo County. This geothermal area is arid owing to an average rainfall of less than seven inches per year. Rose Valley is recharged by local rainfall and runoff from the Sierra Nevada to the west and the recharge is estimated to be between 12.3 to 24.7 million cubic meters (10 to 20 thousand acre-feet) per year.

Water for cooling purposes in this area can be obtained from:

- Mine water from the Rose Valley Basin. It is estimated that about 9,864 million cubic meters (8 million acre feet) of pore space exists in the basin. There is some agriculture in the area with prior rights and their use would have to be protected.
- Use the annual runoff less that used by local agriculture. This could provide between 9.9 and 19.7 million cubic meters (8000 and 16 000 acre feet) annually.
- Purchase water from the City of Los Angeles and construct a pipeline from the Los Angeles Aqueduct to the power plant. This water could be replaced by purchase of Metropolitan Water District (MWD) water for Los Angeles at any point along the MWD system in the City of Los Angeles.

Water quality from runoff and the Los Angeles Aqueduct are essentially the same.

East Mesa. - There are two possible sources of water for cooling purposes in the East Mesa area:

- Colorado River water purchased from the Imperial Irrigation District (IID).
- Agricultural return water from the New or Alamo Rivers.

Colorado River water could be obtained in either of two ways. Water could be purchased directly from IID. The District has indicated that it would supply water to San Diego Gas & Electric for a proposed geothermal plant at Heber with the stipulation that IID participate in the capacity of the power plant. It is assumed that a similar arrangement probably would apply in the East Mesa area. However, the supply of water without participation by IID could be accomplished by allowing IID to take Colorado River flow assigned to the Metropolitan Water District of Southern California and paying for only the transport charge. The nearest available surface water to East Mesa would be the East Highline Canal on the west edge of East Mesa.

Agricultural return water could possibly be available from the New or Alamo Rivers. Both rivers discharge into the Salton Sea and the quality at discharge apparently is acceptable for cooling purposes.

Long Valley. - Water rights in the Owens River watershed are vested in

the City of Los Angeles. The City could furnish water for a power plant under several conditions. One would be an exchange of water with the City of Burbank. Los Angeles would furnish water in Long Valley and Burbank would furnish water to Los Angeles from Burbank's MWD allotment. The cost of MWD water is currently \$68.13 per thousand cubic meters (\$84 per acre-foot) and the cost undoubtedly will rise sharply when power contracts are renegotiated in the early 1980's. However, if the City of Los Angeles participates in the development of geothermal power in Long Valley because of their fee ownership, it is possible that they would furnish the necessary waters without demanding any reciprocation from the City of Burbank.

The water from the Owens River watershed, because it is low in total dissolved solids, suggests that several cycles of water use could be possible before disposal.

2.3.5 Water Disposal

Ideally, the fluid disposal system should return the spent liquid to its original source in a quality that would not degrade the source, either for its initial use or for reasonable subsequent use.

Low quality waste water from certain plant processes and from the plant community would be treated in a conventional sewage disposal facility with secondary effluent being placed in a holding pond for observation and further treatment, if necessary, and then returned to the aquifer or receiving stream. Any dissolved solids recovered in the treatment plant would be combined with the spent geothermal fluids for injection. The waste and wash water from the demineralizer regeneration cycle would be segregated and added to the holding pond of pH adjustment prior to injection.

Sewage sludge along with the SO₂ scrubber sludge would be disposed in the sludge pit.

The final method of fluid and sludge disposal will depend on the compatibility of the receiving streams and aquifers to the materials to be disposed.

2.4 Transmission

2.4.1 Considerations Common to All Four Sites

New transmission paths will be required to bring the bulk of plant output to the Los Angeles area. The new plant is conceived as a base load plant, and firm transmission must be available to allow for such operation. Existing transmission facilities in all transmission corridors are heavily loaded or committed. However, in some cases, firm wheeling arrangements should permit the transmission of 50 to 200 MW to the Los Angeles area over existing facilities with minor, low-cost modifications. In other situations, new transmission lines contemplated in connection with other large power generation projects could be increased in capacity to transmit the additional power. For larger plants, generally, the full construction costs of new transmission lines must be borne. Existing transmission lines may offer nonfirm, off-peak, or emergency backup transmission capacity which could reduce the redundancy normally required in new lines for reliable operation.

Bulk transmission lines will terminate at or near the Victorville Substation of the Los Angeles Department of Water and Power. This is the Southern California regional delivery point for this study. Victorville lies on a reasonably direct transmission route from all proposed sites, with minimum potential environmental complications. All four geothermal sites are in relatively uninhabited areas and the probable transmission corridor to the Los Angeles area also would be in relatively uninhabited areas.

Flexible transmission arrangements, including interties and wheeling agreements, should be considered in order to meet the following situations:

- The plant could begin operation as a pilot plant, with plans to expand to a full-size plant contingent on operating experience gained at lower output levels
- The plant could be constructed in stages with the in-between delays to allow for design optimization based on operating experience
- The main project-owned transmission lines may be delayed in construction owing to design difficulties, construction problems, or environmental litigation.

In each of these eventualities, it would be advantageous to market the power over a temporary transmission path which is to be superseded at a later date by project-owned facilities. Also, interties with local utilities should be considered for other reasons:

- A nonfirm intertie wheeling path agreement could provide limited back-up in the eventuality that the project-owned transmission lines are out of operation for a time
- Displacement operation, where power generated in Utah is utilized in Utah while power which would normally be imported into Utah is sent to Southern California instead, may reduce total losses, and presupposes an intertie operation agreement
- A Utah source of power intertied with the state power system can improve the reliability of the local power system, an additional compensation to Utah residents for permitting the plant and its lines to be built in their community
- The plant will require construction power from the local power supply system. If the supply station is planned with any eventual intertie operation in mind, redesign and reconstruction can be minimized.

Electric switchyard costs are the same for each site. (Table 2-3). The costs of project-owned transmission lines represent reasonable estimates of costs of transmission under the most likely circumstances. Intertie contract operation is unlikely to reduce these costs. Transmission concepts based on interconnections, and/or joint-use facilities are discussed in the supporting information sections of this report.

2.4.2 Construction Power for the Four Sites

Construction power for a hybrid project at Roosevelt Hot Springs would presumably come from Utah Power and Light 46 kV lines which exists on the property. During construction, testing, startup, and pilot operation, small amounts of generated power could conceivably be fed into the 46 kV system through this line also.

Construction power for a hybrid project at Coso Hot Springs would be furnished by the Southern California Edison Company (SCE) 115 kV lines in the area because the site of the plant is in the SCE service area. A hybrid

TABLE 2-3. - ELECTRIC SWITCHYARD CONSTRUCTION COSTS

(Common For All Sites)

Item	250 MVA 230 kV	750 MVA 345 kV
Site procurement and preparation	\$ 700 000	\$ 800 000
Fencing, buildings, and roads	200 000	300 000
Equipment foundations	300 000	400 000
Equipment structures	550 000	800 000
Electrical grounding system	180 000	300 000
Auxiliary power and control systems	1 150 000	1 800 000
Engineering, including field engineering	200 000	350 000
Miscellaneous	1 250 000	2 000 000
Main power transformer	1 500 000	3 200 000
Startup transformer	235 000	400 000
House transformer	500 000	1 300 000
Power circuit breakers	525 000	1 000 000
Disconnect switches	225 000	260 000
Miscellaneous power equipment	150 000	240 000
Total	\$ 7 665 000	\$13 150 000
Less, for main, house, and startup transformers and related equipment (plant components).	2 735 000	5 800 000
Net cost, switchyard only	4 930 000	7 350 000
Switchyard cost/kVa	\$ 19.72	\$ 9.80

project at East Mesa would draw its construction power from the existing 33-kV lines of the Imperial Irrigation District.

Construction power for a hybrid project at Coso or Long Valley may prove more difficult to obtain. Even though the sites lie in the service area of Southern California Edison Company, several miles of 115-kV transmission lines would have to be built to supply the construction power.

2.4.3 Base Case Transmission, Terminus to Terminus, for the Four Sites

For a 250 MW plant size, a base case approach has been estimated based on a single transmission circuit between the power plant switchyard and the Southern California regional delivery point. For the 750 MW plant, the base case was estimated for two lines. Table 2-4 shows construction cost estimates for the base case at each of the four sites. Figure 2-6 shows the base case line(s) routing for each of the four sites. Finally, Table 2-5 gives the expected base case transmission losses for each site.

2.5 Seismicity

Because the KGRA's under consideration are within areas of high seismicity, any proposed plant structures and/or transmission systems constructed in these areas could be subject to structural damage.

The data presented in this section is a general site review based on information obtained from published sources. Field geologic studies, exploratory borings or laboratory testing has not been initiated for this review nor has a specific site spectral response analysis been done for any of the KGRA's.

2.5.1 Criteria for Defining Active Fault

An active fault is defined by the California Council on Intergovernmental Relations in the General Plan Guidelines, September, 1974, as:

"... a fault that has moved in recent geologic time and which is likely to move again in the relatively near future. For geologic purposes, there are no precise limits to recency of movement or probable future movement that define an 'active fault'. Definitions for planning purposes extend

TABLE 2-4. - COST OF BASE CASE ELECTRIC TRANSMISSION, TERMINUS TO TERMINUS

	Line Length		250 MW	750 MW
	kilometers	(miles)		
Roosevelt Hot Springs				
Transmission Voltage			345 kV	(2) 345 kV
Roosevelt switchyard			\$ 7 350 000	\$ 7 350 000
Roosevelt-Paragonah line segment	82	(51)	6 375 000	12 750 000
Paragonah-McCullough line segment	304	(189)	23 625 000	47 250 000
McCullough-Victorville line segment	261	(162)	26 875 000	53 750 000
Victorville substation*			6 900 000	9 350 000
Total	647	(402)	\$ 71 125 000	\$ 130 450 000
Coso Hot Springs				
Transmission voltage			220 kV	(2) 345 kV
Coso substation			\$ 4 930 000	\$ 7 350 000
Coso-Victorville line	193	(120)	7 920 000	30 000 000
Victorville substation*			5 900 000	9 350 000
Total	193	(120)	\$ 18 750 000	\$ 46 700 000
East Mesa				
Transmission voltage			220 kV	(2) 345 kV
East Mesa substation			\$ 4 930 000	\$ 7 350 000
East Mesa-Devers line segment	191	(118)	7 788 000	29 500 000
Devers-Victorville line segment	117	(73)	4 818 000	18 250 000
Victorville substation*			5 900 000	9 350 000
Total	308	(191)	\$ 23 436 000	\$ 64 450 000
Long Valley				
Transmission voltage			345 kV	(2) 345 kV
Long Valley substation			\$ 7 350 000	\$ 7 350 000
Long Valley-Victorville line	445	(276)	34 500 000	69 000 000
Victorville substation*			6 900 000	9 350 000
Total	445	(276)	\$ 48 750 000	\$ 85 700 000

Nominal MWH/Year **

250 MW yields

750 MW yields

* Includes auto-transformer

-60-

1 861 500

5 584 500

** Assumes 85% plant factor

Figure 2-6. - Possible transmission corridors

TABLE 2-5. - TRANSMISSION LOSSES FOR BASE CASE, TERMINUS TO TERMINUS

Site, Distance to Victorville	MW/MVA Sent	MW Losses at Nominal Load	MWh/Year Losses *	Losses as % of Total Generation
Roosevelt Hot Springs, 647 km (402 mi)	250/300	17.4	129 500	7
	750/900	78.3	582 600	10
Coso Hot Springs, 193 km (120 mi)	250/300	12.6	94 100	5
	750/900	23.1	172 200	3
East Mesa 308 km (191 mi)	250/300	20.0	149 000	8
	750/900	36.7	273 600	5
Long Valley 445 km (276 mi)	250/300	11.8	87 900	5
	750/900	53.1	395 200	7

* Assumes 8760 hours/year, 85% plant capacity factor.

on the order of 10,000 years or more back and 100 years or more forward. The exact time limits for planning purposes are usually defined in relation to contemplated uses and structures."

On the other hand, the Atomic Energy Commission (1973), as a part of their geologic siting criteria for nuclear power plants, has defined a capable (active) fault as one which has exhibited one or more of the following characteristics: [5]

- Movement at or near the ground surface at least once within the past 35 000 years or movement of a recurring nature within the past 500 000 years
- Microseismicity instrumentally determined with records of sufficient precision to demonstrate a direct relationship with the fault
- A structural relationship to a capable fault according to the first two characteristics above such that movement of one could be reasonably expected to be accompanied by movement on the other.

The possibility of surface rupture or of larger earthquakes on a particular fault can, in principle, usually be determined from seismologic, geologic, and geodetic data, such as earthquake history, the distribution of epicenters, and the ages of displacements. However, in practice, all or part of the data are often completely lacking for almost all faults. In any event, faults which are active present a potential seismic hazard at least over the next 100 years.

2.5.2 Seismicity for California KGRA's

The seismic environment for the KGRA's situated in California is controlled by the following major active fault systems: The San Andreas fault extended from Humboldt County to the Salton Sea; the Garlock fault trending northeasterly from the San Andreas fault to Death Valley; and the Owens Valley and/or Sierra Nevada frontal fault system that extends northerly from the Garlock fault along the Sierra Nevada to the Nevada state line. As shown on Figure 2-7 these major faults with their associated secondaries have been historically active.

The map shown on Figure 2-8 is a portion of the state-wide map showing maximum credible rock acceleration for California. Each of the major faults

Figure 2-7. - Major California faults

Figure 2-8. - Maximum credible rock acceleration from earthquakes in California

shown was assigned a maximum probable earthquake (see functional basis earthquake below) based on their lengths. The map represents a conservative estimate of rock acceleration to be expected along these major faults.

Although the occurrence, magnitude, and location of future seismic events cannot be accurately foretold, a sufficient number of seismic events of magnitude 6.0 or greater have occurred in the general area of the KGRA's that similar events could be expected during the life of the proposed power plant structures. Locations of known active faults along which future movement will most likely affect East Mesa, Long Valley, and Coso Hot Springs KGRA's are shown on Table 2-6. Magnitudes and approximate epicenters of these faults are also shown.

Even without a detailed specific-site spectral-response analysis, a general guide to ground acceleration at or near the KGRA's may be considered based on the Schnabel and Seed (1972) graph of maximum acceleration versus distance derived for bedrock, and the Housner (1965) graph of maximum acceleration versus distance for deep firm alluvium (Figure 2-9). These general values have been assigned on the following basis: [6] , [7]

- The maximum credible earthquake, or the maximum probable included ground motion which may be expected at the power plant sites within the known geologic framework
- The functional basis earthquake, or the maximum probable induced ground motion which may be postulated with a reasonable confidence level within a 100-year period.

The accelerations shown on Table 2-7 should be considered as a general guide even though the curves derived by Housner lack recent data such as that for the 1971 San Fernando earthquake.

2.5.2 Seismicity for Utah KGRA's

Utah lies along the Intermountain Seismic Belt, a zone of pronounced earthquake activity that extends north from Arizona through Utah, eastern Idaho, and into western Montana. Most of Utah's recorded earthquakes have occurred along the boundary between the basin and range and the Colorado Plateau-Middle Rocky Mountain physiographic provinces. An active seismic zone

TABLE 2-6. - ACTIVE FAULTS NEAR KGRA SITES

Approximate Epicenter	Magnitude	Date	Approximate Distance KGRA (miles)	Fault System
East Mesa KGRA (lat 32°-45' N long 115°-15' W)				
32°-45' N/115°-28' W	7.1	5-19-40	13	Imperial
32°-57' N/116°-01' W	6.5	10-21-42	46	Agua Caliente
33°-18' N/116°-12' W	6.2	3-19-54	65	San Felipe
33°-28' N/116°-35' W	6.0	3-25-37	90	San Jacinto
Coso Hot Springs KGRA (lat 36°-04' N long 117°-50' W)				
35°-45' N/118°-05' W	6.3	3-15-46	26	Sierra Nevada
35°-15' N/118°-32' W	6.1	7-23-52	64	Kern Canyon
Long Valley KGRA (lat 37°-37' N long 118°-54' W)				
37°-35' N/118°-44' W	6.0	9-14-41	4	Sierra Nevada Fault
37°-30' N/118°-45' W	6.0	9-18-27	8	Sierra Nevada Fault

Figure 2-9. - Maximum ground acceleration versus distance from causative fault

TABLE 2-7. - MAXIMUM CREDIBLE EARTHQUAKE ACCELERATION

Fault System	Miles	Maximum Credible Earthquake				Functional Basis Earthquake	
	from	Acceleration (g) at Site				Acceleration (g) at Site	
	Site	Mag.*	Schnabel & Seed	Housner	Mag.	Schnabel & Seed	Housner
Long Valley KGRA							
Owens Valley	30	8.25	0.27	0.37	6.6	0.11	0.19
Mono Lake	18	6.0	0.14	0.18	6.0	0.14	0.18
Coso Hot Springs KGRA							
Garlock	44	7.75	0.15	0.22	6.0	0.05	0.08
Owens Valley	6	8.25	0.58	0.50	6.6	0.44	0.32
Panamint Valley	26	7.25	0.20	0.30	6.0	0.10	0.15
East Mesa KGRA							
Imperial	12	7.0	0.33	0.34	7.5	0.38	0.38
Agua Caliente	46	7.0	0.08	0.15	6.6	0.05	0.01
San Felipe Hills	56	7.5	0.10	0.18	6.6	0.05	0.08
Laguna Salada	36	7.25	0.17	0.24	6.0	0.08	0.11
San Jacinto	60	7.5	0.08	0.13	6.6	0.04	0.07
Sand Hills	10	7.5	0.43	0.40	7.0	0.40	0.35

* Based on maximum expected bedrock accelerations, Greensfelder, R., 1974.

- Notes: 1. The front faults along the Sierra Nevada and the White Mountains can be equated with the Owens Valley fault.
2. The Sand Hills fault is the extension of the San Andreas fault as mapped.

intersects this seismic belt northward from Cedar City (Figure 2-10).

The Sevier and Tushar fault zones (Figure 2-10) are the most active seismic areas of Utah. The historic seismic activity of the Roosevelt Hot Springs and Cove Fort areas of southwestern Utah shows a relatively low level when compared to these areas. However, five shocks with maximum estimated magnitude of 4.0^{+} occurred in the Beaver Lake Mountains 18 kilometers (11 miles) northwest of Milford in 1908. And, as late as 1966, an earthquake of magnitude 4.9 was located near the Milford area.

The Roosevelt Hot Springs area is within zone 3 as shown on the Uniform Building Code seismic risk map of the United States, and therefore, could experience an earthquake of magnitude 6.0^{+} . Because data shown on Figure 2-8 pertain only to California earthquakes, maximum acceleration data are not available for the Roosevelt Hot Springs area. However, effective peak acceleration of approximately 0.1 g is indicated for the KGRA on the seismic risk map of the California Applied Technology Council. [8]

2.5.3 Seismic Risk

Seismic factors (SF) account for any additional construction costs needed to enable plants to withstand significant damage due to maximum expected earthquakes. The SF factors for each site were based on a review of its seismicity and maximum credible ground acceleration. Power plant components were also considered.

<u>KGRA Site</u>	<u>SF</u>
Roosevelt Hot Springs	1.00
Coso Hot Springs	1.02
East Mesa	1.10
Long Valley	1.03

The SF factors multiply the base capital costs of the structure, handling equipment and cooling towers. It is assumed the other plant components would withstand maximum expected seismic events owing to their dynamic loading factors.

Figure 2-10. - Major fault zones of Southwestern Utah

2.6 Climatic Factors

The climatic factors considered, those that would affect power plant performance (excluding severe weather conditions), are ambient temperature and pressure, wet bulb temperature, and make-up cooling water temperature. Ambient and wet bulb temperatures are based on meteorological data obtained for the four KGRA sites and their surrounding areas. The values assumed for this study are 99-percentile values for periods of record; accordingly, they are significantly above expected values for each site. Average cooling-water temperatures for the sites are believed to vary from 21°C (70°F) in the winter to 29°C (85°F) in the summer. Therefore, a representative value of 27°C (80°F) was assumed for the calculations. Ambient pressures utilized in the calculations were based on site elevation data. [2] A summary of these climatic parameters is given below in Table 2-8.

TABLE 2-8. - CLIMATIC PARAMETERS

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa	Long Valley
T _{ambient} , °C (°F)	34.4 (94.0)	40.0 (104.0)	43.9 (111.0)	35.6 (96.0)
P _{ambient} , bar (psi)	0.87 (12.66)	0.95 (13.81)	1.01 (14.67)	0.90 (13.05)
T _{wet bulb} , °C (°F)	18.3 (65.0)	21.1 (70.0)	26.1 (79.0)	17.2 (63.0)
T _{cooling water} , °C (°F)	26.7 (80.0)	26.7 (80.0)	26.7 (80.0)	26.7 (80.0)

The possible impacts of high winds, dust, icing, snow and other adverse weather conditions have not been evaluated or considered in this study.

SECTION 3

ANALYSIS

3.1 The GEOTHEMF Program

Optimization calculations for hybrid coal/geothermal power plant cycles addressed in this study were performed using a modified version of the GEOTHEMF Program, referred to here as GEOTHEMF. [9] The modifications to GEOTHEMF, discussed below, were necessary to configure analytically, and to cost appropriately the hybrid power plant cycles. Whereas GEOTHEMF can analyze power plant cycles which use only geothermal energy sources, the GEOTHEMF version can analyze power plant cycles using either combined geothermal/fossil fuel energy sources or each source separately.

Many calculational approaches were considered for performing power plant cycle optimization analysis; however, the generalized optimization procedure contained in the GEOTHEMF program proved most suitable. Also, the flexibility of the GEOTHEMF program and its modular component approach in describing thermodynamic power cycle configurations allowed the required program modifications and optimization calculations to be done within the allotted time for this study. Program familiarization involved direct contact between Pacific-Sierra and Lawrence Berkeley Laboratory (LBL) personnel. [10]

Modifications to the GEOTHEMF program represent about a 15 percent increase in the FORTRAN programming structure. These modifications involved adding the following:

- A furnace routine for the boiler
- An air preheater routine for the furnace
- Power plant cost functions

- A geothermal well and replacement requirement model
- Revisions in the output routines.

3.1.1 Air Furnace Routine

Development of the furnace routine for making up the boiler in GEOTHMF is based on the standard textbook or handbook treatments of the combustion chemistry for coal. The furnace routine calculates the mass fraction of the combustion products in terms of their component mass flow rates, and requires the impact of the standard fuel component constituents (reactants), excess air mass fraction, fuel heating value, and estimated fractional split between the CO and CO₂ combustion products. Constituents and values used in the plant optimization calculations are as follows: [11] , [12]

<u>Fuel Component</u>	<u>Coal Composition Molecular Weight</u>	<u>Mass (lb/lb-fuel)</u>
Oxygen	16.000	0.1595
Nitrogen	14.008	0.0117
Hydrogen	1.008	0.0457
Carbon	12.011	0.6698
Sulphur	32.066	0.006
Chlorine	35.457	0.0213
Silicon dioxide	60.090	0.08600

These values represent assumed averages for Wasatch-Emery Coal. The heating value assumed for the calculations is 26 864 J/gm (11 557 Btu/lb). Also, the excess air is assumed to be 25 percent and the fraction of carbon which gives rise to carbon monoxide (CO) formation is assumed to be 0.003, as compared to 0.997 for carbon dioxide (CO₂) formation. In the presence of the 25 percent excess air in the furnace combustion is assumed to take place stoichiometrically. The following products are formed as the flue gas:

Flue Gas Composition

Product Component	Molecular Weight	Mass (lb/lb-fuel)
O ₂	32.00	0.0525
N ₂	28.016	7.6586
H ₂ O	18.016	0.4030
CO ₂	44.011	2.4469
CO	28.011	0.0047
SO ₂	64.066	0.0120
HCl	36.465	0.0219
SiO ₂	60.090	9.0860

Estimates of the initial (maximum) flue gas temperature are determined by equating the collective heat content of the flue gas products with the fuel (coal) heating value on a mass (or mass flow rate) basis. For subsequent heat transfer considerations in the boiler components (superheat, resuperheat, boiler, and economizer), the flue gas is assumed to be an ideal gas. For heat capacity considerations, SiO₂ is assumed to be the ash portion of the coal.

For the combustion chemistry, the following reactions were considered:

In the reaction equation for water formation (Equation (26)), the $\mu_H M_H - \mu_{Cl} M_{Cl}$ term accounts for hydrogen in the coal for the formation of HCl. It should be pointed out, however, that the above reactions are not based on an analysis of reaction kinetics for competitive reaction considerations. For Equations (21) through (26),

μ = reciprocal atomic weight ($\frac{\text{lb-moles}}{\text{lb}}$) of fuel component

M = mass of fuel component (lb)

m = mass of flue gas component (lb)

ϵ = fraction of carbon which gives rise to CO.

From the reactions above, flue gas products masses are as follows:

$$m_{HCl} = \mu_{Cl} M_{Cl} / \mu_{HCl} \quad (27)$$

$$m_{SO_2} = \mu_S M_S / \mu_{SO_2} \quad (28)$$

$$m_{SiO_2} = M_{SiO_2} \text{ (no reaction assumed for ash)} \quad (29)$$

$$m_{CO_2} = \mu_C (1-\epsilon) M_C / \mu_{CO_2} \quad (30)$$

$$m_{CO} = \mu_C M_C / \mu_{CO} \quad (31)$$

$$m_{H_2O} = 1/2 (\mu_H M_H - \mu_{Cl} M_{Cl}) / \mu_{H_2O} \quad (32)$$

The fuel (coal) contains oxygen and nitrogen so that the following reactions must also be considered for O_2 and N_2 formation.

Then if combustion is assumed to take place stoichiometrically, the total amount of oxygen, $M_{O_2}^*$, required from the air will be amounts required in Equations (22), (24), (25), and (26) less the amount supplied by the fuel itself as given in Equation (33) above, and given as follows:

$$[\mu_{O_2} M_{O_2}^*] = [\mu_S M_S] + [\mu_C (1-\epsilon) M_C] + 1/2 [\mu_C \epsilon M_C] + 1/4 [\mu_H M_H - \mu_{Cl} M_{Cl}] - 1/2 [\mu_O M_O] \quad (35)$$

$$M_{O_2}^* = \{ \mu_S M_S + \mu_C (1-\epsilon/2) M_C + 1/4 [\mu_H M_H - \mu_{Cl} M_{Cl}] - 1/2 [\mu_O M_O] \} / \mu_{O_2} \quad (36)$$

Then assuming mass percentages 79 percent N_2 and 21 percent O_2 for air,

$$M_{N_2}^* = \frac{0.79}{0.21} M_{O_2}^* , \quad (37)$$

and the total amount air required for stoichiometric combustion is

$$M_{air}^* = M_{O_2}^* + M_{N_2}^* = \frac{1}{0.21} M_{O_2}^* \quad (38)$$

Now assuming combustion takes place in 25 percent air excess, γ , the actual amount of air, M_{air} , needed is

$$M_{air} = M_{air}^* + \gamma M_{fuel} \quad (39)$$

The actual amounts of molecular oxygen and nitrogen needed are,

$$M_{O_2} = M_{O_2}^* + 0.21 \gamma M_{fuel} \quad (40)$$

$$M_{N_2} = 0.79 (M_{air} + \gamma M_{fuel}) , \quad (41)$$

and in the flue gas, the amounts of molecular oxygen and nitrogen are

$$m_{O_2} = 0.21 \gamma M_{fuel} \quad (42)$$

$$m_{N_2} = M_{N_2} + M_N , \quad (43)$$

where M_N , the amount nitrogen in the coal, is determined from Equation (43) above.

Equations (27) through (32), (42) and (43) give the flue gas components from which initial temperature estimates can be made. Indexing the components $j = 1$ to 8, the molar enthalpy of the flue gas products was expressed as a function of temperature,

$$h_j(T) = A_j(T-T_o)^2 + B_j(T-T_o) \quad (\text{Btu/lb-mol}), \quad (44)$$

where T_o is the reference temperature; A_j and B_j are fit constants determined from enthalpy and heat capacity data. (The molar enthalpy for SiO_2 does not follow $h(T)$ but is instead given by $3\mu\text{RTSiO}_2$). Then for a coal heating value K (Btu/lb), mass M_{fuel} (lb), and heat of vaporization for water, $h_{\text{H}_2\text{O}}^*$ (Btu/lb-mol), the equations become:

$$\sum_{j=1}^8 [\mu_j m_j h_j(t)] + \mu_{\text{H}_2\text{O}} m_{\text{H}_2\text{O}} h_{\text{H}_2\text{O}}^* = K M_{\text{fuel}} \quad (45)$$

or

$$\sum_{j=1}^8 \mu_j m_j [A_j(T-T_o) + B_j] \cdot (T-T_o) = K M_{\text{fuel}} - \mu_{\text{H}_2\text{O}} m_{\text{H}_2\text{O}} h_{\text{H}_2\text{O}}^* \quad (46)$$

where K = heating value of the fuel (coal). Then,

$$T = T_o + \frac{K M_{\text{fuel}} - \mu_{\text{H}_2\text{O}} m_{\text{H}_2\text{O}} h_{\text{H}_2\text{O}}^*}{\sum_{j=1}^8 \mu_j m_j [A_j(T-T_o) + B_j]} \quad (47)$$

where:

j = flue gas product index

μ = reciprocal atomic weight (lb-mol/lb)

m = flue gas product (lb)

T_o = reference temperature for coal and air.

The above transcendental relationship is solved iteratively for the flue gas temperature, T , by first choosing an approximate value for T , and then substituting into the right hand side to find a new value until a convergence criterion is met.

The above relationship assumes fuel combustion energy going into water

vapor formation is lost for heat transfer purposes (i.e., exits the stack as water vapor). Actually, some portion of that energy may be recovered in the low temperature region of the flue gas, if condensation takes place. However, any such recovery is neglected for these calculations. For heat transfer considerations in the boiler components (superheat, resuperheat, boiler, and economizer) ideal gas assumptions are made for the flue gas property, where the mean molecular weight estimated from the combustion products is 30.07.

3.1.2 Air Preheater Routine

As part of the furnace routine, the GEOTHM code was modified to simulate preheating of air entering the furnace. In reality both air and coal are preheated with flue gas heat prior to entering into the combustion process. For the power plant optimization calculations, preheating involved restricting the preheated air temperature for air entering the furnace as follows:

Air temperature entering the furnace, $T_{a,2}$ was specified as an optimizable cycle parameter with the constraints, $T_{a,2} \leq T_{fg,1}$ and $T_{fg,2} \leq T_{a,1}$. Although the above modification does not directly simulate the air preheater in terms of a conventional heat exchanger, the effect on the cycle of heating both the air

and the coal are approximated to a reasonable degree. Any more detailed code simulation for preheating would have required more detailed boiler component information regarding physical parameters and costs, which were not available for this study.

3.1.3 Development of Cost Functions

Considerable program modifications are made in the costing routines of GEOTHM to satisfy study needs for analyzing the hybrid fossil/geothermal power plant cycles. The cost functions in GEOTHMF used for power plant optimization calculations fall under three categories:

- Plant component capital costs
- Site-specific costs
- Time-dependent cost factors.

By and large, the various plant, site-specific, and time-dependent costing algorithms are specifically developed and added to the GEOTHM Program for the purpose of this study. However, where existing cost algorithms in the GEOTHM were applicable, they were used either directly, or normalized to reflect the IPP capital cost information.

The site-to-site cost comparisons were made by the general costing method outlined in ERDA 76-141 "Comparing New Technologies for the Electric Utilities" December 1976. Quoting from that document: [13]

"A major portion of the study effort was devoted to obtaining estimates of the capital costs and technical characteristics of the generating systems from the best available sources, and then to recasting the cost estimates into a common economic framework to permit meaningful comparisons. The major basis of comparison is the cost per kilowatt-hour levelized over the lifetime of the plant. There is considerable controversy over which methodology should be used to levelize the capital component of the cost:

This study used a procedure that levelized the future revenue requirements in real terms, i.e., it produced a price per kilowatt-hour in 1975 dollars which, if inflated at the general inflation rate, would produce a cash flow equivalent in present value to the lifetime operating expenses and capital carrying charges of the plant."

With this method it is noted in the ERDA report that:

"Thus, in the cost comparisons presented below, the overall costs per kilowatt-hour are consistent amount the various systems but appear lower than the corresponding costs in the many other published analyses."

Each plant design in this report will therefore be an optimized one minimizing the 1976 present value of costs. The average annual costs given in this report and in the Appendixes are also 1976 values. For easier comparison, base year costs are sometimes presented. They represent the first-year costs of a plant built in 1976 without interest during construction.

In conformance with the ERDA study it was assumed:

- O&M costs escalate at 5 percent annually
- Coal costs escalate at 8 percent annually.

As mentioned in Section 1, all financing is assumed to be from the sale of bonds with an interest rate (typical for the City) of 6 percent and with equal current dollar payments over the plant life. A four year construction period, a 30 year lifetime, and an 85 percent plant utility factor are assumed. To provide convenient indexing of all plant costs, the costs for the IPP design is used as a base.

3.1.4 Plant Component Capital Costs

Each of the major component costs in the hybrid plants is based on vendor data as a function of power level, heat transfer area, or other appropriate factors, and then indexed to IPP component costs. In developing the plant costs, primary emphasis is placed on establishing power plant cost in a relative rather than absolute sense due to the comparative aspect of this study. Therefore, the cost relationships and values omit a detailed breakdown normally present in precise power plant design specifications. Accordingly, many of the costs given below represent aggregate values of various systems and components.

Plant component capital costs include:

- Land and land rights

- Structures and improvements
- Station electric, miscellaneous equipment and tools
- Auxiliary boiler, steam, fuel, mechanical, and I&C systems
- Coal handling
- Industrial waste
- Steam generation
- Turbine generator
- Feedwater heat exchanger
- Condenser
- Cooling tower
- Pumps
- Construction, labor/management.

For the above cost considerations, cost values are given by either functional relationships adjusting for economies for scale and depending upon cycle thermodynamic parameters, or specific values using average or representative amounts.

Capital costs based on net power rating. - Plant capital costs components given below include cost relationships accounting for economies of scale based on power plant rating, PR.

<u>Capital Component</u>	<u>Cost, Million \$</u>
Land and land rights	$0.9 \left(\frac{PR}{750} \right)^{0.5}$
Structures and improvements	$SF \times 57 \left(\frac{PR}{750} \right)^{0.5}$
Station electric, miscellaneous power plant and accessory electric equipment, and tools	$15.3 \left(\frac{PR}{750} \right)^{0.9}$

Auxiliary boiler, steam, and fuel system,
mechanical equipment, instrumentation,
and controls

$$18.3 \left(\frac{PR}{750} \right)^{0.9}$$

The above relationships are based on IPP costs assuming a net electrical plant output rating of 750 MW. SF is a cost multiplying factor for seismic considerations.

Capital costs based on net heat transfer rate. - Plant capital cost components given below include cost relationships accounting for economies of scale based on scaling the net heat transfer rate to the working fluid $\dot{Q}$ (MW).

<u>Capital Component</u>	<u>Cost, Million \$</u>
Coal handling	$8.2 \left(\frac{\dot{Q}}{1984} \right)^{0.7}$
Industrial waste	$1.2 \left(\frac{\dot{Q}}{1984} \right)^{0.75}$
Steam generation	$111 \left(\frac{\dot{Q}}{1984} \right)^{0.83} + f(C,A,)$

The above relationships are based on IPP costs assuming a heat transfer rate to the working fluid of $\dot{Q} = 1984$ MW. The exponents assumed for coal handling and industrial waste are believed to be reasonable for economies of scale considerations.

The relationship for steam generation is based on a cost breakdown for the cost of materials, $f(C,A)$, and for the heat exchange surfaces including the economizer (E), boiler (B), superheat (SH), resuperheat (RSH), the precipitator, the scrubber, and all the rest of the steam generation system. Based on projected IPP costs of \$140M for steam generation for a single IPP unit (the IPP has four units), the basic boiler cost is \$58M of which half, or \$29M, is assumed to be due strictly to material costs. Accordingly, \$111M ($140 - 58 + 29$) are assumed to be made up of all boiler costs other than strictly heat transfer surface materials, including different cleaning equipment, blowers, air and coal heaters, instrumentation and controls, structures, erection and installation. The scaling relationship for the nonheat transfer surface portion is

based on approximate boiler manufacturer cost estimates for various boiler sizes.

Although steam generation system equipment is individually designed for a particular set of power plant specifications, it is necessary to allow some variation in estimated steam generation system cost for calculations that treat as optimizable parameters the pinch points for the economizer, boiler, superheat, and resuperheat heat exchanger components. Assuming a direct relationship between the area of these boiler components and the cost of the heat transfer surface materials, the $f(C,A)$ term in the steam generation relationship above, is

$$f(C,A) = 10^{-3} (C_{SH} A_{SH} + C_{RSH} A_{RSH} + C_B A_B + C_E A_E) \quad , \quad (48)$$

where:

$$C_{SH} = 26.4 \text{ (\$/ft}^2\text{)}$$

$$C_{RSH} = 17.1 \text{ (\$/ft}^2\text{)}$$

$$C_B = 59.7 \text{ (\$/ft}^2\text{)}$$

$$C_E = 20.3 \text{ (\$/ft}^2\text{)}$$

and A_{SH} , A_{RSH} , A_B , and A_E are the areas (ft^2) for the superheat heat, resuperheat, boiler, and economizer, respectively. These areas of the heat exchanger components in the boiler are determined by the GEOTHMF Program in the plant cycle optimization calculations based on heat transfer rates given overall heat transfer coefficients, $U(\text{Btu/hr} - \text{ft}^2 - ^\circ\text{F})$, and optimized pinch points ($\Delta T_{\min}$).

Estimates of the overall heat transfer coefficient values given below are based on a review of boiler design specifications for a coal-fired plant, (COLSTRIP) [14][15], to estimate log-mean temperature differences, θ_m , of the heat exchanger components (superheat, resuperheat, boiler, and economizer). Then, also assuming typical values for the overall heat transfer rates,

$$U \theta_m (\text{Btu/hr} - \text{ft}^2), \quad (49)$$

$$U_{SH} = 13.94 (\text{Btu/hr} - \text{ft}^2 - ^\circ\text{F}) \quad (50)$$

$$U_{RSH} = 8.5 \text{ (Btu/hr - ft}^2 \text{ - } ^\circ\text{F)} \quad (51)$$

$$U_E = 7.58 \text{ (Btu/hr - ft}^2 \text{ - } ^\circ\text{F)} \quad (52)$$

$$U_B = \begin{cases} 7.4 \text{ (liquid)} \\ 8.8 \text{ (boiling)} \end{cases} \text{ (Btu/hr - ft}^2 \text{ - } ^\circ\text{F)} \quad (53)$$

The boiler component cost coefficients, $C(\$/\text{ft}^2)$ are determined by normalizing the total costs of the heat transfer surface materials to \$29M, based on the heat transfer rates of the IPP boiler components. Relative values of the component cost coefficients determined from representative boiler component costs ($\$/\text{ft}^2$) are also assumed. The equation for the boiler heat transfer surface component areas is:

$$A = \frac{\dot{Q}}{U\theta_m} \quad (54)$$

The component heat transfer coefficients determine the relationship,

$$29 \times 10^6 = C_{SH} A_{SH} + C_{RSH} A_{RSH} + C_B A_B + C_E A_E \quad (55)$$

where each coefficient is determined by relative weighing as follows:

$$C_{SH} = 0.442$$

$$C_{RSH} = 0.286$$

$$C_B = 1$$

$$C_E = 0.34$$

Turbine generator costs. - Turbine generator costs used in the optimization calculations are based on a cost algorithm developed from General Electric Company [4] price data for large steam turbine generator units. The costing algorithms takes into account economies of scale for turbine output rating, cost variations due to exhaust pressure and turbine inlet temperature, and pressure for the high pressure (from superheat) and intermediate pressure (from resuperheat) turbines. No connection is made for makeup which implicitly assumes a value of 3 percent. Accordingly, the turbine cost is given as:

$$C_T = C_{T,0} + 10^{-3}(C_{TT} + C_{T,P}) \quad (\text{Million } \$) \quad (56)$$

where $C_{T,0}$ is the basic turbine cost given as,

$$C_{1,0} = \begin{cases} 28.2 \left(\frac{ETR}{650} \right)^{0.739}, & 0.5 \leq P_{ex} \leq 4.5 \\ 28.9 \left(\frac{ETR}{650} \right)^{0.739}, & 0.4 < P_{ex} \leq 15 \end{cases} \quad (57)$$

and,

P_{ex} = turbine exhaust pressure, inches of Hg

ETR = equivalent turbine rating, MW

= STR(1 - x)

STR = shaft turbine rating, MW,

where x is a correction factor determined as follows:

$$0.5 \leq P_{ex} \leq 1, \quad x = 0.025 \quad (58)$$

$$0.5 < P_{ex} \leq 3.5, \quad x = 0.025 + 0.01(1 - P_{ex}) \quad (59)$$

$$3.5 < P_{ex} \leq 4.5, \quad x = 0.02(3.5 - P_{ex}) \quad (60)$$

$$4.5 < P_{ex} \leq 5.0, \quad x = 0.03398(P_{ex} - 4.5) - 0.003116 \quad (61)$$

$$5.0 < P_{ex} \leq 15, \quad x = 0.01(8 - P_{ex}) \quad (62)$$

The cost correction (reduction or add-on) for turbine inlet temperature variations for the high pressure (HP) and intermediate pressure turbine is given as:

$$C_{T,T} = C_{HP} + C_{IP} \quad (63)$$

where C_{HP} and C_{IP} are determined as follows:

HP Turbine Inlet
Temperature, °F

ETR Range, MW

C_{HP} , Thousand \$

901-950

200 ≤ ETR ≤ 700

200 (200 - ETR) - 60

951-1000	$200 \leq \text{ETR} \leq 1100$	0
1001-1051	$200 \leq \text{ETR} \leq 1100$	$600 (\text{ETR} - 200) + 180$
IP Turbine Inlet Temperature, °F		
ETR Range, MW		
<u>C_{IP}, Thousand \$</u>		
901-950	$200 \leq \text{ETR} \leq 700$	$200 (200 - \text{ETR}) - 60$
951-1000	$200 \leq \text{ETR} \leq 1100$	0
1001-1025	$200 \leq \text{ETR} \leq 500$	300
	$500 < \text{ETR} \leq 800$	$200 (\text{ETR} - 500) + 300$
1026-1050	$200 \leq \text{ETR} \leq 500$	500
	$500 < \text{ETR} \leq 800$	$200 (\text{ETR} - 500) + 500$

The cost correction for HP turbine inlet pressure, $C_{T,P}$, depends on the inlet pressure, P_1 (psig) and ETR (MW) as follows:

<u>Pressure Range</u>		<u>ETR Range, MW</u>		<u>C_{T,P}, Thousand \$</u>
$P_1 < 1750$		$\text{ETR} \leq 300$		$1200 (\text{ETR} - 300) + 120$
		$\text{ETR} > 300$		$3330 (\text{ETR} - 100)^2$
$1750 \leq P_1 < 2150$		$\text{ETR} \leq 300$		0
		$300 < \text{ETR} \leq 400$		$1200 (\text{ETR} - 400) + 120$
		$\text{ETR} > 400$		$3330 (\text{ETR} - 200)^2$
$2150 \leq P_1 < 2450$		$\text{ETR} \leq 300$		$1200 (300 - \text{ETR})$
		$300 < \text{ETR} \leq 400$		0
		$400 < \text{ETR} \leq 500$		$1200 (\text{ETR} - 500) + 1200$
		$\text{ETR} > 500$		$3330 (\text{ETR} - 300)^2$
		$\text{ETR} \leq 400$		$1200 (400 - \text{ETR})$
$2450 \leq P_1 < 3050$		$400 < \text{ETR} \leq 500$		0
		$\text{ETR} \geq 500$		$3330 (\text{ETR} - 400)^2$

$$P_i \geq 3050$$

$$ETR \leq 400$$

$$2100 (400-ETR) + 120$$

$$400 < ETR \leq 500$$

$$1200 (500-ETR)$$

$$ETR \geq 500$$

$$0$$

Feedwater heat exchangers. - The cost of feedwater heat exchangers are assumed to be a function of the pressure and the heat transfer area. Based on estimated cost data for the IPP feedwater heaters, the cost per unit area was approximated by:

$$C_A = 10 \left(\frac{P_s}{300} \right)^{0.282} (\$/ft^2) , \quad (64)$$

where P_s (psig) is the tube pressure. For the IPP, the total feedwater heater system, including piping and pumps, is about seven times the cost of just the feedwater heater alone. Accordingly, the cost of feedwater heaters for the power plant optimization calculations were as follows:

$$C_{FW} = (70 \times 10^{-6}) \left(\frac{P_s}{300} \right)^{0.282} \cdot A \quad (\text{Million } \$) \quad (65)$$

Condenser. - Optimization calculations used the condenser costing algorithm of GEOTHM. The algorithm considers a turbine exhaust pressure of 1.4 psi and a cooling tower inlet water pressure of 53.66 psi. Once the optimum area is determined, condenser costs can be calculated from the unit cost of \$5.03 per square foot.

Cooling Tower. - Cooling tower costs, C_{CT} , are based on the algorithm given in GEOTHM normalized to IPP costs.

$$C_{CT} = (30.08 \times 10^{-6}) \times TU \times SF \quad (\text{Million } \$) , \quad (66)$$

where SF is a cost multiplying factor for seismic considerations and TU is the required number of tower units, given as,

$$TU = RF \times GPM, \quad (67)$$

where RF is a rating factor depending on the wet bulb, range, and approach temperatures.

Pumps. - Pump costs are those in GEOTHM. The cost algorithm is as follows:

$$C_P = (0.046 + 1.1786 \times 10^{-5} \times P_M) P_P^Y \quad (\text{Million \$}) \quad (68)$$

where

$$Y = 0.917 + 2.239 \times 10^{-6} \times P_M$$

P_P = power transferred to the working fluid, MW

$P_M = P_i - 305.58$, bars

P_i = inlet pressure, bars

where

$$P_i = \begin{cases} 304.58, & P_i \leq 304.58 \\ P_i, & 304.58 < P_i < 2001.52 \\ 2001.52, & P_i \geq 2001.52 \end{cases}$$

Construction labor/management. - Indirect costs, including construction facilities, equipment, and engineering and management services, generally fall in the range of 25 to 29 percent of the physical plant costs. Based on project IPP costs, a value of 28.67 percent is assumed.

3.1.5 Site-Specific Costs

Site-specific costs in the GEOTHMF program include:

- Drilling and surface piping costs for geothermal wells
- Coal
- Cooling water
- Transmission
- Seismic Risk.

Because of its dependence upon the resource depletion rate, the total number of wells needed during the lifetime of the plant will be discussed in the section on time dependent costs.

Well drilling and piping. - Well drilling costs are based on cost information gathered for each of the four sites. The well depth is assumed to be 5000 to 6000 feet. One reinjection well is allowed for every two resource wells drilled, at a cost identical to that of the resource well.

<u>Site</u>	<u>Cost per well, C_w, \$</u>
Roosevelt Hot Springs	700 000
Coso Hot Springs	700 000
East Mesa	400 000
Long Valley	700 000

The overall capital cost per well is based on a cost multiplying factor, F_p , which considers the additional cost of ground level piping. F_p is based on the number of wells, n , and is determined in the GEOTHM program.

<u>Number of wells, n</u>	<u>F_p, vapor dominated wells</u>
$n < 6$	1.15
$6 < n < 18$	1.23
$18 < n < 36$	1.32
$36 < n < 60$	1.42
$60 < n < 90$	1.47
$n > 90$	1.48

The total cost of wells is then

$$C_{TW} = n F_p C_w \times 10^{-6} \quad (\text{Million \$}) \quad (69)$$

The model for determining the total number of resource wells required is based on exponential source depletion with a half-life of ten years, and will be treated in a later section.

Coal. - Based on data given in the supporting information to this report, the following relationship for coal costs, C_m , was added to GEOTHM.

$$C_T = \frac{C \dot{M}_C}{2200 P} \text{ (mill/s/kWh)} \quad (70)$$

where the cost per tonne, C(\$/tonne), is

$$C = \begin{cases} m_c \ell_n \frac{X}{15,000} + C_o, & X < 700,000 \\ C_1, & X > 700,000 \end{cases} \quad (71)$$

where

X = yearly consumption rate, (tonnes/yr)

$\dot{M}_C$ = hourly consumption rate, (lb/hr)

P = power plant rating, (MW)

m_c = site specific constant given below and where for each site:

Site	$\frac{m_c}{C}$	C_o (\$/tonne)	C_1 (\$/ton)
Roosevelt Hot Springs	0.6505	22.50	20.00
Coso Hot Springs	2.758	41.30	30.70
East Mesa	3.175	44.10	31.90
Long Valley	2.602	43.00	33.00

Cooling Water. - The cost of cooling water is based on a relationship of the form given in a study by RAND. [16]

$$C_{CW} = 3.6768 \times 10^{-7} \left(\frac{C_s \dot{M}_w}{P} + \frac{C_T \dot{M}_w d_T}{P} \right) + 5.8055 \times 10^{-8} \frac{\dot{M}_w}{P} \text{ (mill/s/kWh)} \quad (72)$$

where

C_s = cost of water at the source, (\$/acre-ft)

C_T = conveyance cost (\$/acre-ft-mile)

$\dot{M}_w$ = power plant cooling requirement, (lb/hr)

d_T = conveyance distance, (miles)

H = power plant elevation distance above water source, (ft) ($H \geq 0$)

P = power plant rating, (MW).

For Coso and Long Valley, it is assumed cooling water is obtained from the Los Angeles Aqueduct; for East Mesa, from the East Highline Canal; and for Roosevelt, from wells. (See Section 2.3 of this report.) Accordingly, the following site-specific values are used for the cost relationship above.

	<u>Roosevelt Hot Springs</u>	<u>Coso Hot Springs</u>	<u>East Mesa</u>	<u>Long Valley</u>
C_s (\$/acre-ft)	50	100	50	100
C_T (\$/acre-ft-mile)	4.21	4.21	4.21	4.21
d_T (miles)	15	10	2.3	6
H (ft)	0	0	0	0

Transmission. - Transmission is assumed to be to Victorville. Based on the supporting information to this report, the transmission cost was added to GEOTHM as follows:

$$C(P) = m_t(P_o - P) + C_o \text{ (mills/kWh)} \quad , \quad (73)$$

where P and P_o are power plant ratings in MW, and C_o is transmission cost in mills/kWh. Then, for the following ranges,

$$1 \quad 100 \leq P < 250$$

$$2 \quad 250 \leq P < 500$$

$$3 \quad 500 \leq P \leq 1000.$$

Site-specific parameters for the above cost relationship are

	<u>m_t</u>	<u>P_o</u>	<u>C_o</u>
1	0.006667	100	5.4

2	0.0048	250	4.4
3	0.0004	500	3.2

Coso Hot Springs

	$\frac{m_t}{t}$	$\frac{P_o}{o}$	$\frac{C_o}{o}$
1	0.006667	100	1.8
2	0.001	250	1.7
3	0.0004	500	1.2

East Mesa

	$\frac{m_t}{t}$	$\frac{P_o}{o}$	$\frac{C_o}{o}$
1	0.001333	100	2.6
2	0.0032	250	2.4
3	0.0004	500	1.6

Long Valley

	$\frac{m_t}{t}$	$\frac{P_o}{o}$	$\frac{C_o}{o}$
1	0.004667	100	3.7
2	0.0032	250	4.4
3	0.0004	500	3.2

Seismic Risk. - Seismic factors (SF) account for any additional construction costs needed to enable plants to withstand significant damage due to maximum expected earthquakes. The SF factors for each site were chosen after a review of its seismicity and maximum credible ground acceleration. (See Section 2.5 of this report.) Power plant components were also considered.

<u>Site</u>	<u>SF</u>
Roosevelt Hot Springs	1.00

Coso Hot Springs	1.02
East Mesa	1.10
Long Valley	1.03

The SF factors multiply the base capital costs of the structure, coal handling equipment and cooling towers. It is assumed the other plant components would withstand maximum expected seismic events owing to their dynamic loading factors.

3.1.6 Time Dependent Costs

Time dependent cost factors in GEOTHMF include:

- Plant lifetime, N
- Construction period, M
- Finance interest rate, f
- Inflation rate, g
- Coal cost growth rate, h
- O and M growth rate
- Well replacement rate
- O and M rates for plant and wells.

Since the cost of power is expressed in 1976 dollars, not current dollars, annual average cost factors are developed and added to the program. They multiply capital costs to obtain the average annual cost of producing power. Accordingly, the annual average plant costs take into account assumed inflation, bond interest, and coal cost growth rates.

Construction and bond interest cost factors. The following values in parentheses below are used in the plant optimization calculations:

- g = rate of inflation (0.05)
- f = bond interest rate (0.06)
- h = coal cost growth rate (0.08)
- N = plant life (30 years)

- M = plant construction time period (4 years)
- A = total 1976 dollar cost of plant including labor (assuming no escalation).

The construction cost factor (CCF) is

$$CCF = \frac{1}{M} \left[\frac{(1+f)^M - (1+g)^{-M}}{\ln(1+f) + \ln(1+g)} \right] \quad (74)$$

The true cost of the plant is then A x (CCF). The bond interest factor (BICF) is,

$$BICF = \frac{f(1+f)^N}{(1+f)^N - 1} \sum_{i=1}^N \frac{1}{(1+g)^{i+M}} \quad (75)$$

Accordingly, the total value of all bonds repaid (in 1976 dollars) is A x (BICF). Bond redemption is assumed to begin at the end of the (M+1)th year and continue at an accelerating rate until the end of the (M+N)th year.

Average annual capital cost. - The net capital factor (NCF) is the (CCF) x (BICF) product. Thus, a plant with a 1976 dollar cost, A, is assumed to be constructed (straight line) over a period of M years, including bond indebtedness (straight line) over this period. At the end of the Mth year, the plant is operational with a total accumulated dollar debt, A x (CCF), including the bonds plus interest. The total cost (in 1976 dollars) of the plant is then A x (NCF). Amortized over the operating life of the plant, the average annual capital factor (AACF), is

$$(AACF) = \frac{1}{N} \times (NCF) \quad , \quad (76)$$

and the average annual capital cost, (AACC), (in 1976 dollars) of redeeming the bonds is,

$$(AACC) = A \times (AACF) \quad , \quad (77)$$

Average annual coal cost. - The average annual coal cost factor, (AACCF), is

$$(AACCF) = \frac{1}{N} \sum_{i=1}^N \left[1 + (h-g) \right]^i \quad , \quad (78)$$

and the annual average coal cost is $C_0 \times (\text{AACCF})$, where C_0 is the yearly coal cost basis at the beginning of the first year of plant operation for a reference coal cost (e.g., 20.00 \$/ton). The O/M cost growth rate is assumed to be equivalent to the assumed inflation rate (5 percent per year). Therefore, plant and well O/M costs are a flat percentage of the corresponding capital costs; the same growth rate correspondence is also assumed for the cost of cooling water.

Well requirement over the plant lifetime. - The number of wells required at a given power plant site depends on the individual flow rate per well, $\dot{m}$, and the total plant flow rate demand, $\dot{M}$. Well replacement over the operating life of the plant is based on a model which assumes exponential resource depletion with a well half-life of 10 years under maximum flow rate conditions. Although only integer wells are drilled, plant flow requirements are not assumed to be restricted to integer well flow amounts. Therefore, assuming initial power plant flow rate demand, M , the equivalent number of wells becomes,

$$\frac{M}{m} = n + \gamma, \quad 0 \leq \gamma < 1, \quad (79)$$

where

n = integer number of wells

γ = partial well requirement.

Assuming exponential well resource depletion under maximum flow conditions, the original plant flow rate requirement would degrade exponentially as follows:

$$\dot{M}(t) = \dot{M} e^{-\lambda t}, \quad (80)$$

if resource replenishment is taken into account, and $\lambda = 0.693/T_{1/2}$; $T_{1/2}$ being the well half-life under maximum flow conditions. Accordingly, in order to maintain the constant plant flow rate demand level, M , an increasing flow rate with time must be supplied by the remainder of the partial well originally at excess level of $(1-\gamma)$; this flow increases with time as

$$\begin{aligned} \dot{M}'(t) &= \dot{M} - \dot{M}(t) \\ &= \dot{m}(n + \gamma) - \dot{m}(n + \gamma)e^{-\lambda t} \\ &= \dot{m}(n + \gamma) \cdot (1 - e^{-\lambda t}) \end{aligned} \quad (81)$$

For the above flow rate of the excess (originally) partial well, the mass resource remaining as a function of time is,

$$\begin{aligned} M'(t) &= (1-\gamma) \frac{\dot{m}}{\lambda} - \int_0^t M'(t) dt \\ &= (1-\gamma) \frac{\dot{m}}{\lambda} - \dot{m}(N+\gamma) \cdot \left[t - \frac{1}{\lambda} (1 - e^{-\lambda t}) \right] \end{aligned} \quad (82)$$

Under maximum flow conditions for the partial well, the initial time, t_1 , at which the first new well must be brought into service is given when

$$\dot{M}'(t_1) = \lambda M'(t_1) \quad (83)$$

Substituting in the above relationship and solving, the initial replacement time obtained is

$$t_1 = \frac{(1-\gamma)}{\lambda(n+\gamma)} \quad (84)$$

After, t_1 , each additional time period, Δt , required to add new wells consecutively is determined in a similar manner as above. Maintaining the required plant flow rate demand, $\dot{M}$, the resource mass remaining in the new well as a function of a time period, Δt , measured from t_1 , is

$$\begin{aligned} M''(t) &= \frac{\dot{m}}{\lambda} - \int_0^{\Delta t} \dot{M}'(t) dt \\ &= \frac{\dot{m}}{\lambda} - \dot{m}(n+\gamma) \cdot \left[t - \frac{1}{\lambda} (1 - e^{-\lambda t}) \right] \end{aligned} \quad (85)$$

Again under maximum flow conditions for the first new well, a second new well must be brought into service under the period, Δt , when

$$\dot{M}'(\Delta t) = \lambda M'(\Delta t) \quad (86)$$

Substituting and solving at the above for the well replacement time period,

$$\Delta t = \frac{1}{\lambda(n+\gamma)} \quad \text{when } t_1 < N(\text{plant life}) \quad (87)$$

Based on the above model, the number of wells required over the plant lifetime, $N(\text{yrs})$, is

$$N_W = \begin{cases} (n+1) & , \quad t_1 \leq N \\ (n+1) + I\left(\frac{30-t_1}{\Delta t}\right) & , \quad t_1 > N \end{cases} \quad (88)$$

where, $I(\)$, designates rounding up to the highest integer. The average annual number of resource wells is, N_W/N . Including reinjection wells, the average annual number of wells becomes $\bar{N}_W = 1.5 (N_W/N)$. Multiplying $\bar{N}_W$ by the cost per well and the pipe factor gives the annual average cost of wells.

3.1.7 Output Routine

Considerable revisions and modifications are made in the output routine for displaying optimized power plant cost and cycle information. Cost results output include a listing of capital costs and timedependent costs for cost optimized power plants. (See Section 4). Total plant capital costs are given in \$/kW and the cost of power is given in mills/kWh. Cycle output modifications to the GEOTHM Program include dual output of the thermodynamic properties in both SI and English units; revision of the overall plant cycle energy balance and efficiency statements; and cooling tower parameters. (See Appendices A through D.)

The convention in GEOTHMF is illustrated based on the accounting schematic shown in Figure 3-1. For a given net power plant electrical output rating, $P(\text{MW})$, other quantities such as turbine shaft power are calculated as indicated by the relationships shown in Figure 3-1, based on input component efficiencies as shown. All cycle process pumps are assumed to be directly coupled to the mechanical output of the turbines. Actually, large modern power plants, such as the IPP plant, use turbine extraction steam to drive special turbines supplying the pump power. However, since relative power plant comparisons are of primary interest for this study, that level of detail was unnecessary for the optimization calculations. Calculated power plant efficiencies in GEOTHMF are as follows:

Figure 3-1. - Accounting schematic for GEOTHRM

$$\text{Net plant efficiency} = \frac{P}{\dot{Q}_b + \dot{Q}_g}$$

$$\text{Fraction geothermal contribution} = \frac{\dot{Q}_g}{\dot{Q}_b + \dot{Q}_g}$$

$$\text{Geothermal utilization efficiency} = \frac{\dot{Q}_g}{\dot{Q}_{g, \text{ in}}}$$

$$\text{Geothermal conversion function} = \left(\frac{P}{\dot{Q}_b + \dot{Q}_g} \right) \left(\frac{\dot{Q}_g}{\dot{Q}_{g, \text{ in}}} \right)$$

3.2 Optimization Calculations

3.2.1 Cycle Configuration

The analytical cycle configuration used for the GEOTHM calculations is shown in Figure 3-2. Cycle components are linked together based on the GEOTHM input procedure where a minimum input data set is required to achieve a valid initial thermodynamic balance; these primarily include temperatures, pressures, and a reference steam flow rate. The cycle shown in Figure 3-2 includes a modular mockup of a hybrid fossil/geothermal power plant cycle including the boiler unit (air preheater, furnace, superheater, resuperheater, boiler, and economizer), turbines, condenser, wet cooling tower, geothermal feedwater heater, and the contact heat exchanger for regenerative feedwater heating from high pressure (HP) turbine steam extraction and pumps. Using the IPP as a guide, initial temperatures and pressures were specified for the HP and IP turbine inlet conditions, and the LP turbine exhaust. Basic input assumptions for the components were as follows:

Efficiencies

Pumps, $N_p = 0.8$

Fans, $N_F = 0.5$

Generators, $N_G = 0.98$

Turbine (isentropic), $N_T = 0.5$

Figure 3-2. - Analytical hybrid cycle

U-Factors

Superheater, $U_{SH} = 13.94 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$

Resuperheater, $U_{RSH} = 8.5 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$

Economizer, $U_E = 7.58 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$

Boiler, $U_B = 7.4 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$ liquid
 $= 8.8 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$ boiling

Geothermal FWHTR, $U_G = 225 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$

Condenser, $U_C = 176 \text{ (Btu/hr-ft}^2\text{-}^\circ\text{F)}$

Pinch Points, ΔT

Superheater, optimizable

Resuperheater, optimizable

Economizer, optimizable, $\geq 100^\circ\text{F}$

Geothermal FWHTF, optimizable, $\geq 10^\circ\text{F}$

Condenser, optimizable, $\geq 5^\circ\text{F}$

3.2.2 Optimizable Parameters

In the GEOTHMF Program, any thermodynamic parameter (temperature, pressure, pinch point) may be specified as an optimizable parameter. Selection of optimizable parameters is accomplished by examining the cycle configuration and identifying those able to affect independently the cycle thermodynamics and plant costs. Based on the cycle configuration shown in Figure 3-2, the following were designated as optimizable parameters for the power plant optimization calculations:

- IP turbine inlet pressure
- Geothermal feedwater heater outlet temperature
- Condensate water temperature

- Superheater pinch point, ΔT
- Resuperheater pinch point, ΔT
- Geothermal feedwater heater pinch point, ΔT
- Condenser pinch point, ΔT
- Preheat air temperature
- Cooling tower reject temperature.

For the GEOTHM calculations, the optimizable parameters were allowed to vary between specified maximum and minimum input values which result in altering all the cycle parameters dependent upon any single variation. The HP and IP turbine inlet temperature and pressure could also be specified as optimizable parameters; however, fixed values of 1000°F and 2415 psi were assigned for the HP turbine, and 1000°F and a maximum of 1208 psi was specified for the IP turbine inlet. This has the effect of confining the cycle below the supercritical region to resemble the IPP, although detailed simulation of the IPP was not necessary for this study.

3.2.3 Calculational Procedure

Hybrid cycle power plant optimization calculations were performed with the GEOTHMF Program using the LBL 7600 machine. Typical run times required about 45 seconds to perform from about 500 to 1000 consecutive cycle iterations for nine independently varying optimizable parameters.

The calculational procedure of GEOTHMF for determining an optimum plant design is based on finding a unique set, X^* , of cycle parameters such that a defined objective function, $f[X_k]$, is a minimum, i.e., $f[X^*] = \min \{f[X_k]\}$. Figure 3-3 illustrates this procedure.

The required input consists of data for:

- Energy source characteristics for coal and the geothermal resource
- Net power plant requirement
- Thermodynamic cycle definition

Figure 3-3. - GEOTHEMF power plant optimization procedure

- Thermodynamic efficiency factors for the cycle components
- Initial cycle state parameters
- Definition of optimizable parameters
- Definition of the objective function
- Cost data
- Appropriate constraint and penalty function data for the cycle components and state parameters.

The cycle can then be characterized by an overall parameter set, $X_k = \{x_1, x_2, \dots, x_N\}$, where x_i is the cycle parameter, e.g., temperature, pressure, pinch point Δt , or heat exchanger U-factor. For the plant optimization calculations, a certain number, N' , of the x_i parameters were designated as optimizable parameters, x'_i , where normally, $N' \ll N$. The initial set of parameters, X_0 , are the starting values for the optimization procedure. They must be specified in such a way as to result in the calculation of a reasonable, although not optimum, thermodynamic cycle. The dashed line in Figure 3-3 indicates a passive mode cycle calculation where, by option, the optimization routine is bypassed. For that option, the user designs the plant; otherwise, the optimization routine designs the plant in which GEOTHMF is used as a function generator.

In addition to X_i , the program output consists of a set of performance factors, $F = \{f_1[X_k], f_2[X_k], \dots, f_M[X_k]\}$, where $f_j[X_k]$ is, for example, the cost of power (mills/kWh), plant capital cost (\$/kW), net cycle efficiency (%), or geothermal resource contribution to power output (%). For these calculations, the cost of power (mills/kWh) is defined as the objective function, $f[X_k]$, to be minimized.

In the procedure as shown in Figure 3-3, an initial objective function $f[X_0]$ is calculated based on the initial thermodynamic cycle parameters, X_0 . In addition, a set of partial derivatives,

$$f'[X_0] = \frac{\partial F[X_0]}{\partial x'_1}, \quad \frac{\partial F[X_0]}{\partial x'_2}, \quad \dots, \quad \frac{\partial F[X_0]}{\partial x'_{N'}}, \quad (89)$$

are calculated based on input step values ($+ \Delta x_j'$) for the optimizable parameters. The optimization routine MINUIT utilizes the $f'[x_0]$ values to commence the cyclic optimization procedure. MINUIT employs two separate subroutines, SIMPLEX and MIGRAD, to develop parameter sets x_k , each of which are based on a different approach in searching for the global minimum of $f[x_k]$. The thermodynamic cycle calculations supply x_k , $f[x_k]$ and $f'[x_k]$. The optimization calculational procedure continues, as indicated by the feedback loop in Figure 3-3, as long as the convergence criteria, ϵ , is not satisfied. Parameter set improvements, x_{k+1} are developed by MINUIT and subsequent objective functions are determined. When the convergence criteria is satisfied, GEOTHMF performs a final calculation of the power plant cycle thermodynamics utilizing the current optimizable parameter values, $(x_1', x_2', \dots, x_N')$ to yield a set of all cycle parameters, x^* , and the set of plant performance factors, F^* , one of which is the minimum value of the designated objective function, $f[x^*] = \min f[x_k]$, the cost of power (mills/kWh).

The optimization calculations for this study, performed in the manner described above, results in a partially constrained minimum insofar as penalty cost functions were imposed for unrealistic parameter variations. Imposing both parameter constraint and penalty functions are the means whereby the optimization procedure is guided within the hard and soft boundaries, respectively, in order to resemble a modern power plant design such as the IPP.

SECTION 4

RESULTS AND CONCLUSIONS

4.1 Evaluation of the Hybrid Concept

4.1.1 General Site Evaluation

The energy cost comparisons of a 750 MW hybrid plant at each of the four geothermal sites is presented in Figure 4-1. The principal conclusions drawn from the comparisons are:

- The Roosevelt Hot Springs site has the potential of producing electrical energy delivered to Burbank at 10 percent less cost than a well-sited reference all-coal-fired plant at the IPP site or at Roosevelt
- The Coso Hot Springs site shows slightly greater cost than the all coal-fired plant for delivered electrical energy to Burbank
- The East Mesa and Long Valley sites did not show economic advantage for hybrid plants.

Although comparisons were not explicitly made between hybrid and all coal-fired plants located at Coso Hot Springs, East Mesa, or Long Valley, the hybrid plant would be competitive with any all-coal-fired plant at the same site.

Figure 4-2 explains why Roosevelt Hot Springs and Coso Hot Springs are more competitive than either East Mesa or Long Valley. With fewer geothermal wells, hybrid plants at Roosevelt Hot Springs and Coso Hot Springs would reduce the coal requirement. For example, the amount of coal could be reduced by at least 46.3 t/hr (51.0 tons/hr) at Roosevelt Hot Springs. Further, East Mesa and Long Valley have larger cost penalties owing to their greater distance from the coal source.

Table 4-1 lists site-specific physical and cost parameters for the 750 MW

- 1 = Cost of power based on IPP estimating methods (Table 4-3)
 2 = Base year (1976) annual costs (Table 4-4)
 3 = Average annual costs based on ERDA costing method (Table 4-2)

Figure 4-1. - Energy cost comparisons for a 750 MW hybrid plant

Figure 4-2. - Energy input for a 750 MW hybrid plant

Table 4-1. - SITE-SPECIFIC PHYSICAL AND COST PARAMETERS FOR A 750 MW HYBRID PLANT

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
Geothermal temperature, T_s °C (°F)	249 (480)	246 (475)	182 (359)	160 (320)
Geothermal reject temperature, T_r °C (°F)	81 (178)	83 (181)	57 (135)	56 (136)
Geothermal mass flow rate per well, in t/hr (klb/hr)	454 (1000)	407 (896)	234 (515)	181 (398)
Number of geothermal wells	5	5	9	11
Well cost, K\$/well	700	700	400	700
Geothermal heat fraction, ϕ	20.71%	19.20%	14.67%	11.69%
Coal consumption, t/hr (klb/hr)	247 (545)	252 (555)	272 (599)	277 (610)
Coal cost, \$/t (\$/ton)	20.00 (18.00)	30.70 (27.90)	31.90 (29.00)	33.00 (30.00)
Cooling reject heat, MW (MBtu/hr)	1320 (387)	1319 (386)	1284 (376)	1264 (370)
Cooling water required, t/hr (klb/hr)	1899 (4187)	2024 (4463)	2136 (4710)	1840 (4056)
Cost of cooling water, mills/kWh	0.2322	0.3109	0.1378	0.2491
Transmission, mills /kWh	2.9	1.1	1.5	2.1
Seismic factor ¹	1.00	1.02	1.10	1.03
Plant net efficiency, η	35.61%	35.59%	36.10%	36.60%

¹ Multiplier for cost of: structure, coal handling equipment, and cooling towers.

hybrid plant. Roosevelt Hot Springs and Coso Hot Springs display the highest geothermal temperatures, mass flow rates, and geothermal utilization percentages. Therefore, coal consumption is less for the two sites than for either East Mesa or Long Valley. Also, the cost of delivered coal to East Mesa and Long Valley is much higher. Although Roosevelt Hot Springs shows the highest transmission costs, it also has the lowest coal costs. It is less expensive to transmit electricity than coal from Utah to California.

Physical and cost parameters for the 250 MW plant are presented at the end of section 4.1 (Tables 4-8 through 4-13).

4.1.2 Cost Results

Average annual and base year costs for the 750 MW plant are given in Tables 4-2, 4-3, and 4-4. Table 4-3 shows the annual costs based on the IPP cost estimation method. The cost of coal delivered to the geothermal site is the principal economic factor that impacts upon the cost of delivered electrical power from the hybrid plant. In comparison, well cost and well O and M are less than 5 percent of the coal costs for each of the four sites; and they are roughly equal to the cost of cooling water. These data indicate that feedwater heating is indeed the most significant application of the geothermal fluid, by its replacement of coal.

Additionally, using the geothermal fluid to dry coal or to supply power to an auxiliary boiler would further increase its ability to replace coal. Further savings would result if the geothermal fluid is used to supply cooling water.

It should be noted that well costs do not include royalties or profits, as they cannot be reliably estimated. If royalties or profits are large enough, they could affect site selection.

A breakdown of the capital costs for the 750 MW hybrid plant is shown in Table 4-5. The capital cost of geothermal wells, larger condenser, and turbine-generator is more than offset by the reductions in the capital cost of the boiler for an all-coal plant. At Roosevelt Hot Springs or Coso Hot Springs, the

TABLE 4-2. - AVERAGE ANNUAL COSTS FOR A 750 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley		All-Coal Roosevelt	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital	11.548	2.0664	11.652	2.0850	12.588	2.2525	12.299	2.2009	12.019	2.1507
Plant O and M	11.778	2.1076	11.806	2.1127	13.045	2.3344	12.502	2.2373	11.880	2.1258
Well Cost	0.325	0.0581	0.352	0.0630	0.347	0.0621	0.723	0.1294	----	----
Well O and M	1.035	0.1853	1.035	0.1853	1.138	0.2037	2.435	0.4357	----	----
Coal	64.781	11.5925	101.210	18.1114	113.616	20.3314	119.759	21.4306	76.917	13.7642
Cooling Water	1.298	0.2322	1.737	0.3109	0.770	0.1378	1.392	0.2491	1.166	0.2086
Total	90.765	16.2421	127.792	22.8683	141.504	25.3219	149.110	26.6830	101.982	18.2493
Transmission		2.94		1.24		1.78		2.63		3.12
Common Cost	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28
Cost of power (at Victorville)		20.46		25.39		28.38		30.59		22.65

* based on ERDA costing methods

TABLE 4-3. - ANNUAL COSTS BASED ON IPP ESTIMATE FOR A 750 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley		750-MW all-Coal at Roosevelt		IPP Figures for (1) - 750 MW Unit	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital ²	30.47	5.45	30.75	5.50	33.22	5.94	32.46	5.81	31.71	5.67	29.64 ⁴	5.3
Plant O and M	11.778	2.1076	11.806	2.1127	13.045	2.3344	12.502	2.2373	11.778	2.1076	14.85 ⁴	2.67
Well cost	0.325	0.0581	0.352	0.0630	0.347	0.0621	0.723	0.1294	0	0	0	0
Well O and M	1.035	0.1853	1.035	0.1853	1.138	0.2037	2.435	0.4357	0	0	0	0
Coal ³	36.9	6.6	57.0	10.2	59.2	10.6	61.5	11.0	43.41	7.8	43.41	7.8
Cooling water	1.298	0.2322	1.737	0.3109	0.770	0.1378	1.392	0.2491	1.30	.23	1.30 ¹	.23
Subtotal, plant	81.806	14.64	102.68	18.37	107.72	19.28	111.01	19.87	88.198	15.81	87.91	16.0
Transmission		2.8		1.10		1.55		2.21		2.8		2/4
Additional costs common to all sites ⁵	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28
Total cost of power at Victorville		18.72		20.75		22.11		23.36		19.89		19.28/ 21.88

- 1) Used Roosevelt Figure; IPP figures on different basis.
- 2) Not including interest during construction.
- 3) Coal price, 1976; no allowance for increased cost of fuel.
- 4) IPP cost ÷ 4.
- 5) Interest during construction and community development.

*Burbank Estimated Analysis from Pacific-Sierra Figures and IPP Costs Books

TABLE 4-4. - BASE YEAR ANNUAL COSTS FOR A 750 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley		All-Coal Roosevelt	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital	26.674	4.773	26.914	4.8160	29.076	5.2028	28.408	5.0837	27.752	4.966
Plant O and M	11.778	2.1076	11.806	2.1127	13.045	2.3344	12.502	2.2374	11.880	2.1259
Well Cost	0.751	0.1342	0.813	0.1455	0.802	0.1434	1.670	0.2989	-----	-----
Well O and M	1.035	0.1853	1.035	0.1853	1.138	0.2037	2.435	0.4357	-----	-----
Coal	36.826	6.5899	57.533	10.2955	64.586	11.5575	68.0777	12.1824	43.725	7.8245
Cooling Water	1.298	0.2322	1.737	0.3109	0.770	0.1378	1.392	0.2491	1.166	0.2086
Total	78.362	14.022	99.838	17.866	109.417	19.580	114.485	20.487	84.550	15.125
Transmission		2.74		0.996		1.55		2.252		2.844
Common Cost	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28	7.1	1.28
Cost of power (at Victorville)		18.042		20.14		22.41		24.02		19.25

TABLE 4-5. - PLANT CAPITAL COSTS FOR A 750 MW HYBRID PLANT

(MILLIONS OF DOLLARS)

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa	Long Valley	All-Coal Roosevelt
Land	0.9	0.9	0.9	0.9	0.9
Structure	57.0	58.140	62.7	58.710	57.0
Station electrical/ access equipment	15.3	15.3	15.3	15.3	14.7
Industrial waste equipment	1.054	1.07	1.103	1.120	1.1
Miscellaneous equipment	18.3	18.3	18.3	18.3	18.5
Coal handling equipment	7.268	7.515	8.236	7.920	7.7
Boiler	121.014	123.046	127.955	130.234	140.0
Turbine/generator	34.357	34.450	34.574	34.347	30.0
Condenser	1.784	1.906	2.049	1.602	1.5
Cooling tower	11.961	12.701	16.818	11.329	9.4
Pumps	1.239	1.282	1.256	1.201	1.2
Geothermal feedwater heater	9.086	7.225	15.067	8.635	15.0*
Geothermal wells	6.090	6.090	6.696	14.322	---
Plant	285.354	287.926	311.054	303.921	297.0
Indirect	<u>81.801</u>	<u>82.538</u>	<u>89.168</u>	<u>87.123</u>	<u>85.0</u>
Total	367.155	370.464	400.222	391.044	382.0
Power cost, \$/kW	489.540	493.952	533.629	521.392	509.0

*Extraction steam feedwater heating

cost of a hybrid plant would be slightly less than the cost of an equivalent size all coal-fired plant. The development cost of the geothermal resource in East Mesa or Long Valley would more than cancel the reduced cost of the boiler.

Cost risk estimates of the most important site-specific costs are presented in Table 4-6. Uncertainty of the values for the hybrid system arises principally because it is a newly developing technology. Also, uncertainty arises for the conventional fossil fuel system principally because of fuel availability and environmental restraints. However, the small uncertainties are associated with the highest cost factors; and the largest uncertainties accompany the lowest cost factors. A generally higher coal cost only would make the hybrid plant more attractive, even if the geothermal-related costs were also somewhat higher than expected.

4.1.3 Hybrid Plant Design

A well-designed and sited hybrid power plant can produce electricity at a lower cost than either a conventional coal-fired plant or an all-geothermal plant. Several performance characteristics of the hybrid plant account for its economic viability:

- Geothermal energy could economically contribute more than 20 percent of the total energy consumed in a hybrid plant. That is, the geothermal heat fraction, ϕ , can be greater than 0.2 for successful hybrid plants.
- The hybrid plant would utilize geothermal energy far more efficiently than present concepts for future all-geothermal plants. For high-quality geothermal resources, the utilization of geothermal energy is about 20 percent greater. For marginal resources, the utilization efficiency can be one-and-a-half times to twice as great. Thus, the hybrid cycle would be especially useful for marginal geothermal sites located near enough to coal deposits to be economically viable.
- The thermodynamic efficiency of the coal contribution to electrical power production in a hybrid plant is only slightly less than that of the best all coal-fired plant.

These conclusions were reached notwithstanding two major design restrictions as well as some lesser ones imposed on the hybrid plant for this analysis. First, the geothermal energy was used only to heat the feedwater before it entered the boiler. Second, the boiler feedwater was heated in a subcritical

TABLE 4-6. - MAXIMUM COST RISK ESTIMATES

Cost Factor	Average Annual Cost mills/kWh	Relative Cost Effect	Uncertainty	Maximum Cost, mills/kWh
Coal	11.5925	High	10%	12.75
Geothermal wells	0.0581	Low	100%	0.12
Geothermal well O and M	0.1853	Low	100%	0.37
Geothermal heat exchanger	0.0658	Low	100%	0.13
Emission control	0.3743*	Medium	25%	0.47
Seismic	0.5520**	Medium	50%	0.83
Cooling water	0.2322	Low	10%	0.26
Total risk cost	13.0602		14.25%	14.93
Total busbar cost	16.2421		11.46%	18.11
Total at Victorville	19.1821***		9.62%	21.05

* Assume 0.425 x Boiler Cost

** Based on structures, coal handling equipment and cooling tower costs

*** Assumes 2.94 mills/kWh transmission cost

cycle. Present judgment is that an actual hybrid design would encompass the following features:

- In addition to feedwater heating, the geothermal energy could have other applications, including:
 - coal drying and beneficiation
 - air preheating
 - flue gas reheating
 - auxiliary boiler heating
 - general heating.
- The quantity of geothermal fluid used for feedwater heating in a hybrid plant is nearly equal to the water evaporated by the plant cooling towers. Therefore, if the geothermal fluid is used for cooling tower makeup, most of the fluid will be evaporated and little or none will need to be re-injected.
- A temperature-entropy diagram for the cost-optimized 750 MW hybrid plant is given in Figure 4-3. The restriction to a subcritical cycle held the steam at just below the critical temperature and pressure. It appears that a supercritical cycle could be utilized, with maximum pressures of about 240 bars (3500 psia). Cycle temperatures and pressures for optimized 750 MW hybrid plant are given in Table 4-7. Additional thermodynamic detail is presented in Appendices A through D. The site-to-site and varying power rating difference of the optimized cycle do not affect the temperature-entropy profile significantly.
- More than one turbine extraction point probably would be used. This would allow flexibility to accommodate variations in the geothermal resource, as well as for high temperature steam for auxiliary station equipment. A possible arrangement of feedwater heaters to accomplish this operational flexibility is shown in Figure 4-4. As is evident, the hybrid plant even could accommodate some well-shutdowns.

In view of the above considerations, the hybrid plant could show even greater promise than that revealed in the present study. Moreover, all the components in the hybrid cycle are state of the art. Further, because of the use of coal, a guaranteed plant life is assured even if the lifetime or quality of the geothermal resource is overestimated.

Figure 4-3. - Temperature-entropy profile for a cost-optimized hybrid plant

TABLE 4-7. - CYCLE TEMPERATURE ($^{\circ}\text{F}$) AND PRESSURE (psi) FOR A 750 MW HYBRID PLANT

Position		Site			
		Roosevelt Hot Springs	Coso Hot Springs	East Mesa	Long Valley
Boiler inlet	T	573	575	537	541
	P	2868	2868	2868	2868
SH inlet	T	674	674	674	674
	P	2601	2601	2601	2601
HPT inlet	T	1004	1004	1004	1004
	P	2415	2415	2415	2415
HPT exit	T	810	811	732	740
	P	1207	1207	879	911
IPT inlet	T	1004	1004	1004	1004
	P	1150	1150	822	855
IPT exit	T	113	113	113	113
	P	1.41	1.41	1.41	1.41
GEO FWHTR inlet	T	118	118	117	117
	P	1232	1232	904	936
GEO FWHTR outlet	T	420	399	341	297
	P	1207	1207	879	911

Figure 4-4. - Series feedwater heaters

TABLE 4-8. - SITE-SPECIFIC PHYSICAL AND COST PARAMETERS FOR A 250 MW HYBRID PLANT

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
Geothermal temperature, T_g °C (°F)	249 (480)	246 (475)	182 (359)	160 (320)
Geothermal reject temperature, T_r °C (°F)	74 (165)	76 (169)	56 (133)	60 (140)
Geothermal mass flow rate per well, in t/hr (klb/hr)	454 (1000)	407 (896)	234 (515)	181 (398)
Number of geothermal wells	2	2	3	4
Well cost, K\$/well	700	700	400	700
Geothermal heat fraction, ϕ	21.65%	21.00%	14.74%	11.71%
Coal consumption, t/hr (klb/hr)	81 (179)	82 (181)	91 (200)	92 (203)
Coal cost, \$/t (\$/ton)	20.09 (18.22)	31.07 (28.19)	32.01 (29.04)	33.06 (29.99)
Cooling reject heat, MW (MBtu/hr)	441 (129)	442 (129)	428 (125)	421 (123)
Cooling water required, t/hr (klb/hr)	634 (1398)	678 (1494)	711 (1568)	613 (1351)
Cost of cooling water, mills/kWh	0.2326	0.3122	0.1376	0.2488
Transmission, mills/kWh	4.4	1.7	2.4	3.0
Seismic factor ¹	1.00	1.02	1.10	1.03
Plant net efficiency, η	35.57%	35.49%	36.14%	36.63%

¹ Multiplier for cost of: structure, coal handling equipment and cooling towers.

TABLE 4-9. - BASE YEAR ANNUAL COSTS FOR A 250 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital	10.720	5.5886	10.803	5.7993	11.5768	6.2155	11.270	6.050
Plant O and M	4.784	2.5488	4.765	2.5583	5.175	2.7784	4.929	2.6460
Well Cost	0.312	0.1679	0.374	0.2014	0.321	0.1725	0.626	0.3356
Well O and M	0.414	0.2223	0.414	0.2223	0.355	0.1906	0.828	0.4446
Coal	12.189	6.5435	19.004	10.2023	21.6315	11.6127	22.654	12.1615
Cooling Water	0.433	0.2326	0.582	0.3122	0.256	0.1376	0.463	0.2488
Total	28.816	15.304	35.942	19.296	39.315	21.107	40.770	21.887
Common Cost		1.28		1.28		1.28		1.28
Transmission		4.4		1.7		2.4		3.0
Cost of power (at Victorville)		20.984		22.276		24.787		26.167

TABLE 4-10. - AVERAGE ANNUAL COSTS FOR A 250 MW HYBRID PLANT

	Roosevelt Hot Springs		Coso Hot Springs		East Mesa		Long Valley	
	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh	M\$/yr	mills/kWh
Capital	4.641	2.4915	4.677	2.5107	5.012	2.6909	4.879	2.6192
Plant O and M	4.748	2.5488	4.765	2.5583	5.175	2.7784	4.929	2.6460
Well Cost	0.135	0.0727	0.162	0.0872	0.139	0.0747	0.271	0.1453
Well O and M	0.414	0.2223	0.414	0.2223	0.355	0.1906	0.828	0.4446
Coal	21.442	11.5110	33.431	17.9474	38.053	20.4285	39.851	21.3939
Cooling Water	0.433	0.2326	0.582	0.3122	0.256	0.1376	0.463	0.2488
Total	31.813	17.0789	44.031	23.6381	48.990	26.3007	51.221	27.4978
Common Cost		1.28		1.28		1.28		1.28
Transmission		4.4		1.7		2.4		3.0
Cost of power (at Victorville)		22.7589		26.6181		29.9807		31.7778

TABLE 4-11. - PLANT CAPITAL COSTS FOR A 250 MW HYBRID PLANT

(Millions of Dollars)

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa	Long Valley
Land	0.520	0.520	0.520	0.520
Structure	25.005	25.506	27.506	25.756
Station electric/ access equipment	5.692	5.692	5.692	5.692
Industrial waste equipment	0.459	0.463	0.483	0.491
Miscellaneous equipment	6.808	6.808	6.808	6.808
Coal handling equipment	3.343	3.435	3.859	3.668
Boiler	46.481	46.899	49.511	50.379
Turbine/generator	14.899	14.931	14.981	14.890
Condenser	0.596	0.642	0.665	0.554
Cooling tower	3.987	4.209	5.775	3.844
Pumps	0.451	0.459	0.455	0.434
Geothermal feedwater heater	4.009	3.567	5.521	2.658
Geothermal wells	2.436	2.436	2.088	4.872
Plant	114.686	115.570	123.863	120.563
Indirect	<u>32.876</u>	<u>33.130</u>	<u>35.507</u>	<u>34.561</u>
Total	147.563	148.700	159.370	155.124
Direct cost, \$/kW	590.251	594.798	637.479	620.498

TABLE 4-12. - PLANT CAPITAL COSTS COMPARISON BETWEEN A 250 MW ALL-COAL PLANT
AND A HYBRID PLANT AT ROOSEVELT HOT SPRINGS

	All-Coal	Roosevelt Hot Springs
Boiler/economizer/scrubber	\$ 55 M	\$ 46.5 M
Coal handling	4	3.3
Turbine-generator	13	14.9
Condenser and towers	4	4.6
Heat exchangers	5	4.0
Station electric	5.7	5.7
Structures	25	25
Geothermal wells	--	2.4 ¹
Other	8.2	8.2
Plant	120	114.6
Indirect	<u>34</u>	<u>32.9</u>
Total	\$ 154 M	\$ 147.5 M
Power cost	\$616/kW	\$590/kW

¹ 2 wells x 1000 klb/hr @ 480°F

TABLE 4-13. - CYCLE TEMPERATURE ($^{\circ}\text{F}$) AND PRESSURE (psi) FOR A 250 MW HYBRID PLANT

Position		Site			
		Roosevelt Hot Springs	Coso Hot Springs	East Mesa	Long Valley
Boiler inlet	T	575	573	534	541
	P	2868	2868	2868	2868
SH inlet	T	674	674	674	674
	P	2601	2601	2601	2601
HPT inlet	T	1004	1004	1004	1004
	P	2415	2415	2415	2415
HPT exit	T	810	811	724	738
	P	1206	1207	852	904
IPT inlet	T	1004	1004	1004	1004
	P	1149	1150	795	847
IPT exit	T	113	113	113	113
	P	1.41	1.41	1.41	1.41
Geo FWHTR inlet	T	118	118	117	117
	P	1231	1232	877	929
Geo FWHTR outlet	T	433	424	343	297
	P	1206	1207	852	904

4.2 Performance Parameters

This section summarizes much of the results of this study in terms of the Brown University analysis. In particular, work amplification factors are introduced. [1]

4.2.1 Parameters Used in the Economic Figure of Merit, F_e

In Section 1 of this report, the following economic figure of merit was derived:

$$F_e = \frac{\gamma(1 + \phi) \eta}{(\eta_f^* + \xi \phi \eta_g^*)} \quad (90)$$

where

- η_f^* is the efficiency of the reference coal-fired plant
- η_g^* is the efficiency of a state-of-the-art all-geothermal plant
- η is the efficiency of the hybrid plant
- ϕ is the geothermal heat fraction
- ξ is the geothermal heat equivalence factor
- γ is the site-specific cost parameter.

A value of F_e approaching or exceeding unity would indicate the geothermal site would support a hybrid plant. In the case of a 750 MW plant, Table 4-14 gives the value of F_e and its determining parameters for each site:

TABLE 4-14. - VALUES OF F_e

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
η_g^* ¹	20%	20%	14%	13%
η_f^*	38%	38%	38%	38%
η	35.61%	35.59%	36.10%	36.60%
ϕ	0.207	0.192	0.147	0.117
ξ	0.13	0.10	0.13	0.24
γ	0.95	0.86	0.80	0.75
F_e	1.06	0.95	0.87	0.80

¹ Assumes a utilization efficiency of 0.7

According to Table 4-14, Roosevelt Hot Springs can be developed as a hybrid site. Coso Hot Springs also shows some potential although F_e is below unity. The East Mesa and Long Valley sites have questionable potential as hybrid sites. However, if γ equalled one; i.e., if there were no site penalty or advantage, then F_e would become,

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
$F_e (\gamma=1.0)$	1.12	1.10	1.09	1.07

Thus, if it were not for site-specific penalties, all four geothermal resources could provide viable hybrid sites.

4.2.2 The Geothermal Figure of Merit, F_g

To what extent could a hybrid plant improve the utilization of the geothermal energy at each of the four sites? If no more than $W_f^* = \eta_f^* Q_f$ is contributed by the fossil heat to the net work output W of the hybrid system, then the amount of work attributed to the geothermal energy is

$$W_g = W - W_f^* \quad (91)$$

A state-of-the-art all-geothermal plant utilizing the same resource would produce maximum work W_g^* . Therefore, a geothermal figure of merit F_g can be defined as

$$F_g = W_g / W_g^* \quad (92)$$

In terms of η_f^* , η_g^* and ϕ ,

$$F_g = [\eta (1+\phi) - \eta_f^*] / (\phi \eta_g^*) \quad (93)$$

Using the values given in Table 4-14, the value of F_g for a 750 MW plant at each site is:

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
F_g	1.20	1.16	1.66	1.89

Figure 4-5 shows the geothermal figure of merit, F_g , as a function of the geothermal temperature, T_s .

Figure 4-5. - The geothermal figure of merit, F_g

In order for a separate geothermal plant to produce the same amount of work attributable to the geothermal part of the hybrid system, its utilization efficiency n_u must be higher than a limiting (threshold) value n_u^* . This threshold value can be obtained by $\eta_g^* = n_u \bar{\eta}_g^o$ and the thermodynamic figure F equal to unity. Hence,

$$n_u^* = [\eta(1+\phi) - \eta_f^*] / \phi \bar{\eta}_g^o \quad (94)$$

Calculated values of n_u^* for each of the sites are:

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
n_u^*	0.86	0.82	Greater than one	Greater than one

Present forecasts for future state of the art in geothermal energy utilization (n_u) is for values of 0.6 to 0.7. This report has assumed 0.7 in its calculations. It can be seen that the needed threshold value of n_u for Roosevelt Hot Springs and Coso Hot Springs is well above these state-of-the-art figures. East Mesa and Long Valley show values of n_u^* greater than one, which indicates that a hybrid plant at these sites would use geothermal energy more efficiently than an all-geothermal plant operating at the maximum theoretical efficiency. Thus, it is evident that the use of geothermal energy in a hybrid system has a considerable advantage over its use in a flash or a binary system.

4.2.3 The Work Amplification Factor, ψ

Another important performance parameter is the ratio of the work output of the hybrid plant using feedwater heating only to the maximum theoretical work output of an all-geothermal plant utilizing the identical source ($\bar{W}_g^o$). As a measure of this quantity the work amplification factor, ψ is introduced.

$$\psi = W / \bar{W}_g^o. \quad (95)$$

In terms of η , ϕ and $\bar{\eta}_g^o$,

$$\psi = \eta (1+\phi) / \phi \bar{\eta}_g^o \quad (96)$$

The value of ψ for each site is:

	Roosevelt Hot Springs	Coso Hot Springs	East Mesa KGRA	Long Valley KGRA
ψ	7.42	7.78	14.08	19.41

The dependence of the work amplification factor, ψ , on the geothermal temperature, T_s , is shown in Figure 4-6. Thus, if a geothermal resource at 200°C can develop a maximum of 75 MW, a hybrid plant utilizing the same geothermal resource should be designed for a capacity of about 750 MW.

Figure 4-6. - Work amplification factor

SECTION 5

RECOMMENDATIONS

5.1 Hybrid Power Plant Construction Recommended

The results of this present study and the Brown University study show that the hybrid cycle can combine the two abundant national resources, coal and geothermal energy, to advantage. The general recommendation is to design, construct, and operate one or more hybrid power plants at suitable geothermal sites as soon as practicable. An operational target date of 1984 would be a desirable goal. Supporting recommendations are given below.

5.1.1 Site Selection

Depending on the results of further field exploration and reservoir testing, it may be desirable to construct a hybrid plant at Roosevelt Hot Springs or Coso Hot Springs. Other geothermal resource areas also may merit serious evaluation as hybrid sites. Therefore, recommended site-selection efforts include:

- Determination of the testing needed to validate the suitability of the geothermal sites for hybrid plants
- Verification of the reservoir temperatures and production flow rates for significant periods of time
- Evaluation of reservoir size and lifetime in order to design for best plant sizing and plant economics.

The investment required for a hybrid plant necessitates, insofar as possible, a thorough and accurate analysis of the reservoir characteristics.

5.1.2 Preliminary Power Plant Design

Preliminary design of the hybrid geothermal/coal power plant should commence as soon as possible in order to:

- Validate the parametric analysis of this study
- Arrive at a preliminary optimum system design.

As a first design step, preliminary bid specifications should be developed for a hybrid plant to be constructed at Roosevelt Hot Springs or Coso Hot Springs. The bid specifications should be reviewed by architectural and engineering (A & E) firms, vendors, and other consultants in order to ensure an adequate final system design.

To support the preliminary design effort, the parametric study should be extended to include:

- Supercritical cycles, as these show promise of more efficient geothermal energy utilization
- Off-peak cycles, whereby boiling is performed by the geothermal fluid and only superheating is supplied by the coal (i.e., 85 percent geothermal energy and 15 percent coal energy)
- Auxiliary uses of geothermal energy, such as coal drying and power plant cooling.

5.1.3 Environmental Studies

Some of the preliminary information required for the Environmental Impact Assessment Report (EIAR) and the Environmental Impact Report (EIR) has been acquired during this study. Of special importance has been the attentive examination of several alternative sites for a hybrid plant, however, considerably more information needs to be obtained. An EIAR/EIR for the selected site must be completed in accordance with the "Guidelines to the Preparation of Environmental Reports for Geothermal Development Projects" (ERHQ-0001), prepared by ERDA/DGE.

5.1.4 Development of New Coal Mines

For full load operation of a plant over 100 MW, it is anticipated that new mines will have to be developed. This will require time as well as investment by coal companies. Very early in the planning stage for actual construction of a plant, firm commitments for coal supply should be made -- possibly including advance cash payments -- to assure that coal will be available when the plant

is ready.

5.1.5 Development of Water Sources

Very early in the planning stage for actual construction of a plant, firm commitments for water supply should be made. Water rights should be determined and any legal or environmental problems should be resolved. At sites where applicable, the use of geothermal fluid for cooling water will minimize the need for outside sources of water.

5.1.6 Comprehensive Planning and Management Structure

Major delays and perhaps plant cancellations have resulted in recent years because the management structure was inadequate. Present management requirements to construct a 750 MW hybrid plant are extremely complex and demand special attention. A management plan should be developed to administer the many complexities, including financing, governmental relations, subcontractor relations, and community relations. Comprehensive planning should commence as soon as possible to ensure proper timing and integration of all the activities needed to complete the hybrid plant. Of particular importance in the planning will be:

- o An accurate analysis of the cash flow and source of funds
- o Predesign and procurement of components, which often requires long lead times
- o Satisfying all applicable local, State, and Federal laws and regulations.

5.2 Geothermal Handbook

The methodology, results, and conclusions should be incorporated into ERDA's geothermal conversion handbook. Many geothermal resources which under present technology cannot be economically utilized could contribute energy under the hybrid concept. Therefore, the portion of the handbook dealing with hybrid plants should be regarded as an important section.

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APPENDICES

Appendices A through D present details of site-specific cost-optimized designs for the four sites at two ratings: 750 MW and 250 MW. Appendix A, data for the Roosevelt Hot Springs site, contains

- Summary costs
- Time dependent costs
- Optimized state points (in both SI and English units)
- A temperature-entropy diagram for the optimized cycle
- Mass flow rates

for both power ratings. Appendices B, C, and D contain the same data for Coso Hot Springs, East Mesa, and Long Valley respectively. For comparison, Appendix E contains a heat balance diagram and a temperature-entropy plot for an IPP unit rated at 750 MW.

Appendix F contains a copy of the Brown University report, "Hybrid Fossil-Geothermal Power Plants".

Appendix A

ROOSEVELT - 750 MW AND 250 MW

Table A1
Summary Costs: Optimized Roosevelt - 750 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.900	
STRUCTURE	57.000	
STATION ELECTRICAL AND ACCESSORY EQUIP.	15.300	
INDUSTRIAL WASTE EQUIP.	1.054	
MISC. EQUIP.	18.300	
COAL HANDLING EQUIP.	7.268	
BOILER NO. 1	121.014	
CONDENSER NO. 1	1.784	
H.P. TURBINE/GENERATOR NO. 1	34.357	
GEOTHERMAL FEEDWATER HEATER NO. 1	9.086	
PUMP NO. 1	.260	
PUMP NO. 2	.696	
PUMP NO. 3	.283	
(1) COOLING TOWER(S)	11.961	
(5) GEOTHERMAL WELL(S)	6.090	
TOTAL PHYSICAL PLANT		285.354
CONSTRUCTION LABOR/MANAGEMENT	81.801	
TOTAL INITIAL PLANT		367.155
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 489.540/KW	

Table A2

Time Dependent Costs: Optimized Roosevelt - 750 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	100.00 %		
COAL COST (\$/TONNE: 1976)	\$ 20.00		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 10.026 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	11.548	2.0664	
AVG. ANNUAL PLANT O/M COST	11.778	2.1076	
AVG. ANNUAL WELL COST	.325	.0581	
AVG. ANNUAL WELL O/M COST	1.035	.1853	
AVG. ANNUAL COAL COST	64.781	11.5925	
AVG. ANNUAL COOLING WATER COST	1.298	.2322	
TOTAL AVG. ANNUAL COST	90.764	16.2421	
OBJECTIVE FUNCTION:			
BUSBAR COST:	16.2421 MILS/KWH		
TRANSMISSION COST:	3.1000 MILS/KWH		
COST OF POWER:	19.3421 MILS/KWH		

Table A3a
Optimized State Points: Roosevelt - 750 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	307.604	.873	9.476	.070
AIR				
PREHEAT IN	307.604	.873	9.476	.070
PREHEAT OUT	597.885	.873	300.762	.737
FLUE GAS				
S.H. IN	2397.778	.873	2703.036	2.721
RE S.H. IN	1711.503	.873	1819.529	2.287
BOIL/ECON IN	1537.146	.873	1595.063	2.149
PREHEAT IN	629.377	.873	426.405	.999
STACK OUT	424.291	.873	162.379	.492
WORKING FLUID				
BFP IN	569.924	83.228	1221.247	2.855
BFP OUT	573.689	203.244	1242.201	2.862
	573.689	197.720	1242.199	2.864
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	705.648	83.228	3117.565	6.101
RE S.H. IN	705.648	83.228	3117.565	6.101
	704.431	81.263	3117.565	6.111
RE S.H. OUT	813.973	81.263	3390.415	6.472
IP TURB IN	813.160	79.305	3390.415	6.482
LP TURB OUT	318.345	.097	2271.481	7.143
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.964	86.675	95.311	.281
GEO FWH IN	320.964	84.951	95.309	.281
GEO FWH OUT	488.686	84.951	818.207	2.094
REGEN HTR IN	488.687	83.228	818.209	2.094
BLEED STEAM IN	705.648	83.228	3117.565	6.101
COOLING WATER				
PUMP IN	300.427	.873	9.517	.031
PUMP OUT	300.509	3.700	9.863	.032
COND. OUT	315.542	3.700	72.666	.236
COOL TOWER IN	315.542	.873	72.665	.236
COOL TOWER OUT	300.427	.873	9.517	.031
COOLING AIR				
TOWER IN	307.604	.873	31.094	1.357
TOWER OUT	309.992	.873	129.246	.078
MAKEUP WATER	299.827	.873	7.010	.023
GEO WATER				
FWH IN	522.049	39.400	975.162	2.415
FWH OUT	354.325	39.400	234.952	.710

Table A3b
Optimized State Points: Roosevelt - 750 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	93.999	12.662	49.078	.106
AIR				
PREHEAT IN	93.999	12.662	49.078	.106
PREHEAT OUT	616.506	12.662	174.341	.266
FLUE GAS				
S.H. IN	3856.312	12.662	1207.399	.740
RE S.H. IN	2621.017	12.662	827.462	.636
BOIL/ECON IN	2307.175	12.662	730.934	.603
PREHEAT IN	673.190	12.662	228.372	.328
STACK OUT	304.036	12.662	114.831	.207
WORKING FLUID				
BFP IN	566.176	1207.121	570.180	.772
BFP OUT	572.953	2947.810	579.191	.773
	572.952	2867.691	579.190	.774
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	810.478	1207.121	1385.661	1.547
RE S.H. IN	810.478	1207.121	1385.661	1.547
	808.288	1178.621	1385.661	1.549
RE S.H. OUT	1005.464	1178.621	1502.995	1.635
IP TURB IN	1004.000	1150.223	1502.995	1.638
LP TURB OUT	113.332	1.407	1021.816	1.796
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	118.047	1257.116	85.990	.156
GEO FWH IN	118.047	1232.111	85.989	.157
GEO FWH OUT	419.947	1232.111	396.859	.590
REGEN HTR IN	419.948	1207.121	396.860	.590
BLEED STEAM IN	810.478	1207.121	1385.661	1.547
COOLING WATER				
PUMP IN	81.080	12.662	49.096	.097
PUMP OUT	81.229	53.664	49.244	.097
COND. OUT	108.288	53.664	76.252	.146
COOL TOWER IN	108.288	12.662	76.251	.146
COOL TOWER OUT	81.080	12.662	49.096	.097
COOLING AIR				
TOWER IN	93.999	12.662	58.375	.414
TOWER OUT	98.297	12.662	100.583	.108
MAKEUP WATER	80.001	12.662	48.018	.095
GEO WATER				
FWH IN	480.000	571.450	464.355	.666
FWH OUT	178.098	571.450	146.040	.259

Fig. A1--Temperature-Entropy Chart: Optimized Roosevelt - 750 MW

Table A4
Optimized Mass Flow Rates: Roosevelt - 750 MW

	(KG/SEC)	(KLB/HR)
COAL	68.64392	544.80211
COMBUSTION AIR	664.85452	5276.71100
FLUE GAS	733.49845	5821.51311
WORKING FLUID HP	731.68176	5807.09476
WORKING FLUID LP	603.43000	4789.20664
WORKING BLEED STEAM	128.25177	1017.88813
COOLING WATER	21014.43017	166783.96710
COOLING AIR	13573.21356	107725.70964
MAKEUP WATER	527.52848	4186.80364
GEO WATER	589.31744	4677.20037

Table A5
Summary Costs: Optimized Roosevelt - 250 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)
LAND	.520
STRUCTURE	25.005
STATION ELECTRICAL AND ACCESSORY EQUIP.	5.692
INDUSTRIAL WASTE EQUIP.	.459
MISC. EQUIP.	6.808
COAL HANDLING EQUIP.	3.343
BOILER NO. 1	46.481
CONDENSER NO. 1	.596
H.P. TURBINE/GENERATOR NO. 1	14.899
GEOTHERMAL FEEDWATER HEATER NO. 1	4.009
PUMP NO. 1	.095
PUMP NO. 2	.252
PUMP NO. 3	.104
(1) COOLING TOWER(S)	3.987
(2) GEOTHERMAL WELL(S)	2.436
TOTAL PHYSICAL PLANT	114.686
CONSTRUCTION LABOR/MANAGEMENT	32.876
TOTAL INITIAL PLANT	147.563
OBJECTIVE FUNCTION:	
CAPITAL COST OF POWER:	\$ 590.251/KW

Table A6

Time Dependent Costs: Optimized Roosevelt - 250 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	100.00 %		
COAL COST (\$/TONNE: 1976)	\$ 20.09		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 12.057 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	4.641	2.4915	
AVG. ANNUAL PLANT O/M COST	4.748	2.5488	
AVG. ANNUAL WELL COST	.135	.0727	
AVG. ANNUAL WELL O/M COST	.414	.2223	
AVG. ANNUAL COAL COST	21.442	11.5110	
AVG. ANNUAL COOLING WATER COST	.433	.2326	
TOTAL AVG. ANNUAL COST	31.814	17.0790	
OBJECTIVE FUNCTION:			
BUSBAR COST:	17.0790 MILS/KWH		
TRANSMISSION COST:	4.4000 MILS/KWH		
COST OF POWER:	21.4790 MILS/KWH		

Table A7a
Optimized State Points: Roosevelt - 250 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	307.604	.873	9.476	.070
AIR				
PREHEAT IN	307.604	.873	9.476	.070
PREHEAT OUT	601.543	.873	304.432	.743
FLUE GAS				
S.H. IN	2400.000	.873	2706.363	2.723
RE S.H. IN	1712.624	.873	1821.286	2.288
BOIL/ECON IN	1535.794	.873	1593.597	2.148
PREHEAT IN	630.423	.873	427.826	1.002
STACK OUT	422.789	.873	160.473	.487
WORKING FLUID				
BFP IN	570.808	83.166	1226.147	2.864
BFP OUT	574.566	203.244	1247.168	2.871
	574.566	197.720	1247.166	2.872
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	705.542	83.166	3117.384	6.101
RE S.H. IN	705.542	83.166	3117.384	6.101
	704.324	81.201	3117.384	6.111
RE S.H. OUT	813.973	81.201	3390.477	6.472
IP TURB IN	813.160	79.243	3390.477	6.483
LP TURB OUT	318.345	.097	2271.590	7.144
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.964	86.613	95.309	.281
GEO FWH IN	320.963	84.889	95.307	.281
GEO FWH OUT	495.714	84.889	850.620	2.159
REGEN HTR IN	495.714	83.166	850.622	2.160
BLEED STEAM IN	705.542	83.166	3117.384	6.101
COOLING WATER				
PUMP IN	300.445	.873	9.595	.032
PUMP OUT	300.528	3.700	9.941	.032
COND. OUT	315.547	3.700	72.684	.236
COOL TOWER IN	315.547	.873	72.683	.237
COOL TOWER OUT	300.445	.873	9.595	.032
COOLING AIR				
TOWER IN	307.604	.873	31.094	1.357
TOWER OUT	309.997	.873	129.285	.078
MAKEUP WATER	299.827	.873	7.010	.023
GEO WATER				
FWH IN	522.049	39.400	975.162	2.415
FWH OUT	347.297	39.400	205.471	.626

Table A7b
Optimized State Points: Roosevelt - 250 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	93.999	12.662	49.078	.106
AIR				
PREHEAT IN	93.999	12.662	49.078	.106
PREHEAT OUT	623.089	12.662	175.919	.267
FLUE GAS				
S.H. IN	3860.312	12.662	1208.830	.740
RE S.H. IN	2623.035	12.662	828.217	.636
BOIL/ECON IN	2304.741	12.662	730.303	.603
PREHEAT IN	675.074	12.662	228.983	.329
STACK OUT	301.332	12.662	114.012	.206
WORKING FLUID				
BFP IN	567.766	1206.224	572.287	.774
BFP OUT	574.531	2947.810	581.327	.775
	574.531	2867.691	581.326	.776
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	810.287	1206.224	1385.583	1.547
RE S.H. IN	810.287	1206.224	1385.583	1.547
	808.095	1177.724	1385.583	1.549
RE S.H. OUT	1005.464	1177.724	1503.022	1.636
IP TURB IN	1004.000	1149.325	1503.022	1.638
LP TURB OUT	113.332	1.407	1021.863	1.796
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	118.047	1256.218	85.989	.156
GEO FWH IN	118.046	1231.214	85.988	.157
GEO FWH OUT	432.597	1231.214	410.798	.605
REGEN HTR IN	432.598	1206.224	410.799	.605
BLEED STEAM IN	810.287	1206.224	1385.583	1.547
COOLING WATER				
PUMP IN	81.113	12.662	49.129	.097
PUMP OUT	81.262	53.664	49.278	.097
COND. OUT	108.296	53.664	76.260	.146
COOL TOWER IN	108.296	12.662	76.259	.146
COOL TOWER OUT	81.113	12.662	49.129	.097
COOLING AIR				
TOWER IN	93.999	12.662	58.375	.414
TOWER OUT	98.306	12.662	100.600	.108
MAKEUP WATER	80.001	12.662	48.018	.095
GEO WATER				
FWH IN	480.000	571.450	464.355	.666
FWH OUT	165.447	571.450	133.362	.239

Fig. A2--Temperature-Entropy Chart: Optimized Roosevelt - 250 MW

Table A8
Optimized Mass Flow Rates: Roosevelt - 250 MW

	(KG/SEC)	(KLB/HR)
COAL	22.61513	179.48816
COMBUSTION AIR	219.04011	1738.44252
FLUE GAS	241.65524	1917.93068
WORKING FLUID HP	241.48506	1916.57999
WORKING FLUID LP	201.47911	1599.06714
WORKING BLEED STEAM	40.00595	317.51285
COOLING WATER	7023.50641	55743.04191
COOLING AIR	4530.42122	35956.32227
MAKEUP WATER	176.13815	1397.94512
GEO WATER	197.71564	1569.19786

Appendix B

COSO - 750 MW AND 250 MW

Table B1
Summary Costs: Optimized Coso - 750 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)
LAND	.900
STRUCTURE	58.140
STATION ELECTRICAL AND ACCESSORY EQUIP.	15.300
INDUSTRIAL WASTE EQUIP.	1.070
MISC. EQUIP.	18.300
COAL HANDLING EQUIP.	7.515
BOILER NO. 1	123.046
CONDENSER NO. 1	1.906
H.P. TURBINE/GENERATOR NO. 1	34.450
GEOHERMAL FEEDWATER HEATER NO. 1	7.225
PUMP NO. 1	.260
PUMP NO. 2	.713
PUMP NO. 3	.309
(1) COOLING TOWER(S)	12.701
(5) GEOHERMAL WELL(S)	6.090
TOTAL PHYSICAL PLANT	287.926
CONSTRUCTION LABOR/MANAGEMENT	82.538
TOTAL INITIAL PLANT	370.464
OBJECTIVE FUNCTION:	
CAPITAL COST OF POWER:	\$ 493.952/KW

Table B2

Time Dependent Costs: Optimized Coso - 750 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	102.00 %		
COAL COST (\$/TONNE: 1976)	\$ 30.70		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 10.694 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	11.652	2.0850	
AVG. ANNUAL PLANT O/M COST	11.806	2.1127	
AVG. ANNUAL WELL COST	.352	.0630	
AVG. ANNUAL WELL O/M COST	1.035	.1853	
AVG. ANNUAL COAL COST	101.210	18.1114	
AVG. ANNUAL COOLING WATER COST	1.737	.3109	
TOTAL AVG. ANNUAL COST	127.793	22.8682	
OBJECTIVE FUNCTION:			
BUSBAR COST:	22.8682 MILS/KWH		
TRANSMISSION COST:	1.1000 MILS/KWH		
COST OF POWER:	23.9682 MILS/KWH		

Table B3a
Optimized State Points: Coso - 750 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	313.160	.952	15.051	.063
AIR				
PREHEAT IN	313.160	.952	15.051	.063
PREHEAT OUT	603.389	.952	306.285	.721
FLUE GAS				
S.H. IN	2401.111	.952	2708.799	2.701
RE S.H. IN	1710.763	.952	1819.565	2.264
BOIL/ECON IN	1539.701	.952	1599.220	2.128
PREHEAT IN	630.354	.952	427.896	.978
STACK OUT	425.416	.952	163.917	.471
WORKING FLUID				
BFP IN	570.796	83.238	1226.083	2.864
BFP OUT	574.552	203.244	1247.090	2.871
	574.552	197.720	1247.088	2.872
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	705.665	83.238	3117.595	6.101
RE S.H. IN	705.665	83.238	3117.595	6.101
	704.448	81.273	3117.595	6.111
RE S.H. OUT	813.973	81.273	3390.405	6.472
IP TURB IN	813.160	79.315	3390.405	6.482
LP TURB OUT	318.345	.097	2271.463	7.143
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.966	86.685	95.319	.281
GEO FWH IN	320.966	84.961	95.317	.281
GEO FWH OUT	477.309	84.961	766.359	1.986
REGEN HTR IN	477.309	83.238	766.361	1.986
BLEED STEAM IN	705.665	83.238	3117.595	6.101
COOLING WATER				
PUMP IN	302.163	.952	16.776	.055
PUMP OUT	302.244	3.700	17.113	.056
COND. OUT	315.551	3.700	72.701	.236
COOL TOWER IN	315.551	.952	72.700	.237
COOL TOWER OUT	302.163	.952	16.776	.055
COOLING AIR				
TOWER IN	313.160	.952	37.327	1.344
TOWER OUT	309.983	.952	118.713	.053
MAKEUP WATER	299.827	.952	7.010	.023
GEO WATER				
FWH IN	519.271	37.600	961.754	2.390
FWH OUT	355.966	37.600	241.840	.730

Table B3b
Optimized State Points: Coso - 750 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	104.000	13.808	51.475	.105
AIR				
PREHEAT IN	104.000	13.808	51.475	.105
PREHEAT OUT	626.413	13.808	176.716	.262
FLUE GAS				
S.H. IN	3862.312	13.808	1209.877	.735
RE S.H. IN	2619.686	13.808	827.477	.630
BOIL/ECON IN	2311.773	13.808	732.721	.598
PREHEAT IN	674.950	13.808	229.013	.323
STACK OUT	306.062	13.808	115.493	.202
WORKING FLUID				
BFP IN	567.745	1207.267	572.260	.774
BFP OUT	574.506	2947.810	581.294	.775
	574.506	2867.691	581.293	.776
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	810.509	1207.267	1385.673	1.547
RE S.H. IN	810.509	1207.267	1385.673	1.547
	808.319	1178.767	1385.673	1.549
RE S.H. OUT	1005.464	1178.767	1502.991	1.635
IP TURB IN	1004.000	1150.368	1502.991	1.638
LP TURB OUT	113.332	1.407	1021.808	1.796
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	118.051	1257.261	85.993	.157
GEO FWH IN	118.050	1232.257	85.993	.157
GEO FWH OUT	399.468	1232.257	374.563	.564
REGEN HTR IN	399.469	1207.267	374.564	.564
BLEED STEAM IN	810.509	1207.267	1385.673	1.547
COOLING WATER				
PUMP IN	84.205	13.808	52.217	.103
PUMP OUT	84.350	53.664	52.362	.103
COND. OUT	108.304	53.664	76.267	.146
COOL TOWER IN	108.303	13.808	76.266	.146
COOL TOWER OUT	84.205	13.808	52.217	.103
COOLING AIR				
TOWER IN	104.000	13.808	61.055	.410
TOWER OUT	98.281	13.808	96.053	.102
MAKEUP WATER	80.001	13.808	48.018	.095
GEO WATER				
FWH IN	474.999	545.343	458.590	.660
FWH OUT	181.051	545.343	149.002	.264

Fig. B1--Temperature-Entropy Chart: Optimized Coso - 750 MW

Table B4
Optimized Mass Flow Rates: Coso - 750 MW

	(KG/SEC)	(KLB/HR)
COAL	69.86652	554.50539
COMBUSTION AIR	676.69602	5370.69267
FLUE GAS	746.56253	5925.19806
WORKING FLUID HP	749.54068	5946.83457
WORKING FLUID LP	602.98743	4785.69419
WORKING BLEED STEAM	146.55325	1163.14038
COOLING WATER	23724.52061	188292.97927
COOLING AIR	16373.31996	129949.14614
MAKEUP WATER	562.32949	4463.00672
GEO WATER	562.05251	4460.80844

Table B5
Summary Costs: Optimized Coso - 250 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.520	
STRUCTURE	25.506	
STATION ELECTRICAL AND ACCESSORY EQUIP.	5.692	
INDUSTRIAL WASTE EQUIP.	.463	
MISC. EQUIP.	6.808	
COAL HANDLING EQUIP.	3.435	
BOILER NO. 1	46.899	
CONDENSER NO. 1	.642	
H.P. TURBINE/GENERATOR NO. 1	14.931	
GEOHERMAL FEEDWATER HEATER NO. 1	3.567	
PUMP NO. 1	.095	
PUMP NO. 2	.253	
PUMP NO. 3	.114	
(1) COOLING TOWER(S)	4.209	
(2) GEOHERMAL WELL(S)	2.436	
TOTAL PHYSICAL PLANT		115.570
CONSTRUCTION LABOR/MANAGEMENT	33.130	
TOTAL INITIAL PLANT		148.700
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 594.798/KW	

Table B6

Time Dependent Costs: Optimized Coso - 250 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	102.00 %		
COAL COST (\$/TONNE: 1976)	\$ 31.07		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 12.561 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	4.677	2.5107	
AVG. ANNUAL PLANT O/M COST	4.765	2.5583	
AVG. ANNUAL WELL COST	.162	.0872	
AVG. ANNUAL WELL O/M COST	.414	.2223	
AVG. ANNUAL COAL COST	33.431	17.9474	
AVG. ANNUAL COOLING WATER COST	.582	.3122	
TOTAL AVG. ANNUAL COST	44.032	23.6381	
OBJECTIVE FUNCTION:			
BUSBAR COST:	23.6381 MILS/KWH		
TRANSMISSION COST:	1.7000 MILS/KWH		
COST OF POWER:	25.3381 MILS/KWH		

Table B7a
Optimized State Points: Coso - 250 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	313.160	.952	15.051	.063
AIR				
PREHEAT IN	313.160	.952	15.051	.063
PREHEAT OUT	605.236	.952	308.138	.725
FLUE GAS				
S.H. IN	2402.222	.952	2710.478	2.701
RE S.H. IN	1714.612	.952	1824.690	2.267
BOIL/ECON IN	1539.146	.952	1598.653	2.128
PREHEAT IN	629.146	.952	426.379	.976
STACK OUT	422.924	.952	160.721	.464
WORKING FLUID				
BFP IN	569.818	83.243	1220.653	2.854
BFP OUT	573.584	203.244	1241.603	2.861
	573.583	197.720	1241.601	2.863
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	705.675	83.243	3117.611	6.101
RE S.H. IN	705.675	83.243	3117.611	6.101
	704.458	81.278	3117.611	6.111
RE S.H. OUT	813.973	81.278	3390.399	6.471
IP TURB IN	813.160	79.320	3390.399	6.482
LP TURB OUT	318.345	.097	2271.453	7.143
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.966	86.690	95.319	.281
GEO FWH IN	320.966	84.966	95.317	.281
GEO FWH OUT	490.832	84.966	828.079	2.114
REGEN HTR IN	490.833	83.243	828.081	2.114
BLEED STEAM IN	705.675	83.243	3117.611	6.101
COOLING WATER				
PUMP IN	302.261	.952	17.188	.057
PUMP OUT	302.342	3.700	17.524	.057
COND. OUT	315.564	3.700	72.757	.236
COOL TOWER IN	315.564	.952	72.756	.237
COOL TOWER OUT	302.261	.952	17.188	.057
COOLING AIR				
TOWER IN	313.160	.952	37.327	1.344
TOWER OUT	310.000	.952	118.839	.053
MAKEUP WATER	299.827	.952	7.010	.023
GEO WATER				
FWH IN	519.271	37.600	961.754	2.390
FWH OUT	349.404	37.600	214.303	.652

Table B7b
Optimized State Points: Coso - 250 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	104.000	13.808	51.475	.105
AIR				
PREHEAT IN	104.000	13.808	51.475	.105
PREHEAT OUT	629.736	13.808	177.513	.263
FLUE GAS				
S.H. IN	3864.312	13.808	1210.599	.735
RE S.H. IN	2626.614	13.808	829.681	.631
BOIL/ECON IN	2310.775	13.808	732.477	.598
PREHEAT IN	672.775	13.808	228.360	.323
STACK OUT	301.574	13.808	114.118	.200
WORKING FLUID				
BFP IN	565.984	1207.347	569.925	.771
BFP OUT	572.763	2947.810	578.934	.773
	572.762	2867.691	578.933	.773
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	810.527	1207.347	1385.680	1.547
RE S.H. IN	810.527	1207.347	1385.680	1.547
	808.336	1178.847	1385.680	1.549
RE S.H. OUT	1005.464	1178.847	1502.988	1.635
IP TURB IN	1004.000	1150.449	1502.988	1.638
LP TURB OUT	113.332	1.407	1021.804	1.796
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	118.051	1257.342	85.994	.157
GEO FWH IN	118.050	1232.337	85.993	.157
GEO FWH OUT	423.810	1232.337	401.105	.594
REGEN HTR IN	423.811	1207.347	401.106	.595
BLEED STEAM IN	810.527	1207.347	1385.680	1.547
COOLING WATER				
PUMP IN	84.382	13.808	52.394	.103
PUMP OUT	84.527	53.664	52.539	.103
COND. OUT	108.328	53.664	76.291	.146
COOL TOWER IN	108.327	13.808	76.290	.146
COOL TOWER OUT	84.382	13.808	52.394	.103
COOLING AIR				
TOWER IN	104.000	13.808	61.055	.410
TOWER OUT	98.312	13.808	96.108	.102
MAKEUP WATER	80.001	13.808	48.018	.095
GEO WATER				
FWH IN	474.999	545.343	458.590	.660
FWH OUT	169.239	545.343	137.160	.245

Fig. B2--Temperature-Entropy Chart: Optimized Coso - 250 MW

Table B8
Optimized Mass Flow Rates: Coso - 250 MW

	(KG/SEC)	(KLB/HR)
COAL	22.80140	180.96650
COMBUSTION AIR	220.84422	1752.76106
FLUE GAS	243.64562	1933.72756
WORKING FLUID HP	243.66976	1933.91913
WORKING FLUID LP	201.88903	1602.32055
WORKING BLEED STEAM	41.78072	331.59857
COOLING WATER	7994.37909	63448.50883
COOLING AIR	5473.70258	43442.80683
MAKEUP WATER	188.22974	1493.91171
GEO WATER	197.92136	1570.83060

Appendix C

EAST MESA - 750 MW AND 250 MW

Table C1
Summary Costs: Optimized East Mesa - 750 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.900	
STRUCTURE	62.700	
STATION ELECTRICAL AND ACCESSORY EQUIP.	15.300	
INDUSTRIAL WASTE EQUIP.	1.103	
MISC. EQUIP.	18.300	
COAL HANDLING EQUIP.	8.336	
BOILER NO. 1	127.955	
CONDENSER NO. 1	2.049	
H.P. TURBINE/GENERATOR NO. 1	34.574	
GEOTHERMAL FEEDWATER HEATER NO. 1	15.067	
PUMP NO. 1	.188	
PUMP NO. 2	.713	
PUMP NO. 3	.355	
(1) COOLING TOWER(S)	16.818	
(9) GEOTHERMAL WELL(S)	6.696	
TOTAL PHYSICAL PLANT		311.054
CONSTRUCTION LABOR/MANAGEMENT	89.168	
TOTAL INITIAL PLANT		400.222
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 533.629/KW	

Table C2
Time Dependent Costs: Optimized East Mesa - 750 MW
(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	110.00 %		
COAL COST (\$/TONNE: 1976)	\$ 31.90		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 11.279 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	12.588	2.2525	
AVG. ANNUAL PLANT O/M COST	13.045	2.3344	
AVG. ANNUAL WELL COST	.347	.0621	
AVG. ANNUAL WELL O/M COST	1.138	.2037	
AVG. ANNUAL COAL COST	113.616	20.3314	
AVG. ANNUAL COOLING WATER COST	.770	.1378	
TOTAL AVG. ANNUAL COST	141.504	25.3219	
OBJECTIVE FUNCTION:			
BUSBAR COST:	25.3219 MILS/KWH		
TRANSMISSION COST:	1.5000 MILS/KWH		
COST OF POWER:	26.8219 MILS/KWH		

Table C3a
Optimized State Points: East Mesa - 750 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	317.049	1.013	18.953	.058
AIR				
PREHEAT IN	317.049	1.013	18.953	.058
PREHEAT OUT	479.595	1.013	182.062	.473
FLUE GAS				
S.H. IN	2324.444	1.013	2596.747	2.628
RE S.H. IN	1706.835	1.013	1805.261	2.232
BOIL/ECON IN	1501.083	1.013	1541.583	2.068
PREHEAT IN	609.494	1.013	398.984	.913
STACK OUT	494.129	1.013	251.139	.644
WORKING FLUID				
BFP IN	549.372	60.581	1111.519	2.665
BFP OUT	553.919	203.244	1135.152	2.673
	553.918	197.720	1135.150	2.674
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	661.837	60.581	3042.942	6.125
RE S.H. IN	661.837	60.581	3042.942	6.125
	660.340	58.616	3042.942	6.138
RE S.H. OUT	813.981	58.616	3412.740	6.643
IP TURB IN	813.160	56.658	3412.740	6.658
LP TURB OUT	318.345	.097	2317.670	7.288
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.282	64.028	92.460	.279
GEO FWH IN	320.281	62.304	92.458	.279
GEO FWH OUT	444.969	62.304	622.319	1.679
REGEN HTR IN	444.970	60.581	622.321	1.679
BLEED STEAM IN	661.837	60.581	3042.942	6.125
COOLING WATER				
PUMP IN	304.445	1.013	26.314	.087
PUMP OUT	304.525	3.700	26.648	.087
COND. OUT	315.564	3.700	72.758	.236
COOL TOWER IN	315.564	1.013	72.757	.237
COOL TOWER OUT	304.445	1.013	26.314	.087
COOLING AIR				
TOWER IN	317.049	1.013	53.697	1.248
TOWER OUT	310.000	1.013	111.396	.035
MAKEUP WATER	299.827	1.013	7.010	.023
GEO WATER				
FWH IN	454.827	10.800	665.767	1.788
FWH OUT	330.138	10.800	133.647	.422

Table C3b
Optimized State Points: East Mesa - 750 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	111.000	14.692	53.154	.103
AIR				
PREHEAT IN	111.000	14.692	53.154	.103
PREHEAT OUT	403.583	14.692	123.296	.203
FLUE GAS				
S.H. IN	3724.312	14.692	1161.691	.717
RE S.H. IN	2612.615	14.692	821.326	.623
BOIL/ECON IN	2242.262	14.692	707.936	.583
PREHEAT IN	637.402	14.692	216.579	.308
STACK OUT	429.744	14.692	153.001	.243
WORKING FLUID				
BFP IN	529.181	878.657	522.993	.726
BFP OUT	537.365	2947.810	533.156	.728
	537.365	2867.691	533.156	.728
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	731.618	878.657	1353.570	1.553
RE S.H. IN	731.618	878.657	1353.570	1.553
	728.924	850.157	1353.570	1.556
RE S.H. OUT	1005.478	850.157	1512.596	1.676
IP TURB IN	1004.000	821.758	1512.596	1.680
LP TURB OUT	113.332	1.407	1041.679	1.831
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	116.819	928.651	84.764	.156
GEO FWH IN	116.818	903.647	84.763	.156
GEO FWH OUT	341.257	903.647	312.621	.491
REGEN HTR IN	341.257	878.657	312.622	.491
BLEED STEAM IN	731.618	878.657	1353.570	1.553
COOLING WATER				
PUMP IN	88.313	14.692	56.319	.110
PUMP OUT	88.457	53.664	56.462	.110
COND. OUT	108.328	53.664	76.291	.146
COOL TOWER IN	108.328	14.692	76.291	.146
COOL TOWER OUT	88.313	14.692	56.319	.110
COOLING AIR				
TOWER IN	111.000	14.692	68.094	.388
TOWER OUT	98.312	14.692	92.907	.098
MAKEUP WATER	80.001	14.692	48.018	.095
GEO WATER				
FWH IN	359.000	156.641	331.305	.517
FWH OUT	134.561	156.641	102.476	.190

Fig. C1--Temperature-Entropy Chart: Optimized East Mesa - 750 MW

Table C4

Optimized Mass Flow Rates: East Mesa - 750 MW

	(KG/SEC)	(KLB/HR)
COAL	75.48013	599.05865
COMBUSTION AIR	731.06701	5802.21571
FLUE GAS	806.54715	6401.27436
WORKING FLUID HP	720.75308	5720.35774
WORKING FLUID LP	575.09139	4564.29334
WORKING BLEED STEAM	145.66169	1156.06441
COOLING WATER	27853.85839	221066.04663
COOLING AIR	22536.01434	178860.23289
MAKEUP WATER	593.45631	4710.04913
GEO WATER	572.64870	4544.90658

Table C5
Summary Costs: Optimized East Mesa - 250 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.520	
STRUCTURE	27.506	
STATION ELECTRICAL AND ACCESSORY EQUIP.	5.692	
INDUSTRIAL WASTE EQUIP.	.483	
MISC. EQUIP.	6.808	
COAL HANDLING EQUIP.	3.859	
BOILER NO. 1	49.511	
CONDENSER NO. 1	.665	
H.P. TURBINE/GENERATOR NO. 1	14.981	
GEOHERMAL FEEDWATER HEATER NO. 1	5.521	
PUMP NO. 1	.067	
PUMP NO. 2	.259	
PUMP NO. 3	.129	
(1) COOLING TOWER(S)	5.775	
(3) GEOHERMAL WELL(S)	2.088	
TOTAL PHYSICAL PLANT		123.863
CONSTRUCTION LABOR/MANAGEMENT	35.507	
TOTAL INITIAL PLANT		159.370
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 637.479/KW	

Table C6

Time Dependent Costs: Optimized East Mesa - 250 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	110.00 %		
COAL COST (\$/TONNE: 1976)	\$ 32.01		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 11.197 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	5.012	2.6909	
AVG. ANNUAL PLANT O/M COST	5.175	2.7784	
AVG. ANNUAL WELL COST	.139	.0747	
AVG. ANNUAL WELL O/M COST	.355	.1906	
AVG. ANNUAL COAL COST	38.053	20.4285	
AVG. ANNUAL COOLING WATER COST	.256	.1376	
TOTAL AVG. ANNUAL COST	48.991	26.3006	
OBJECTIVE FUNCTION:			
BUSBAR COST:	26.3006 MILS/KWH		
TRANSMISSION COST:	2.4000 MILS/KWH		
COST OF POWER:	28.7006 MILS/KWH		

Table C7a
Optimized State Points: East Mesa - 250 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	317.049	1.013	18.953	.058
AIR				
PREHEAT IN	317.049	1.013	18.953	.058
PREHEAT OUT	469.855	1.013	172.288	.453
FLUE GAS				
S.H. IN	2318.889	1.013	2587.888	2.623
RE S.H. IN	1706.933	1.013	1804.174	2.231
BOIL/ECON IN	1497.164	1.013	1535.529	2.063
PREHEAT IN	607.957	1.013	396.747	.909
STACK OUT	499.432	1.013	257.762	.657
WORKING FLUID				
BFP IN	547.408	58.757	1102.892	2.649
BFP OUT	552.317	203.244	1126.788	2.658
	552.316	197.720	1126.786	2.659
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	657.786	58.757	3036.026	6.127
RE S.H. IN	657.786	58.757	3036.026	6.127
	656.259	56.792	3036.026	6.141
RE S.H. OUT	813.982	56.792	3414.516	6.659
IP TURB IN	813.160	54.834	3414.516	6.675
LP TURB OUT	318.345	.097	2322.091	7.302
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.227	62.204	92.230	.279
GEO FWH IN	320.226	60.480	92.228	.279
GEO FWH OUT	445.824	60.480	626.072	1.688
REGEN HTR IN	445.824	58.757	626.074	1.688
BLEED STEAM IN	657.786	58.757	3036.026	6.127
COOLING WATER				
PUMP IN	304.225	1.013	25.395	.084
PUMP OUT	304.305	3.700	25.729	.084
COND. OUT	315.446	3.700	72.261	.234
COOL TOWER IN	315.445	1.013	72.260	.235
COOL TOWER OUT	304.225	1.013	25.395	.084
COOLING AIR				
TOWER IN	317.049	1.013	53.697	1.248
TOWER OUT	310.000	1.013	111.395	.035
MAKEUP WATER	299.827	1.013	7.010	.023
GEO WATER				
FWH IN	454.827	10.800	665.767	1.788
FWH OUT	329.228	10.800	129.844	.411

Table C7b
Optimized State Points: East Mesa - 250 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	111.000	14.692	53.154	.103
AIR				
PREHEAT IN	111.000	14.692	53.154	.103
PREHEAT OUT	386.051	14.692	119.093	.198
FLUE GAS				
S.H. IN	3714.312	14.692	1157.882	.716
RE S.H. IN	2612.791	14.692	820.858	.622
BOIL/ECON IN	2235.207	14.692	705.332	.582
PREHEAT IN	634.635	14.692	215.618	.307
STACK OUT	439.290	14.692	155.849	.246
WORKING FLUID				
BFP IN	525.646	852.196	519.283	.722
BFP OUT	534.482	2947.810	529.560	.724
	534.482	2867.691	529.559	.725
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	724.328	852.196	1350.596	1.553
RE S.H. IN	724.328	852.196	1350.596	1.553
	721.579	823.696	1350.596	1.557
RE S.H. OUT	1005.479	823.696	1513.359	1.680
IP TURB IN	1004.000	795.298	1513.359	1.684
LP TURB OUT	113.332	1.407	1043.580	1.834
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	116.720	902.191	84.665	.156
GEO FWH IN	116.719	877.186	84.664	.156
GEO FWH OUT	342.795	877.186	314.235	.493
REGEN HTR IN	342.796	852.196	314.236	.493
BLEED STEAM IN	724.328	852.196	1350.596	1.553
COOLING WATER				
PUMP IN	87.917	14.692	55.924	.110
PUMP OUT	88.061	53.664	56.067	.110
COND. OUT	108.114	53.664	76.078	.145
COOL TOWER IN	108.114	14.692	76.077	.146
COOL TOWER OUT	87.917	14.692	55.924	.110
COOLING AIR				
TOWER IN	111.000	14.692	68.094	.388
TOWER OUT	98.312	14.692	92.907	.098
MAKEUP WATER	80.001	14.692	48.018	.095
GEO WATER				
FWH IN	359.000	156.641	331.305	.517
FWH OUT	132.923	156.641	100.840	.188

Fig. C2--Temperature-Entropy Chart: Optimized East Mesa - 250 MW

Table C8

Optimized Mass Flow Rates: East Mesa - 250 MW

	(KG/SEC)	(KLH/HR)
COAL	25.19165	199.93709
COMBUSTION AIR	243.99517	1936.50179
FLUE GAS	269.18682	2136.43888
WORKING FLUID HP	238.19075	1890.43422
WORKING FLUID LP	191.06381	1516.40470
WORKING BLEED STEAM	47.12693	374.02951
COOLING WATER	9188.09772	72922.62392
COOLING AIR	7501.67888	59538.12470
MAKEUP WATER	197.54618	1567.85288
GEO WATER	190.32224	1510.51911

Appendix D

LONG VALLEY - 750 MW AND 250 MW

Table D1
Summary Costs: Optimized Long Valley - 750 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.900	
STRUCTURE	58.710	
STATION ELECTRICAL AND ACCESSORY EQUIP.	15.300	
INDUSTRIAL WASTE EQUIP.	1.120	
MISC. EQUIP.	18.300	
COAL HANDLING EQUIP.	7.920	
BOILER NO. 1	130.234	
CONDENSER NO. 1	1.602	
H.P. TURBINE/GENERATOR NO. 1	34.347	
GEOTHERMAL FEEDWATER HEATER NO. 1	8.635	
PUMP NO. 1	.192	
PUMP NO. 2	.735	
PUMP NO. 3	.274	
(1) COOLING TOWER(S)	11.329	
(11) GEOTHERMAL WELL(S)	14.322	
TOTAL PHYSICAL PLANT		303.921
CONSTRUCTION LABOR/MANAGEMENT	87.123	
TOTAL INITIAL PLANT		391.044
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 521.392/KW	

Table D2

Time Dependent Costs: Optimized Long Valley - 750 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
HOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	103.00 %		
COAL COST (\$/TONNE: 1976)	\$ 33.00		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 24.928 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
HOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	12.299	2.2009	
AVG. ANNUAL PLANT O/M COST	12.502	2.2373	
AVG. ANNUAL WELL COST	.723	.1294	
AVG. ANNUAL WELL O/M COST	2.435	.4357	
AVG. ANNUAL COAL COST	119.759	21.4306	
AVG. ANNUAL COOLING WATER COST	1.392	.2491	
TOTAL AVG. ANNUAL COST	149.110	26.6830	
OBJECTIVE FUNCTION:			
BUSBAR COST:	26.6830 MILS/KWH		
TRANSMISSION COST:	2.1000 MILS/KWH		
COST OF POWER:	28.7830 MILS/KWH		

Table D3a
Optimized State Points: Long Valley - 750 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	308.716	.900	10.591	.065
AIR				
PREHEAT IN	308.716	.900	10.591	.065
PREHEAT OUT	488.885	.900	191.384	.526
FLUE GAS				
S.H. IN	2330.000	.900	2604.079	2.664
RE S.H. IN	1702.594	.900	1799.973	2.262
BOIL/ECON IN	1509.150	.900	1552.048	2.108
PREHEAT IN	611.697	.900	401.839	.950
STACK OUT	483.834	.900	237.966	.650
WORKING FLUID				
BFP IN	551.666	62.840	1123.414	2.686
BFP OUT	556.139	203.244	1146.837	2.694
	556.138	197.720	1146.835	2.695
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	666.725	62.840	3051.283	6.122
RE S.H. IN	666.725	62.840	3051.283	6.122
	665.263	60.875	3051.283	6.135
RE S.H. OUT	813.981	60.875	3410.537	6.623
IP TURB IN	813.160	58.917	3410.537	6.638
LP TURB OUT	318.345	.097	2312.374	7.272
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.351	66.287	92.750	.279
GEO FWH IN	320.351	64.563	92.748	.280
GEO FWH OUT	420.313	64.563	515.076	1.430
REGEN HTR IN	420.313	62.840	515.078	1.430
BLEED STEAM IN	666.725	62.840	3051.283	6.122
COOLING WATER				
PUMP IN	300.175	.900	8.463	.028
PUMP OUT	300.257	3.700	8.806	.028
COND. OUT	315.076	3.700	70.717	.229
COOL TOWER IN	315.076	.900	70.716	.230
COOL TOWER OUT	300.175	.900	8.463	.028
COOLING AIR				
TOWER IN	308.716	.900	26.401	1.424
TOWER OUT	310.000	.900	125.822	.069
MAKEUP WATER	299.827	.900	7.010	.023
GEO WATER				
FWH IN	433.160	6.200	570.708	1.575
FWH OUT	330.751	6.200	136.209	.432

Table D3b
Optimized State Points: Long Valley - 750 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	96.001	13.053	49.558	.105
AIR				
PREHEAT IN	96.001	13.053	49.558	.105
PREHEAT OUT	420.305	13.053	127.305	.215
FLUE GAS				
S.H. IN	3734.312	13.053	1164.844	.726
RE S.H. IN	2604.982	13.053	819.052	.630
BOIL/ECON IN	2256.782	13.053	712.436	.593
PREHEAT IN	641.367	13.053	217.807	.316
STACK OUT	411.214	13.053	147.336	.245
WORKING FLUID				
BFP IN	533.311	911.423	528.109	.731
BFP OUT	541.361	2947.810	538.182	.733
	541.361	2867.691	538.181	.733
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	740.417	911.423	1357.157	1.552
RE S.H. IN	740.417	911.423	1357.157	1.552
	737.786	882.923	1357.157	1.555
RE S.H. OUT	1005.477	882.923	1511.649	1.672
IP TURB IN	1004.000	854.525	1511.649	1.675
LP TURB OUT	113.332	1.407	1039.402	1.827
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	116.944	961.418	84.889	.156
GEO FWH IN	116.943	936.413	84.888	.156
GEO FWH OUT	296.875	936.413	266.503	.431
REGEN HTR IN	296.876	911.423	266.504	.431
BLEED STEAM IN	740.417	911.423	1357.157	1.552
COOLING WATER				
PUMP IN	80.626	13.053	48.642	.096
PUMP OUT	80.774	53.664	48.790	.096
COND. OUT	107.448	53.664	75.414	.144
COOL TOWER IN	107.448	13.053	75.413	.144
COOL TOWER OUT	80.626	13.053	48.642	.096
COOLING AIR				
TOWER IN	96.001	13.053	56.356	.430
TOWER OUT	98.312	13.053	99.111	.106
MAKEUP WATER	80.001	13.053	48.018	.095
GEO WATER				
FWH IN	320.000	89.924	290.427	.466
FWH OUT	135.664	89.924	103.577	.193

Fig. D1--Temperature-Entropy Chart: Optimized Long Valley - 750 MW

Table D4
Optimized Mass Flow Rates: Long Valley - 750 MW

	(KG/SEC)	(KLB/HR)
COAL	76.90896	610.39877
COMBUSTION AIR	744.90603	5912.05102
FLUE GAS	821.81500	6522.44978
WORKING FLUID HP	746.10596	5921.57439
WORKING FLUID LP	567.14436	4501.22058
WORKING BLEED STEAM	178.96160	1420.35381
COOLING WATER	20410.01636	161986.95225
COOLING AIR	12830.28676	101829.36710
MAKEUP WATER	511.07242	4056.19781
GEO WATER	551.25801	4375.13635

Table D5
Summary Costs: Optimized Long Valley - 250 MW
(all figures in 1976 dollars)

COMPONENT	1976 COST (M\$)	
LAND	.520	
STRUCTURE	25.756	
STATION ELECTRICAL AND ACCESSORY EQUIP.	5.692	
INDUSTRIAL WASTE EQUIP.	.491	
MISC. EQUIP.	6.808	
COAL HANDLING EQUIP.	3.668	
BOILER NO. 1	50.379	
CONDENSER NO. 1	.554	
H.P. TURBINE/GENERATOR NO. 1	14.890	
GEOHERMAL FEEDWATER HEATER NO. 1	2.658	
PUMP NO. 1	.070	
PUMP NO. 2	.268	
PUMP NO. 3	.096	
(1) COOLING TOWER(S)	3.844	
(4) GEOHERMAL WELL(S)	4.872	
TOTAL PHYSICAL PLANT		120.563
CONSTRUCTION LABOR/MANAGEMENT	34.561	
TOTAL INITIAL PLANT		155.124
OBJECTIVE FUNCTION:		
CAPITAL COST OF POWER:	\$ 620.498/KW	

Table D6

Time Dependent Costs: Optimized Long Valley - 250 MW

(all figures in 1976 dollars)

CAPACITY FACTOR	85.00 %		
PLANT LIFE	30.00 YEARS		
CONSTRUCTION TIME	4.00 YEARS		
BOND INTEREST RATE	6.00 %		
INFLATION RATE	5.00 %		
O/M GROWTH RATE	5.00 %		
COAL COST GROWTH RATE	8.00 %		
CONSTRUCTION LABOR RATE	28.67 %		
PLANT O/M RATE	4.00 %		
WELL O/M RATE	17.00 %		
SEISMIC FACTOR	103.00 %		
COAL COST (\$/TONNE: 1976)	\$ 33.06		
WELL HALF-LIFE	10.00 YEARS		
WELL REPLACEMENT RATE	.06697 (WELLS/YEAR)/WELL		
WELL COST OF FLOW	\$ 25.371 /(LB/HR)		
CONSTRUCTION COST FACTOR	1.0269435		
BOND INTEREST COST FACTOR	.9187874		
NET CAPITAL FACTOR	.9435428		
AVG. ANNUAL CAPITAL FACTOR	.0314514		
AVG. ANNUAL COAL COST FACTOR	1.7591513		
AVG. ANNUAL CAPITAL COST	4.879	2.6192	
AVG. ANNUAL PLANT O/M COST	4.929	2.6460	
AVG. ANNUAL WELL COST	.271	.1453	
AVG. ANNUAL WELL O/M COST	.828	.4446	
AVG. ANNUAL COAL COST	39.851	21.3939	
AVG. ANNUAL COOLING WATER COST	.463	.2488	
TOTAL AVG. ANNUAL COST	51.221	27.4979	
OBJECTIVE FUNCTION:			
BUSBAR COST:	27.4979 MILS/KWH		
TRANSMISSION COST:	3.0000 MILS/KWH		
COST OF POWER:	30.4979 MILS/KWH		

Table D7a
Optimized State Points: Long Valley - 250 MW

	T (DEG K)	P (BAR)	H (J/G)	S (J/GK)
COAL IN	308.716	.900	10.591	.065
AIR				
PREHEAT IN	308.716	.900	10.591	.065
PREHEAT OUT	494.233	.900	196.750	.537
FLUE GAS				
S.H. IN	2333.333	.900	2608.943	2.667
RE S.H. IN	1705.729	.900	1804.400	2.265
BOIL/ECON IN	1510.690	.900	1554.375	2.109
PREHEAT IN	611.483	.900	401.656	.950
STACK OUT	479.855	.900	232.918	.639
WORKING FLUID				
BFP IN	551.252	62.329	1121.285	2.682
BFP OUT	555.744	203.244	1144.761	2.690
	555.744	197.720	1144.759	2.692
S.H. IN	641.347	197.720	2413.759	4.731
	629.889	179.346	2413.759	4.752
S.H. OUT	818.157	179.346	3299.460	6.025
HP TURB IN	813.160	166.487	3299.460	6.055
HP TURB OUT	665.631	62.329	3049.418	6.122
RE S.H. IN	665.631	62.329	3049.418	6.122
	664.162	60.364	3049.418	6.136
RE S.H. OUT	813.981	60.364	3411.036	6.628
IP TURB IN	813.160	58.406	3411.036	6.642
LP TURB OUT	318.345	.097	2313.555	7.275
COND. PUMP IN	318.345	.097	84.369	.274
COND. PUMP OUT	320.336	65.776	92.687	.279
GEO FWH IN	320.336	64.052	92.685	.280
GEO FWH OUT	420.584	64.052	516.245	1.433
REGEN HTR IN	420.584	62.329	516.247	1.433
BLEED STEAM IN	665.631	62.329	3049.418	6.122
COOLING WATER				
PUMP IN	299.862	.900	7.155	.024
PUMP OUT	299.944	3.700	7.499	.024
COND. OUT	315.489	3.700	72.444	.235
COOL TOWER IN	315.489	.900	72.443	.236
COOL TOWER OUT	299.862	.900	7.155	.024
COOLING AIR				
TOWER IN	308.716	.900	26.401	1.424
TOWER OUT	309.992	.900	125.758	.069
MAKEUP WATER	299.827	.900	7.010	.023
GEO WATER				
FWH IN	433.160	6.200	570.708	1.575
FWH OUT	332.911	6.200	145.239	.459

Table D7b
Optimized State Points: Long Valley - 250 MW

	T (DEG F)	P (PSIA)	H (BTU/LB.)	S (BTU/F-LB)
COAL IN	96.001	13.053	49.558	.105
AIR				
PREHEAT IN	96.001	13.053	49.558	.105
PREHEAT OUT	429.931	13.053	129.612	.218
FLUE GAS				
S.H. IN	3740.312	13.053	1166.936	.726
RE S.H. IN	2610.625	13.053	820.956	.631
BOIL/ECON IN	2259.555	13.053	713.436	.593
PREHEAT IN	640.981	13.053	217.728	.316
STACK OUT	404.051	13.053	145.166	.242
WORKING FLUID				
BFP IN	532.566	904.014	527.193	.730
BFP OUT	540.651	2947.810	537.289	.732
	540.651	2867.691	537.288	.732
S.H. IN	694.736	2867.691	1083.000	1.220
	674.112	2601.199	1083.000	1.225
S.H. OUT	1012.994	2601.199	1463.881	1.529
HP TURB IN	1004.000	2414.694	1463.881	1.536
HP TURB OUT	738.449	904.014	1356.355	1.552
RE S.H. IN	738.449	904.014	1356.355	1.552
	735.804	875.514	1356.355	1.555
RE S.H. OUT	1005.477	875.514	1511.863	1.673
IP TURB IN	1004.000	847.116	1511.863	1.676
LP TURB OUT	113.332	1.407	1039.909	1.827
COND. PUMP IN	113.332	1.407	81.285	.155
COND. PUMP OUT	116.917	954.009	84.862	.156
GEO FWH IN	116.916	929.004	84.861	.156
GEO FWH OUT	297.363	929.004	267.006	.432
REGEN HTR IN	297.364	904.014	267.007	.432
BLEED STEAM IN	738.449	904.014	1356.355	1.552
COOLING WATER				
PUMP IN	80.063	13.053	48.080	.095
PUMP OUT	80.211	53.664	48.228	.095
COND. OUT	108.193	53.664	76.157	.146
COOL TOWER IN	108.193	13.053	76.156	.146
COOL TOWER OUT	80.063	13.053	48.080	.095
COOLING AIR				
TOWER IN	96.001	13.053	56.356	.430
TOWER OUT	98.297	13.053	99.083	.106
MAKEUP WATER	80.001	13.053	48.018	.095
GEO WATER				
FWH IN	320.000	89.924	290.427	.466
FWH OUT	139.551	89.924	107.461	.199

Fig. D2--Temperature-Entropy Chart: Optimized Long Valley - 250 MW

Table D8

Optimized Mass Flow Rates: Long Valley - 250 MW

	(KG/SEC)	(KLB/HR)
COAL	25.54970	202.77881
COMBUSTION AIR	247.46308	1964.02536
FLUE GAS	273.01278	2166.80416
WORKING FLUID HP	247.99631	1968.25741
WORKING FLUID LP	188.76334	1498.14664
WORKING BLEED STEAM	59.23297	470.11077
COOLING WATER	6479.10997	51422.36331
COOLING AIR	4274.34557	33923.94203
MAKEUP WATER	170.16410	1350.53121
GEO WATER	187.91672	1491.42737

Appendix E

INTERMOUNTAIN POWER PROJECT (IPP)

-961-

DESIGN ENGINEER ROBERT B. SIMAN

REVISION DATE 1-23-13

SKETCH NO. MA 31

Fig. E1--Heat Balance: Intermountain Power Project

Fig. E2--Temperature-Entropy Chart: Intermountain Power Project

Appendix F

Hybrid Fossil-Geothermal Power Plants

by

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Abstract:

In this article we introduce the so-called hybrid concept for the simultaneous conversion of high- and low-grade thermal energy into work. In particular, we consider hybrid fossil-geothermal systems in which the low-grade geothermal energy is used for preheating the working fluid in a power cycle at lower temperatures while the high-grade energy derived from a fossil fuel is utilized for heating in the higher temperature range. In this manner the entropy production associated with the poor utilization of geothermal energy in a binary-fluid or a flash system is reduced.

The performance of the hybrid system is analyzed through the introduction of a number of figures of merit. It is shown that from a thermodynamic viewpoint the hybrid system is superior to a combination of two individual state-of-the-art systems, one for the fossil energy and the other for the geothermal energy. This is evidenced by the ability of hybrid systems to generate more work than would be possible in individual plants. A geothermal resource of 200°C (392°F) well-head temperature can be utilized for low temperature feedwater heating in a hybrid plant to produce about 50% more work than a state-of-the-art binary-fluid or flash plant utilizing the same resource. This is achieved while producing an additional amount of work equal to that which would be produced by burning the same amount of fossil fuel in a state-of-the-art steam power plant. At a wellhead temperature of about 200°C it is expected that the hybrid plant will have about 10 times the capacity of a purely geothermal plant utilizing the same source.

It is recognized that geothermal fluids at relatively low temperatures ($< 150^{\circ}\text{C} \approx 302^{\circ}\text{F}$) are below the limit of usefulness for the production of electricity in binary-fluid or flash systems and that such fluids are wasteful in space-heating applications. Thus, it is emphasized that the hybrid arrangement possesses the important advantage of being able to utilize such marginal geothermal resources to produce electricity.

1. Introduction:

The rapidly growing dependence of the United States on imported oil has created an overwhelming concern over the need for a comprehensive policy aiming at energy self-sufficiency. Such a policy can be implemented only by utilizing all the energy sources available in the country and by adopting research and development policies that will eventually lead to the fulfillment of such goal. Fossil fuels will remain the nation's main energy source for the foreseeable future, and other energy sources will complement, rather than replace, fossil fuels in order to satisfy the growing need for energy. Within this framework, geothermal energy appears to be a viable partial solution of the energy crisis.

Geothermal energy is presently utilized for electric power generation at The Geysers fields in northern California with a current installed capacity of 522 MW. The Geysers fields constitute only a minute fraction of the geothermal energy potentials in the U.S. [1]. Excluding the geopressured and hot rock reservoirs, Ref. [1] quotes a figure of 4.6×10^6 MW yr available for conversion to electricity from the hydrothermal systems in the western U.S. alone. This estimate includes all hydrothermal resources, discovered and undiscovered whose temperature exceeds 150°C. On the basis of the identified resources alone, the figure drops to about 8×10^5 MW yr[#] which is still enormous. It should be emphasized, however, that most of these resources are of the liquid-dominated variety as opposed to the vapor-dominated Geysers fields.

Vapor-dominated geothermal resources can be utilized without any significant extrapolation of present-day steam power plant technology. For

[#]This is equivalent to the output of 27 power plants each of 1000 MW capacity over a period of 30 years.

example, geothermal steam has been utilized for electric power generation at the Larderello fields in Italy since 1904 [2, 3]. However, the fact that most of the identified hydrothermal systems in the continental U.S. are of the liquid-dominated type constitutes a manifold of problems in utilization technologies.

Several systems have been proposed for converting geothermal energy into electric energy, notably; the flash system, the binary system and the total flow system [4, 5, 6]. These systems are schematically illustrated in Fig. 1. The common denominator in all these systems is the reliance on the geofluid as the sole source of raw energy. The total flow system appears to be the simplest and most attractive from a conceptual point of view. From a practical point of view, however, this system is still technically and economically unfeasible owing to the lack of an efficient and economical total flow expander capable of handling two-phase, highly corrosive fluids [6, 7]. Accordingly, we shall adopt the view that the flash and binary systems constitute the present state of the art in the utilization of liquid-dominated geothermal resources. Both these systems, however, pay a thermodynamic penalty arising from the inferior grade of geothermal energy available in liquid-dominated wells; namely, the geofluid cannot be utilized without considerable entropy production. With reference to the temperature-entropy (T-s) diagrams accompanying Fig. 1, it can be seen that the source of this entropy production lies primarily in the throttling processes that are part of the flash system (process $b \rightarrow l$, Fig. 1 (a)), and in the transfer of heat with a large average temperature difference between the geofluid and the working fluid in the binary system (processes $b \rightarrow r$ and $4 \rightarrow 1$, Fig. 1 (b).)

In this paper we present the so-called hybrid (fossil-geothermal) system which we will show avoids the major sources of entropy production mentioned above and offers a thermodynamic advantage over both the flash and the binary systems.

2. The hybrid concept:

In a conventional steam power cycle, fuel is burned at a high temperature to supply heat to the feedwater which enters the steam generator at a considerably lower temperature. Such a high temperature difference results, inevitably, in large entropy production and a reduction in the overall plant efficiency. Various arrangements have been devised to reduce the average temperature difference during the heat addition process; notably, regenerative feedwater heating, reheating and clever arrangement of the heating surfaces in the steam generator.

The hybrid concept is proposed as a means of utilizing two heat sources; one at high temperature such as the combustion products in the furnace of a steam generator and the second at a lower temperature such as the brine obtained from a geothermal reservoir or the waste heat from another plant [8]. Figure 2 shows a simplified hybrid arrangement in which a geothermal brine is utilized for heating the working fluid from the condenser temperature up to a maximum temperature determined by the temperature of the brine. The working fluid is further heated, evaporated and superheated in a conventional steam generator (SG). In this manner, the working fluid receives an amount of heat Q_g from the geothermal source and an amount Q_f from the fossil fuel while producing net work W (See Fig. 3(a)).

Naturally, for the hybrid system to be a viable alternative to other utilization systems, it has to demonstrate an overall economic advantage over them. In what follows we investigate the potential of the hybrid arrangement as an energy conversion system.

3. Analysis of hybrid systems:

Since the hybrid system utilizes two energy sources each of which could be utilized individually in a state-of-the-art plant, the performance of a hybrid system should be judged in comparison with the best that can be done with the two individual sources. The situation is illustrated schematically in Fig. 3 which shows a hybrid system contrasted with two individual conventional systems; a state-of-the-art fossil-fuel steam power plant, F^* , and a state-of-the-art geothermal plant, G^* . The fossil plant receives an amount of fossil heat, Q_f , produces work W_f^* while running at an efficiency $\eta_f^* = W_f^*/Q_f$. Similarly, the geothermal plant receives an amount of geothermal heat Q_g and produces work W_g^* at an efficiency $\eta_g^* = W_g^*/Q_g$. On the other hand, had the two heat inputs Q_f and Q_g been utilized in the hybrid plant, an amount of work W would have been obtained at an efficiency η :

$$\eta = W/(Q_f + Q_g) . \quad (1)$$

This enables us to define a figure of merit F which determines whether the hybrid system produces more or less work than the two separate systems; namely,

$$F \equiv W/(W_f^* + W_g^*) . \quad (2)$$

Obviously our aim is to choose hybrid systems for which the figure of merit, F , is greater than unity. If we introduce the geothermal heat fraction,

$$\phi \equiv Q_g/Q_f , \quad (3)$$

and utilize eqn. (1) together with the definitions of η_f^* and η_g^* , we obtain

$$F = (1+\phi) \eta / (\eta_f^* + \phi \eta_g^*) . \quad (4)$$

The quantities ϕ , η and η_g^* are functions of the temperature T_g to which the working fluid can be heated by means of the geofluid. Equivalently, η and η_g^* are functions of ϕ which is a function of T_g . Consequently we can write

$$F(\phi) = (1+\phi) \eta(\phi) / \left[\eta_f^* + \phi \eta_g^*(\phi) \right] , \quad (4a)$$

$$\phi = \phi(T_g) . \quad (4b)$$

The specific dependence of η_g^* and η on ϕ and of ϕ on T_g deserves some attention. The efficiency of a state-of-the-art geothermal plant can best be analyzed in terms of the concept of the maximum available work, w_g^0 [9]. For a geothermal brine at a temperature T_b and a dead-state (sink) temperature T_o we can write

$$w_g^0 = h_b - h_o - T_o (s_b - s_o) , \quad (5)$$

where h and s are the specific enthalpy and specific entropy respectively, and w_g^0 is the maximum available work per unit mass of brine. Equation (5) contains the inherent assumption that it is always possible to bring the fluid down to the dead state (o). Such an assumption is practically impossible. In realistic situations, the brine is cooled down to a temperature T_r , higher than T_o , at which it is reinjected into the ground. Consequently, we introduce the available work $\bar{w}_g^0$ [3] defined as:

$$\bar{w}_g^0 = h_b - h_r - T_o (s_b - s_r) , \quad (8)$$

indicated by the cross-hatched area on the T - s diagram of Fig. 4. From a purely thermodynamic point of view, the maximum efficiency η_g^0 of a heat engine receiving an amount of heat q_g per unit mass of brine from the geothermal source is:

$$\eta_g^0 \equiv w_g^0 / q_g = 1 - T_o (s_b - s_o) / (h_b - h_o) , \quad (7)$$

in which we put $q_g = h_b - h_o$. If we take the work loss at reinjection into account we arrive at

$$\bar{\eta}_g^o = \bar{w}_g^o / \bar{q}_g = 1 - T_o (s_b - s_r) / (h_b - h_r) , \quad (8)$$

in which we put $\bar{q}_g = h_b - h_r$. Due to the various sources of entropy production in actual systems, the amount of work that can be obtained from the geothermal source is reduced, i.e.

$$w_g^* = \bar{w}_g^o - T_o \theta , \quad (9)$$

where θ is the total entropy production in the plant. We express this work loss by introducing a utilization efficiency η_u such that

$$w_g^* = \eta_u \bar{w}_g^o , \quad (10a)$$

or

$$\eta_g^* = \eta_u \bar{\eta}_g^o . \quad (10b)$$

It is worth noting that

$$\lim_{T_b \rightarrow T_r} \bar{\eta}_g^o = 1 - T_o / T_r . \quad (11)$$

Since the geofluid behaves, in most practical applications, as an incompressible fluid with a constant specific heat c , Equations (6) and (8) can be written as:

$$\bar{w}_g^o = c [(T_b - T_r) - T_o \ln (T_b / T_r)] , \quad (6a)$$

and

$$\bar{\eta}_g^o = 1 - [T_o \ln (T_b / T_r)] / (T_b - T_r) . \quad (8a)$$

Figure 5 shows the efficiency $\bar{\eta}_g^o$ computed on the basis of equation (8) for pure water when $T_o = 25^\circ\text{C}$ and $T_r = 45^\circ\text{C}$. The dashed line represents the

efficiency η_g^o calculated on the basis of Equation (7), also for pure water.

In order to study the dependence of η on ϕ and of ϕ on T_g we need to specify the steam power cycle which will serve as the basis of the hybrid plant.

4. Selection of an appropriate cycle

In modern steam power stations, cycle thermal efficiencies of 43 - 44% (i.e. $\eta_f^* = 0.43 - 0.44$) are achieved. This was made possible by using steam of high initial parameters, by the adoption of reheat and regenerative feed-water heating principles and by systematically improving the efficiency of the individual components [10]. Figure 6 shows a schematic flow diagram of a typical modern steam power plant with two reheat stages and seven feedwater heaters. A certain amount of fossil heat Q_f can always be utilized in such a state-of-the-art plant to produce work at an efficiency η_f^* . From an energy utilization viewpoint, any new system proposed for utilizing Q_f , either in part or in full, should at least do so as efficiently as a modern fossil-fueled steam power plant. This imposes certain limitations on the choice of the type of steam cycle for a hybrid plant. An examination of Equation (4) will help clarify the nature of these limitations as can be shown by a specific example. We assume that $T_b = 200^\circ\text{C}$ and that $\eta_f^* = 0.435$; the limiting value of η corresponds to putting $F = 1$:

$$\eta_{\text{lim}} = (\eta_f^* + \phi \eta_g^*) / (1 + \phi) \quad . \quad (12)$$

Assuming a utilization efficiency $\eta_u = 0.7$ and using the values of $\bar{\eta}_g^o$ from Fig. 5, we obtain

$$\eta_g^* (T_b = 200^\circ\text{C}) = 0.167 \quad . \quad (12a)$$

The variation of $\eta_{\text{lim}}/\eta_f^*$ with ϕ is shown in Fig. 7 for the example chosen; the corresponding curves for $T_b = 150^\circ\text{C}$ and 250°C are also shown for comparison. The existence of a lower limit of efficiency suggests that the choice of a cycle for the hybrid system is not arbitrary. Figure 7 shows that suitable cycles should not be much inferior to the state-of-the-art steam power cycles.

It should be born in mind that even if we start with a cycle identical to the state-of-the-art cycle, replacing some regenerative feedwater heating with geothermal heating represents a thermodynamic penalty. This is attributable to the fact that regenerative feedwater heating is responsible for a significant portion of the improvement in the efficiency of modern steam cycles over the basic Rankine cycle [11]. Consequently, cycles that derive all their efficiency improvement from regenerative feedheating[#] will suffer the highest thermodynamic penalty in a hybrid arrangement. Taken to the extreme, this penalty may wipe out all the advantages of the hybrid concept. Fortunately, modern steam cycles have one or two reheat stages and use only seven or eight feedwater heaters. This limits the extent of the thermodynamic penalty incurred in a hybrid arrangement and results in a wide range of conditions under which a gain can be realized (i.e., $F > 1$). Alternatively, the rolloff in the efficiency η of a hybrid plant which is based on a modern high efficiency steam cycle is most likely to be less steep than the limiting curves of Fig. 7.

The fractional contribution, ϕ , of the geothermal source to the overall heat input is determined primarily by the brine temperature T_b . In order to accommodate a brine heat exchanger in the feed loop of the steam cycle, the final feedwater temperature, T_f , should be at least as high as T_g which is only slightly lower than T_b . Modern high pressure steam power stations operate with T_f as high as 300°C ^{##} [10, 12], whereas most liquid-dominated geothermal sources have wellhead temperatures considerably lower than 300°C [1]. Consequently, it is almost always possible to find a cycle arrangement compatible with a particular geothermal site.

[#]Such as non-reheat cycles with a large number of feedwater heaters.

^{##}The flue gases in the steam generator are further cooled in the economizer and the air preheater down to a stack temperature of about 150°C in order to maintain a high steam generator efficiency.

Figure 8 shows a flow diagram of a hybrid arrangement based on the conventional steam cycle of Fig. 6. The important conventional cycle parameters are given in Table I for two typical arrangements; one subcritical with a single reheat and seven feedwater heaters and the other supercritical with a double reheat and seven feedwater heaters. No attempt has been made to optimize the bleed or the reheat pressures beyond the application of recognized practices [10, 11, 13].

5. Performance of hybrid systems

The figure of merit F has been introduced as a measure of the comparative performance of a hybrid system with respect to individual utilization methods. In the definition of F , however, it is implied that both Q_f and Q_g are available at the same unit cost. In order more realistically to assess the relative merit of the hybrid system we have to admit that Q_f and Q_g may not have the same unit cost. If we introduce a geothermal heat equivalence factor ξ that accounts for the difference in unit cost we obtain the adjusted figure of merit

$$F_{\xi} = (1+\phi) \eta / (\eta_f^* + \xi \phi \eta_g^*) . \quad (13)$$

The figure of merit F is obtained from F_{ξ} when $\xi = 1$, i.e. when the cost of a unit of geothermal heat is equivalent to the cost of a unit of fossil heat. Moreover, since a hybrid power plant has to be built on or very near the geothermal field, which may not be the optimum site for a fossil power plant, an additional modification of the figure of merit should be introduced. Therefore we define an economic figure of merit F_e as

$$F_e = \gamma (1+\phi) \eta / (\eta_f^* + \xi \phi \eta_g^*) , \quad (14)$$

in which ξ is a measure of the cost of geothermal heat relative to that of fossil heat delivered at the power plant site, and γ is a measure of the fossil heat cost adjustment due to the site limitations. The factor γ can only be determined for specific sites and may differ widely from one site to another. Further it is conceivable that γ may be either greater than or less than unity although its value will generally be close to unity. In the analysis to follow, we shall adopt a value of $\gamma = 1.0$, thus making F_e identical with F_{ξ} .

The economic figures of merit, F_e , for the two cycles described in the previous section has been evaluated for a range of brine temperatures T_b extending from a reinjection temperature $T_r = 45^\circ\text{C}$ up to a maximum determined by the final feedwater temperature, T_f . In all cases, a constant temperature difference was maintained in the brine heat-exchanger. The seven feedwater heaters in the conventional cycle were replaced one at a time with geothermal heating in the brine heat-exchanger. For each step, k , we computed the quantity ϕ and the hybrid cycle efficiency

$$\eta(k) = 1 - (h_e - h_c) \left[1 - \sum_{i=k+1}^N m_i \right] / (Q_f + Q_g) \quad , \quad (15)$$

in which h_e is the specific enthalpy at the turbine exhaust, h_c is the specific enthalpy in the hot well of the condenser, m_i the fraction of steam bled for regenerative heating in feedwater heater i and N is the total number of feedwater heaters in the original cycle. Moreover,

$$Q_g(k) = \left[1 - \sum_{i=k+1}^N m_i \right] (h_g - h_c) \quad (16a)$$

where h_g is the specific enthalpy to which the feedwater is heated in the brine heat exchanger. Therefore

$$\phi(k) = \left[1 - \sum_{i=k+1}^N m_i \right] (h_g - h_c) / Q_f \quad (16b)$$

Figure 9 illustrates the dependence of both η/η_f^* and ϕ on $T_g^\#$ for both the subcritical and the supercritical cycles. Figure 10 depicts the relationships between η/η_f^* and ϕ for both cycles together with the mass flow rate at the turbine exhaust flange:

[#] $T_g = T_b - (T_r - T_c)$ as necessitated by the constancy of the temperature difference in the brine heat exchanger.

$$m_e(k) = 1 - \sum_{i=k+1}^N m_i, \quad (17a)$$

normalized with respect to the same quantity for the conventional steam cycle:

$$m_e^* = 1 - \sum_{i=1}^N m_i. \quad (17b)$$

The quantity m_e/m_e^* is practically indistinguishable for the subcritical and the supercritical cycles. It should be noted that the values of η/η_f^* corresponding to any particular brine temperature ($T_b = 150, 200$ or 250°C) lie above the corresponding limiting curves of Fig. 7.

Figures 11 and 12 show the economic figure of merit, F_e , for the subcritical and the supercritical cycles respectively. The solid lines are computed on the basis of a value of $\eta_u = 0.7$ whereas the dashed lines are for $\eta_u = 0.6$. The latter value is more representative of the present state-of-the-art technology in geothermal energy utilization. On the basis of these results we conclude that the hybrid system is more advantageous than the individual utilization systems even when the unit cost of geothermal heat is somewhat higher than that of the fossil heat delivered at the plant site. This is a consequence of the fact that F_e acquires values that are greater than unity even with values of ξ as high as 1.5.

6. Other performance parameters

In the previous section we have established the potential of the hybrid system for improved combined utilization of the two sources. If we postulate that no more than $W_f^* = \eta_f^* Q_f$ was contributed by the fossil heat to the net work output W of the hybrid system, then the amount of work that may be attributed to Q_g is

$$W_g = W - W_f^* . \quad (18)$$

Since a separate geothermal plant utilizing the same source can, at best, produce W_g^* as mentioned earlier, we define a geothermal figure of merit F_g as

$$F_g = W_g / W_g^* . \quad (19)$$

In terms of η_f^* , η_g^* and ϕ this reduces to

$$F_g = [\eta (1+\phi) - \eta_f^*] / (\phi \eta_g^*) . \quad (20)$$

It is interesting to investigate the behavior of this function in the two limiting cases of $\phi \rightarrow 0$ (i.e. brine is available at the point of nonusefulness, $T_b = T_r$) and $\phi \rightarrow \infty$ (i.e. brine temperature is high enough to eliminate the need for fossil fuel). We realize, however, that the latter limit will probably never be approached in practice.

The behavior of F_g as $\phi \rightarrow 0$ becomes indeterminate (0/0) since

$$\lim_{\phi \rightarrow 0} \eta = \eta_f^* , \quad (21)$$

while η_g^* approaches the finite value given by (11). However, if we expand $\eta(\phi)$ in powers of ϕ we obtain

$$\eta(\phi) = \eta_f^* (1 - \alpha\phi \dots) . \quad (22)$$

Substituting in (20) and going to the limit ($\phi \rightarrow 0$):

$$\lim_{\phi \rightarrow 0} F_g = (1-\alpha) \eta_f^* / (1-T_o/T_r) . \quad (23)$$

We recognize that the denominator of eqn. (23) is the efficiency of a Carnot cycle operating between T_r and T_o .

It can easily be seen that the other limiting case ($\phi \rightarrow \infty$), which corresponds to $Q_f = 0$, leads to the result

$$\lim_{\phi \rightarrow \infty} F_g = 1 . \quad (24)$$

This follows from the fact that $W_g \rightarrow W \rightarrow W_g^*$ when $Q_f = 0$, or alternatively, the hybrid system reduces to a purely geothermal system.

Figure 13 shows the geothermal figure of merit as a function of T_b . It is evident that the utilization of geothermal energy in a hybrid system has a considerable advantage over utilizing it separately in a flash or a binary system, especially if the highest utilization efficiency for either of the latter two systems remains at or below 0.6. In order for a separate geothermal plant to produce the same amount of work attributable to the geothermal part of hybrid system, its utilization efficiency η_u must be higher than a limiting (threshold) value η_u^* . This threshold value can be obtained by substituting $\eta_g^* = \eta_u \bar{\eta}_g^o$ in Eqn. (4) and setting $F = 1$:

$$\eta_u^* = [(1+\phi) \eta - \eta_f^*] / \phi \bar{\eta}_g^o . \quad (25)$$

The behavior of η_u^* as a function of T_b is shown in Fig. 14 for both the subcritical and the supercritical cycles. It can be seen that the threshold value of η_u at $T_b = 200^\circ\text{C}$ is in excess of 96% for the supercritical cycle and about 87% for the subcritical cycle. It is recalled that the present state-of-the-art in geothermal energy utilization provides values of η_u of

0.6-0.7 at most. The threshold values given above are obviously not within the realm of the current state-of-the-art.

Another important performance parameter is the ratio of the work output of the hybrid plant to the maximum work output of a purely geothermal plant utilizing the same source ($\bar{W}_g^0$). As a measure of this quantity we introduce the work amplification factor ψ defined by

$$\psi = W / \bar{W}_g^0. \quad (26)$$

In terms of η , ϕ and $\bar{\eta}_g^0$ this becomes

$$\psi = \eta(1+\phi) / \phi \bar{\eta}_g^0. \quad (27)$$

Figure 15 shows the dependence of the work amplification factor ψ on T_b . On the basis of this graph we can see that if a geothermal source at 200°C can develop a maximum of, say, 50 MW, a hybrid plant utilizing the same geothermal source will have a capacity of about 500 MW. Of course, one must estimate the mass flow rate of the geofluid before the available power of the geothermal source can be calculated.

The arguments used in introducing the geothermal figure of merit F_g can be reversed in order to introduce still another performance parameter, viz the fossil energy utilization factor $\bar{\eta}_f$. In this case we attribute an amount of work

$$W_f = W - W_g^* \quad (28)$$

to the fossil heat Q_f . In other words, we assume that the geothermal heat Q_g has been utilized in the hybrid plant at a level equal to the current state of the art in geothermal energy utilization. Under these conditions Q_g produces at most an amount of work W_g^* , the balance of the work W_f being attributed to Q_f .

The fossil energy utilization factor is defined as

$$F_f = W_f / W_f^* \quad (29)$$

or, in terms of ϕ , η and η_g^* ,

$$F_f = \left[(1+\phi) \eta - \phi \eta_g^* \right] / \eta_f^* \quad (30)$$

It is noted that $F_f \rightarrow 1$ as $\phi \rightarrow 0$. The limit as $\phi \rightarrow \infty$ is of no practical importance since in this case the hybrid plant becomes merely a purely geothermal plant with no dependence on fossil fuel.

The behavior of F_f as a function of T_b is illustrated in Fig. 16 for both the subcritical and the supercritical cycles. It can be seen that the same amount of fossil fuel produces more work in the hybrid plant than it would in a state-of-the-art fossil power plant. This improvement is achieved while utilizing the geothermal energy at the highest level of available or contemplated technology ($\eta_u = 0.7$). At $T_b = 200^\circ\text{C}$, for example, 2-3% more work can be attributed to the fossil fuel than would have been possible by burning the same amount in a state-of-the-art steam power plant.

7. Concluding remarks:

We have demonstrated the potential advantages of the hybrid system over individual utilizations of the fossil energy and geothermal energy. The hybrid plant, however, has to be constructed in the geothermal site which may not be the optimum site with regards to the transportation of the fossil fuel and the transmission of the electrical energy. These aspects have to be studied for each individual case.

The hybrid plant produces more power per unit mass flow of the working fluid (steam) since the elimination of some of the feedwater heaters results in an increased mass flow in the low pressure turbine as can be seen in Fig. 10. On the other hand, such an increased mass flow rate has the adverse side effect of increasing the size of the low pressure turbine. Obviously, in an economic analysis of the hybrid system, those two effects have to be weighed against one another. With the exception of the brine heat exchanger, all the components of the hybrid plant are standard steam power plant equipment; this means that hybrid power plants can be implemented with a minimum extrapolation of present state-of-the-art steam power plant technology. The cost of the brine heat exchanger has to be considered in relation to the cost saving effected by the elimination of some of the feedwater heaters. The cost of the brine heat exchanger in the hybrid system is not expected to be much different from that in a binary plant utilizing the same geothermal source. In the latter case, the cost of the organic fluid turbine should be compared with the added cost of the low pressure turbine in the hybrid system.

To sum up the above considerations we note that:

- 1) The increased mass flow rate in the low pressure turbine of a hybrid system results in a more expensive machine but also results in a higher specific

output. The additional output, W_g , is greater than the output of a binary plant utilizing the same geothermal source to produce work, W_g^* , through the expansion of an organic working fluid (fluoro and hydrocarbons) in a vapor turbine. The cost of this turbine per unit output should be compared with the additional cost of the larger low pressure steam turbine per unit additional output.

2) The increased mass flow at the low pressure and of the steam turbine in the hybrid system will result in a larger condenser. The additional cost of the enlarged steam condenser (relative to that of a conventional fossil plant) should be compared with the cost of the organic-fluid condenser in the binary system.

3) The cost of the brine heat exchanger in the hybrid plant minus the cost of the eliminated feedwater heaters should be compared with the cost of the brine heat exchanger in the binary plant.

4) Finally the cost of providing for proper handling and make-up of the organic working fluid in the binary plant should be compared with the relatively low cost of supplying make-up water in the hybrid plant.

It is generally agreed that geothermal resources of temperatures below 150°C ($W_g^o < 88 \text{ kJ/kg}$ and $\eta_g^o < 0.165$) cannot be economically utilized for electric power production in a purely geothermal plant. This limitation does not apply to the hybrid system. This is a very important advantage because it allows us to use the much more abundant low-grade geothermal sources for the production of electricity instead of using them for space heating. In the latter case, sources in the temperature range $60\text{-}150^{\circ}\text{C}$ would be wastefully misapplied.

Table I

Characteristics of the steam cycles

	Subcritical	Supercritical
Initial steam temperature	540	540 °C
Initial steam pressure	16.5	24.0 MPa
Number of reheat stages	1	2
Reheat temperature	540	540 °C
First reheat pressure	3.9	5.9 MPa
Second reheat pressure	—	2.0 MPa
Condenser pressure	5.5	5.5 kPa
Turbine isentropic efficiencies:		
High pressure	0.82	0.82
Intermediate pressure	0.86	0.86
Low pressure	0.82	0.85
Dryness fraction at exhaust	0.95	0.98
Number of feedwater heaters	7	7
Bleed pressures: P_1	3.9	5.9 MPa
P_2	1.92	3.5 MPa
P_3	0.99	2.0 MPa
P_4	0.45	0.86 MPa
P_5	0.21	0.40 MPa
P_6	0.08	0.17 MPa
P_7	0.035	0.066 MPa
Pressure loss in heat exchangers	10%	10%
Pump efficiency	0.8	0.8
Terminal temperature difference in feedwater heaters	2	2 °C
Final feedwater temperature	241	266 °C
Cycle efficiency	0.428	0.446

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Figure Captions

Figure 1 Typical geothermal energy conversion systems.

a - Flash system

b - Binary system

c - Total flow system.

Figure 2 Simple hybrid fossil-geothermal system.

Figure 3 Schematic representation of a hybrid system in contrast with a separate fossil system and a separate geothermal system.

Figure 4 Representation of the available work W^o and $\bar{W}^o$ on a T-s diagram.

Area oo'rbeo $\equiv W^o$

Area r'rber' $\equiv \bar{W}^o$

Figure 5 Variation of η_g^o and $\bar{\eta}_g^o$ with T_b ----- η_g^o _____ $\bar{\eta}_g^o$

Figure 6 Flow diagram of a modern steam power plant.

Figure 7 Limiting hybrid plant efficiency η_{lim} as a function of the geothermal heat fraction ϕ .

----- $T_b = 250^\circ\text{C}$

_____ $T_b = 200^\circ\text{C}$

----- $T_b = 150^\circ\text{C}$

Figure 8 The flow diagram of hybrid plant based on the steam plant of Figure 6.

Figure 9 Variation of η/η_f^* and ϕ with T_b

_____ supercritical cycle

----- subcritical cycle

Figure 10 Variation of η/η_f^* and m_g/m_g^* with ϕ

_____ supercritical cycle

----- subcritical cycle.

Figure 11 The economic figure of merit F_g for the subcritical hybrid system.

_____ $\eta_u = 0.7$

----- $\eta_u = 0.6$

Figure 12 The economic figure of merit F_g for the supercritical hybrid system.

_____ $\eta_u = 0.7$

----- $\eta_u = 0.6$

Figure 13 The geothermal figure of merit F_g .

_____ supercritical cycle

----- subcritical cycle.

Figure 14 Limiting values of the utilization efficiency of purely geothermal plants.

Figure 15 The work amplification factor.

Figure 16 Fossil fuel utilization factor F_f .

_____ supercritical cycle

- - - - - subcritical cycle.

(a) FLASH SYSTEM

(b) BINARY FLUID SYSTEM

(c) TOTAL FLOW SYSTEM

Fig. 1

Fig. 2

Fig. 3

Fig. 4

Fig. 5

Fig. 6

Fig. 7

Fig. 8

Fig. 9

Fig. 10

Fig. 12

Fig. 13

Fig. 14

Fig. 15

Fig. 16