AN EVALUATION OF GEOTHERMAL ENERGY POTENTIAL

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NOMENCLATURE

C_p	specific heat at constant pressure, Btu/lb., ^{o}F
D	diameter, ft.
f	Fanning's friction factor, dimensionless
F_r	frictional loss, ft.-lb./lb.
f(t)	transient time function, dimensionless
g	acceleration due to gravity, ft./sec.^{2}
g_c	conversion factor, 32.2 ft.-lb. mass/sec.^{2}, lb. force
H	enthalpy, Btu/lb.
h	film coefficient, Btu/hr. ft.^{2} ^{o}F
h_c	conductive and convective coefficient, Btu/hr. ft.^{2} ^{o}F
h_r	radiation coefficient, Btu/hr. ft.^{2} ^{o}F
J	mechanical equivalent of heat, 778 ft.-lb./Btu
K	thermal conductivity, Btu/hr. ft. ^{o}F
K_{ha}	thermal conductivity of fluid in the annulus, Btu/hr. ft. ^{o}F
K_{hc}	equivalent thermal conductivity of the annular fluid with natural convection effects, Btu/hr. ft. ^{o}F
m	water production rate, lb./hr.
N	number, dimensionless
p	pressure, psia

P_{CAP}	power plant capacity, MW
Q	heat added to the fluid, Btu/lb.
r	radius, ft.
T	temperature of water in the wellbore, ^{o}F
U	overall heat transfer coefficient, Btu/hr. ft.^{2} ^{o}F
v	velocity, ft. /hr.
W	water consumption rate, lb. /KWH
w_f	work added to the fluid, ft. -lb. /lb.
Z	depth, ft.
α	thermal diffusivity of earth, ft.^{2}/hr.
β	thermal volumetric expansion coefficient of the fluid in the annulus, $^{o}R^{-1}$
ϵ	emissivity, dimensionless
ρ	density, lb. /ft.^{3}
μ	viscosity, centipoise

Subscripts

an	annular
cas	casing
cem	cement
ci	casing inside
co	casing outside
e	earth
h	hole (cement-formation interface)

i	inside of flow string
ins	insulation
insi	inside of insulation
inso	outside of insulation
IW	injection well
PI	power plant inlet
PIPE	surface pipe
PW	producing well
T	total
ti	tubing inside
to	tubing outside
TOTAL	total

CHAPTER I

INTRODUCTION

Energy is essential to both the economic and social welfare of any nation. Especially in a developed country like the United States, lack of sufficient supply of energy can result in a worsening of economic and social problems which might ultimately lead to national chaos. One of the primary factors perhaps more responsible than any other for the United States' level of affluence has been an ample and relatively inexpensive supply of energy.

In 1970 total energy consumption in this country was equivalent to approximately 14.5 billion barrels of crude oil. The rate of growth in energy consumption in the U.S. has been doubling about every 15 years and even though the nation is currently in the grips of an "energy crisis," it is expected that most energy forecasts will support prior work in projecting this trend to continue at about the same growth rate into the forseeable future (1, 2). The domestic supply of energy resources required during the next 20-25 years to meet this demand, however, is not very adequate, especially if attention is restricted to conventional energy resources such as natural gas, petroleum, coal and nuclear energy.

Diminishing reserves of petroluem in the U.S. are of great concern. Even with an accelerated rate of discovery of domestic petroleum, it is quite likely that at least one-third of the liquid petroleum required will continue to have to be imported by the early 1980's (3). This, no doubt, will continue to aggravate the already serious problem brought about by an imbalance of payments. Also, the time of ample supply of natural gas in the U.S. appears to be over forever, even though a temporary improvement in the gas supply situation may occur if the wellhead prices of natural gas are allowed to increase substantially (4). In the light of the foregoing, it is apparent that the U.S. will never again be self-sufficient in petroleum resources.

The U.S., however, has a huge resource base of coal. Although its use may help alleviate the energy shortage problem, its impact will be less than that which in general is expected due to environmental restrictions on the quality of coal and its geographical location.

The installation of a sufficient supply of nuclear energy to meet the nation's needs is still a long way from being realized due to a combination of societal and technological difficulties. Even though electricity produced by nuclear plants will be increased by many times during the next quarter-century, not enough new plants are planned to make up for the expected shortage of fossil fuels (5).

Thus, a substantial shortage in the domestic supply of energy resources is likely to continue for some time into the very near future. Such a pessimistic view appears particularly realistic if immediate steps are not taken to encourage the development of alternative sources of energy in support of a growing U.S. energy economy.

A number of unconventional domestic sources of energy should be considered in an assessment for possible supplemental energy resources. These include geothermal energy and novelties such as solar, tidal and wind energy. However, of these, the prospects for economic exploitation of geothermal energy are considered by many to be the more likely. One of the main reasons supporting this consideration is the fact that geothermal energy is already being successfully exploited.

It is recognized in this work that geothermal energy offers a tremendous amount of potentially harnessable energy if "low grade"* reserves can be exploited for commercial use. Whether this event occurs or not will depend upon the cost required to exploit the "low grade" energy. Even though it is the relative cost and not the absolute cost of an energy resource that determines its selection, the former can only be obtained by comparison of the latter with the cost of other forms of energy. Accordingly, the purpose of this dissertation is to establish a base cost for exploiting "low grade" geothermal energy under various existing circumstances.

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*The use of the term "low grade" geothermal energy, for the purposes of this dissertation, is as given in the Scope of the Study in Chapter II.

Japan, Iceland, New Zealand, Mexico and the U.S. are now using geothermal steam for power production.

The first U.S. geothermal power plant was commissioned in 1960 on the Geyser's steam field in northern California. This is by far the largest steam field discovered in the world. The first plant was rated at 12.5 MW and according to the present expansion plans, the total capacity will reach in excess of 600 MW by 1980 (7).

In an effort to alleviate the current energy crisis, the U.S. government has shown a renewed interest in the development of the geothermal energy by passing the Geothermal Steam Act of 1970. This Act has established the development of U.S. geothermal resource as a national goal (8).

Potential of Geothermal Energy

As previously mentioned, the total heat flow from the interior of the earth is estimated to be over 950×10^{15} Btu/year. Even if it could be utilized at ten percent efficiency, this amounts to an energy equivalent of about 20.5 billion barrels of oil per year. This is more than the world's oil production during 1971. Furthermore, for all practical purposes, it is non-depletable. Although such enormous amounts of energy can only be made available in theory, the practical amount of energy that can be exploited depends upon the natural circumstances, available technology and associated economics.

At present the only geothermal energy that is being exploited commercially in the U.S. is located in areas where relatively high temperature gradients, in the order of $15^{o}F$ to $50^{o}F$ per 100 feet, exist. Undoubtedly, these are economically the most attractive reserves and their commercial feasibility has already been established (9). Unfortunately, however, such areas are very limited in number and cannot contribute significantly to the total U.S. energy market.

It has only recently been appreciated that tremendous reserves of geothermal energy exist in regions where relatively low temperature gradients exist. These areas are widespread and offer the advantage that the problem of long distance transportation or distribution of energy may be avoided. It is estimated that, in general, the ratio of these reserves to the reserves in the high temperature gradient areas is over 10,000:1 (10). Even if it is assumed that this estimate of reserves is overly optimistic, the amount of energy that must realistically be available is still fantastic. This nationwide availability is perhaps a unique characteristic of geothermal energy unlike any of our conventional energy sources. Obviously, if geothermal energy is ever to become a significant source of energy in the U.S., it is almost essential that these areas are exploited. The real question, therefore, in the case of "low grade" geothermal energy is not its availability but the cost this energy can be harnessed with present technology. This dissertation attempts to make an evaluation of the geothermal energy potential of such resources and, hence, the following pages should be viewed in that perspective.

Utilization of "Low Grade" Geothermal Energy

Presently, geothermal energy produced in the form of steam at The Geysers in California is the only geothermal energy in the United States being utilized for power generation. There are a number of other opportunities, such as space heating, desalination and mineral extraction, for which geothermal energy may also be used. These uses have been put into practice in some foreign countries and are mentioned here as a possibility in this country, especially in "low grade" energy exploitation. Even though these non-power uses offer a great potential application for geothermal energy, it appears that initial consideration should be given to its conversion into power. This direction is believed to be justified by the fact that the demand for electricity is increasing at a much faster rate than is the demand for other types of energy. This situation is not expected to change in the near future. Hence, the effort to search for energy resources that can be economically converted to electricity is certain to increase. Accordingly, this study will limit itself to the utilization of "low grade" geothermal energy in power generation.

CHAPTER II

ORGANIZATION

Objective of the Study

The first and primal objective of this study is to assess the cost of power generated by using "low grade" geothermal energy existing under a variety of naturally occurring conditions.

The cost of geothermal power is, obviously, dependent upon the technology employed in bringing geothermal energy to the surface and converting it to electricity. Hence, a secondary objective of this study is to assess the presently available technology in these areas and, especially, investigate some of the technical options as to their effect on the cost of geothermal power. It is a further objective to study the variations in the cost of geothermal power as a function of different economic circumstances.

Scope of the Study

"Low grade" geothermal energy, as defined for this study, is the geothermal energy available in the areas where the temperature gradient is between 2°F and 5°F per 100 feet of depth. This arbitrary classification is chosen as it appears to represent areas quite widely spread over the nation which are not presently considered as potential areas for recovery of geothermal energy. Also, this range of temperature gradients is substantially lower than exists in those areas where geothermal energy is presently being harnessed.

In order to avoid repeated usage of the phrase "low grade" in referring to the quality of geothermal energy available, the subsequent use of the term geothermal energy will refer to the "low grade" type unless otherwise specified.

It is recognized that the cost of geothermal power will depend upon the choice of variables associated with the subsurface and surface design of the production system, construction and operation of the power plant, and the economic model used in the cost analysis. In this study, primary attention is focused on evaluating the effect of various subsurface designs on the cost of power. However, for the sake of completeness, the effects of some variables related to the design of the surface gathering facility and the power plant are also considered.

Besides the technological variables mentioned above, the natural conditions existing in an area also affect the cost of power. In this case, of the many possible variables representing the natural surroundings, the temperature gradient, pressure gradient, reservoir rock flow characteristics and individual well productivity have been selected for an evaluation of their effect on the cost of producing geothermal power.

In addition to data depicting the system design, economic model and natural surroundings, many other supporting data were also used in making calculations of the cost of power. These data usually involve the cost of labor and materials which certainly would vary with time and geographic location as well as with the nature of the item itself. In keeping with the systems' approach, the calculations made in this study are based mainly on one set of supporting data which is thought to most accurately represent present circumstances. This necessarily fixes the time frame of this study. There is no doubt that supporting data, such as that related to geothermal power development expenditures, will vary in the future and, hence, will have a direct bearing on the cost of power. Since it is beyond the scope of this study to project the cost of the various supplemental data sources into the future, the cost of power from geothermal sources can only be evaluated relative to current alternatives. It is expected that changes in costs in the future will be proportioned so that the relative cost for producing power from the different energy resources will remain about the same.

Format of the Study

The purpose of this study is to arrive at the cost of producing geothermal power as a function of a number of variables related to production system design, power plant design and the naturally occurring conditions. In order to accomplish this goal in a systematic manner the study has been divided into three major parts. In the first part, a mathematical model describing a geothermal energy production and conversion system is developed whereas in the second part an economic model capable of assessing the technological system is described. The final part involves a combination of these two models to arrive at the cost of producing geothermal power under various assumed conditions. Each part has been divided into a number of sub-parts to deal with individual aspects of geothermal power development. Peripheral subjects such as the exploration of a geothermal field, injection system design, etc. are also discussed for continuity.

CHAPTER III

DEVELOPMENT OF THE GEOTHERMAL POWER SYSTEM MODEL

Areas that are considered as potential sources of geothermal energy in this study are mainly sedimentary basins where the geothermal gradients are between $2^{\circ}F$ and $5^{\circ}F$ per 100 feet of depth. Geothermal energy, in such areas, is stored in the form of hot liquid water which must be produced and transported to the power plant where the heat energy in the water is converted to electricity. Waste water from the power plant outlet should be then disposed of in an environmentally acceptable manner and possibly in a way that would assure a continuous supply of water to the geothermal reservoir. Thus, the geothermal power system, briefly described above, is comprised of four different components, namely

1. geothermal reservoir,
2. energy production and transportation system,
3. power plant, and
4. water disposal system.

In this chapter, first, these components are discussed to understand and more clearly define the total system. Then a mathematical model is developed which will provide a foundation for assessing the cost of geothermal power.

Development of the Physical Model

Geothermal Reservoir

Heat from the interior of the earth continuously flows toward its surface and this is generally considered as the source of all geothermal energy. In areas where sedimentary rocks are present, heat is transferred by conduction through the solid phase and by convection of the water within the rocks. The water being mobile may be caused to flow to the surface and utilized in electricity production. Thus, the availability of water at an elevated temperature is the main prerequisite of a geothermal reservoir. Under natural conditions, heat energy is supplied to the reservoir via the heat flow mentioned above at a constant heat flux rate. Similarly, the supply of water in and to the reservoir is controlled by the geological and hydrological characteristics of the area. In addition, the hot water in a geothermal reservoir is normally pressurized due to the weight of the column of water above it and may even exist at a higher or geo-pressure. The geothermal reservoir, therefore, may be visualized as a hot bed of porous rocks saturated with pressurized water at equilibrium temperature. Power available from such a reservoir depends upon the temperature of water and the rate at which water can be obtained from the reservoir. At this stage, therefore, there are three main characteristics that describe a geothermal reservoir, namely

1. reservoir temperature
2. reservoir pressure
3. flow capacity.

These three characteristics may also vary with time, once a reservoir is tapped for energy production. This variance, however, is not essential but instead depends upon the method of exploitation. For example, the temperature of the reservoir may decrease if the rate of water withdrawal exceeds natural refill rates. Similarly, reservoir pressure may also decrease. Thus, under certain production conditions a time variance could occur. By the same token, however, it would seem possible to reduce or completely eliminate time variance in reservoir temperature and pressure by adjusting water withdrawal and supply rates. The power generated by a geothermal system will also be a direct function of the flow rate of water and, hence, it is most desirable to attain the highest rate of withdrawal that eliminates temperature and pressure deterioration of the reservoir. In addition to pressure, the flow rate of water from the reservoir depends upon the permeability, rock flow characteristics, reservoir size and the properties of the water itself.

Production and Transportation System

A second component in the geothermal power system is the water production and transportation system. The function of this component is to carry energy, with minimum feasible losses, from the reservoir to the energy conversion device, namely, the power plant. The loss of energy in the production and transportation system in general occurs by the reduction in temperature caused by the loss of heat to the surroundings. Water in the reservoir and in the production piping may exist in either the liquid or vapor phase, or both, depending upon the existing pressure and temperature. In the production system, these conditions are controlled through selection of the design variables such as the well completion technique, diameter of the flow strings, diameter of the surface pipe, etc.

Power Plant

The third component of the geothermal power system is the power plant. Electricity is generated in the power plant by extracting heat from the water produced from the geothermal reservoir and converting this energy into electricity. With present technology, hot water may be utilized for power production in three different ways: using hot water as feed water in a conventional steam power plant, flashing hot water to steam for expansion through a turbine, and using hot water to vaporize a secondary fluid which in turn drives a turbine.

Use as Make-Up Water. Electric power may be produced by using hot water directly as feed water in a conventional steam boiler. Steam produced from such a system may be exhausted through a turbine for power production.

The principal advantage of this method is that it conserves that portion of the fuel normally burned in raising the temperature of water from the condenser temperature to the temperature of the incoming geothermal fluid. This may allow a decrease in the size of a boiler needed and thus affect the cost.

This method, however, has a number of disadvantages. Perhaps the most important one is that the geothermal water must be treated for removing solids, dissolved salts and other possible corrosive materials before it can be used in a boiler. Even with an efficient system for treatment, cost of maintenance of boiler tubes and turbine blades is likely to be considerably high. This procedure for using geothermal water to conserve boiler fuel also requires an independent water production system. The savings in fuel cost must pay for all production facilities and the added maintenance costs. It, therefore, appears that this method is not too practical unless fuel costs become extremely high.

Flashing to Steam. A second way of using geothermal water in power production is to flash it to a saturated low pressure steam which can then be used to drive a turbine.

The primary advantage of this method is that it eliminates the need for a boiler and also for any fuel usage by the power plant.

Even though at first glance this method appears to be a most logical and simple way to produce power from geothermal water, it presents a number of disadvantages (11):

1. It is thermodynamically inefficient because much of the energy is lost in raising the water in the well and in the flashing to steam;

2. Steam so obtained will be at a much lower temperature and pressure than the original temperature of water;

3. Low pressure steam turbines are very costly per kilowatt of generating capacity because the specific volume of steam is high;

4. Thermal efficiency is low because high condensing temperatures must be used. Turbines become overly expensive at low condensing temperatures;

5. Steam is wet at the turbine inlet and becomes more wet as it passes through the turbine. This increases blade maintenance problems;

6. When steam flashes, dissolved gases are also released. To fit in with the environment, these gases must be disposed of in a manner that will not pollute the atmosphere;

7. When dissolved gases are released, the chemical composition of the water changes. Usually this results in the precipitation of salts as scale on the walls of the well. This can completely plug up the well in a short time;

8. Pipes between the well and the power plant must be larger to carry steam than to carry a equivalent amount of hot water energy;

9. Because of a relatively low thermal efficiency, more wells

must be drilled per unit of power produced than would be the case for a more efficient plant.

Use of a Secondary Fluid. A third method uses geothermal hot water to vaporize a low boiling secondary fluid which then drives the turbine in the power plant (12). The vapor of the secondary fluid at high pressure is expanded through a turbine and condensed in an air- or water-cooled condenser. The condensate is pumped back to the heater and boiler to repeat the cycle. The cycle is shown in schematic form in Figure 1.

A power plant that uses a binary fluid system such as just described has a number of advantages over the flashing steam approach. Some of these are (13):

1. Maintaining the water under pressure prevents the escape of gases and salt precipitation, thus reducing if not completely eliminating the problem of production well plugging;

2. The temperature of the geothermal water at the heat-exchanger inlet can be maintained at a much higher value than is the case when steam is flashed before reaching the power plant inlet;

3. A gas removal system is not required;

4. Since oxygen cannot enter the system, one of the potential causes of corrosion is thus eliminated;

5. Water pipes from the well to the power plant are smaller in diameter than steam pipes would be in a flashing plant design. This reduces the cost of the gathering system.

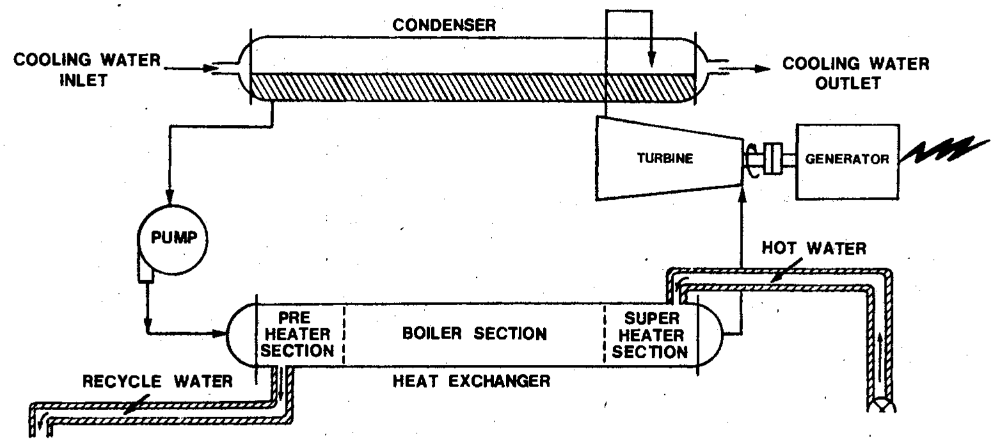

Figure 1. A Schematic Diagram of a "Magmamax" Power Cycle

6. The thermal efficiency of the pressurized water power plant is higher than the flashed steam plant. This reduces the number of geothermal wells required for a given size power plant.

This method, of course, eliminates the need for a boiler and hence there is no need for any fuel. However, water must be lifted by a submergible deep well pump, which adds to the cost of the project. Also, it requires a heat-exchanger and an initial charge of a secondary fluid. These items would incur additional investment.

The comparison of the three methods discussed above seems to favor, at least technically, a binary fluid system for power generation and hence it is chosen here. This type of power plant is characterized primarily by the choice of the secondary fluid and by the flow rate of water required to generate a given amount of power.

Water Disposal System

A fourth and final component of the geothermal power system is the water disposal problem. The effluent from the power plant, in general, is useless in terms of energy content and must be disposed of in an environmentally acceptable manner. Basically, three types of pollution problems may arise in water disposal:

1. Thermal pollution may occur if the waste water is disposed of in neighboring lakes, rivers or streams.

2. Air pollution may occur if the dissolved gases from the water are allowed to escape into the atmosphere.

3. Mineral crustacians are possible if water is dumped on the surrounding ground.

Thus, it can be seen that various pollution problems may occur if waste water is disposed of as surface runoff. Therefore, it seems prudent to avoid them by disposing the water underground, especially at a depth which is below the fresh water level in an area. Furthermore, this may enhance the recharge of the reservoir which is desirable to assure a steady supply of geothermal energy. Direct recharge into the aquifer could prolong the life of a reservoir almost indefinitely. Thus, it appears desirable to reinject the water back into the ground so as to not only decrease pollution but also to increase the life of a geothermal reservoir.

Waste water injection is carried out by first drilling a number of injection wells around the power plant. The number of injection wells and their relative distribution depends upon many factors, such as the amount of water to be injected, geological and hydrological conditions in the area, etc. The injection system may be characterized by the number and distribution of injection wells used in the system.

The four components discussed above complete the basic elements of a geothermal power system. A power plant utilizing hot water for its energy source is depicted in Figure 1. A geothermal power system showing the general design of production and injection wells and linking the power plant to the geothermal reservoir is presented in Figure 2.

The physical system which is being modeled consists of an

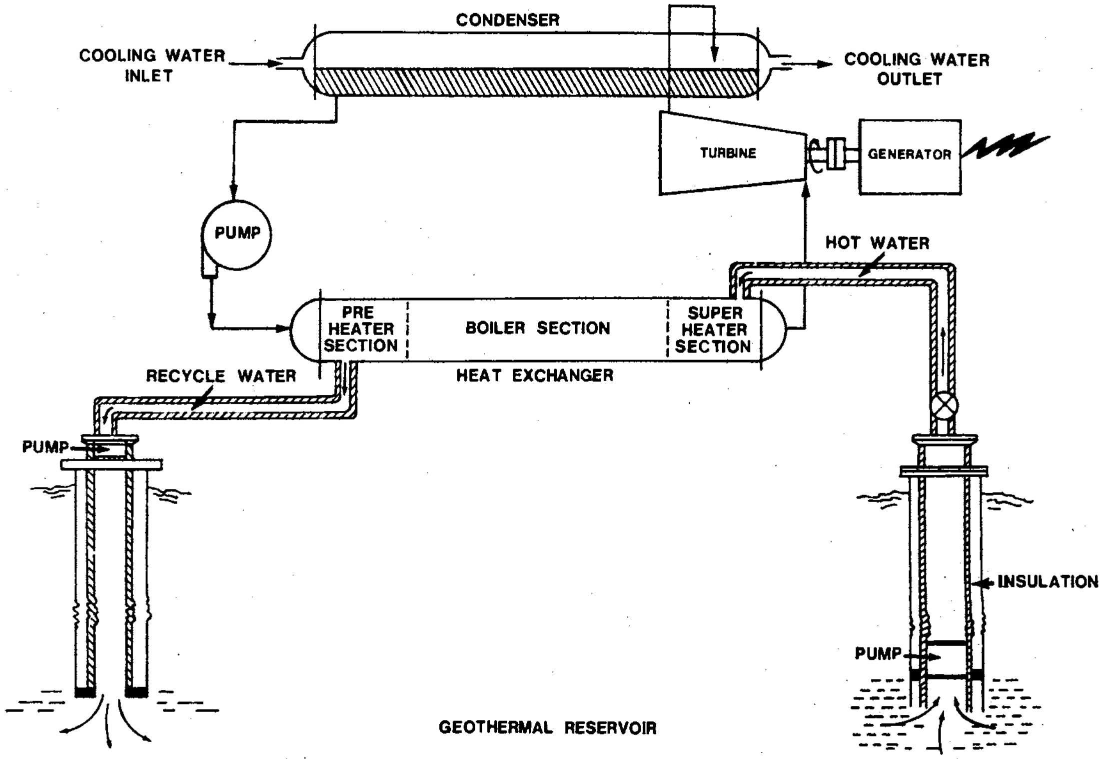

Figure 2. A Schematic Diagram of Geothermal Power System

integration of the four components discussed above. For each component, there are certain characterizing factors that have been selected as representative of those due major design consideration. To begin with, the source of energy, the geothermal reservoir, is characterized by its pressure, temperature and reservoir rock flow characteristics. The production and transportation system is characterized by its design, especially as it affects the loss of temperature and pressure of water in the production system. The power plant is distinguished by the nature of its secondary fluid and the flow rate of the hot water required to maintain a specified power output. As mentioned, the waste water disposal system has two general characteristics, namely the number of injection wells and their distribution.

Development of the Mathematical Model

There are a number of ways in which the mathematical model could have been developed. If it was decided to follow the path of the water as it flows through the complete system, one could start in the reservoir and proceed through the production and transportation system, power plant and finally through the injection system. However, a different approach has been taken here. In developing the mathematical model, it was expedient to analyze the system by letting the power plant assume a central role. Then the size and type of the power plant required will establish the flow rate of water necessary to generate power at full capacity.

For a power plant using secondary fluid for power generation, the important design considerations are:

1. choice of the secondary fluid,
2. size of the plant, and
3. temperature and flow rate of water required at the power plant inlet.

Inasmuch as there are several secondary fluids which may be used for a given temperature range of water, the fluid selected must satisfy, as much as possible, the following requirements. This list of desirable qualities for a secondary fluid is by no means exhaustive but it represents the more important ones that should be considered for low-cost operation of the power plant.

1. It should have a reasonably high vapor density at turbine operating conditions. This helps to reduce the size and cost of the turbine.

2. The vapor pressure of the secondary fluid should be above atmospheric pressure at all operating conditions. This eliminates the possibility for air leakage into the system and reduces the severity of corrosion and maintenance problems.

3. The critical temperature of the secondary fluid should be high enough to permit vaporization under pressure within the range of the hot water temperature available to the boiler. This helps to reduce the heat-exchanger area required.

4. The secondary fluid should be non-corrosive in nature,

thus allowing the use of low cost materials in constructing the power plant.

5. The thermal characteristics of the secondary fluid should enhance heat flow as much as possible. Especially, good thermal conductivity is desirable.

6. The molecular weight of the secondary fluid should be reasonably high. In general, this improves turbine efficiency, reduces its size, reduces turbine stress and vibration problems, helps to reduce maximum coupling torque caused by generator overloads and tends to reduce cavitation damage in the boiler feed pumps.

7. The fluid chosen should be relatively low cost.

8. The fluid chosen should be non-toxic.

The range of hot water temperature at the power plant inlet chosen for this study is between 325°F and 450°F. There are several reasons why this particular choice is thought to be appropriate.

1. The temperature of 450°F is near the maximum temperature at which submergible pumps can operate.

2. Temperature gradients considered for this study vary from 2°F per 100 feet to 5°F per 100 feet. For the lowest temperature gradient of 2°F per 100 feet, a reservoir drilling depth of approximately 15,000 feet is necessary to meet the lower temperature requirement of 325°F and a well approximately 20,000 to 22,000 feet deep is necessary for the 450°F temperature limit. This depth is within the realm of present technology. It is assumed that the average

surface temperature is 75°F.

3. Assuming the power plant condenser operates at 80°F, the maximum conversion efficiency that can be obtained, even at the lowest water temperature, is about 30 percent. This appears to be sufficiently high to justify further economic consideration.

4. Hot water, even at the higher temperature of 450°F, will flash to steam at less than 20 percent quality. This steam can be converted to electricity only at 5 to 7 percent efficiency. The 325-450°F temperature range selected appears to be consistant with the nature of the secondary fluids available to geothermal power systems.

5. The temperature range of 325°F to 450°F is sufficient to allow a broad selection for a secondary fluid which meets most of the desired qualities outlined above.

6. Most of the equipment such as tubing, casing, pipes, etc., needed for geothermal well completion will withstand the above temperature range.

Having selected the range of hot water temperature at the heat-exchanger inlet, a secondary fluid can now be selected which meets the maximum number of desirable qualities mentioned earlier. Of several fluids worthy of consideration ranging from Freon-12 to heavy hydrocarbons, Isobutane appears to more closely meet the requirements for the selected temperature range (13). It has a relatively high molecular weight and density; its vapor pressure is well above atmospheric pressure at temperatures more than 60°F; and it is non-corrosive, non-toxic as well as being relatively inexpensive. Isobutane has a high enough critical temperature, a good thermal conductivity and other desirable thermal characteristics. Flammability is a major disadvantage in the selection of Isobutane, but this would be the case also for practically any hydrocarbon worthy of consideration. Fortunately, hydrocarbon handling technology is well advanced so that the danger of using a flammable secondary fuel is believed to be minimal, and would certainly be no more hazardous than is a gas-fired power plant of any conventional type.

In addition to choosing a secondary fluid, a choice must also be made of the turbine inlet and outlet conditions. It is desirable to choose these conditions so that the turbine operates throughout a superheated region of the fluid as this tends to help reduce corrosion of the turbine blades. In making a choice of pressure and temperature conditions, consideration must also be given to the conversion efficiency. Higher turbine inlet temperatures and lower outlet temperatures increase the conversion efficiency. However, they are respectively limited by the temperature of the geothermal water available at the heat exchanger inlet and the temperature of coolant used in the condenser. Assuming that the geothermal water is available at 325°F or higher and the condenser is maintained at 80°F, by using water as a coolant, the recommended turbine inlet conditions of Isobutane are 290°F and 500 psia (14). The corresponding condenser conditions are 80°F and 50 psia.

The selection of the Isobutane conditions at the turbine inlet and outlet, the temperature of geothermal water and the size of the power plant fix the water consumption rate at the plant. For a power plant with the above mentioned turbine inlet and outlet conditions of Isobutane, the hot water requirements in pounds per kilowatt hour, as a function of water temperature, have been calculated by Anderson et al. and are presented in Figure 3 (14). It is assumed in these calculations that the minimum temperature difference between hot water and Isobutane in the heat exchanger is fixed at 15°F. Accordingly, a break in the water consumption curve in Figure 3 occurs approximately where the minimum temperature difference occurs at both boiling and condensing temperatures. At hot water temperatures below 350°F, the minimum temperature difference occurs at boiling while at higher temperatures it occurs at the condensing temperature. Approximate temperature profiles of Isobutane and water in counterflow are shown in Figure 4 (14).

As would be expected, the availability of hotter geothermal water reduces the necessary water consumption rate at the power plant. For example, as shown in Figure 4, if water is available at 325°F at the superheater inlet, it could leave the preheater at 179°F. In this case the minimum temperature difference is seen to occur at the boiling point of Isobutane. Each pound of water gives up 148 Btu to heat Isobutane. It requires 208 Btu to heat each pound of Isobutane from the condenser conditions to the turbine inlet conditions. Thus, 1.4

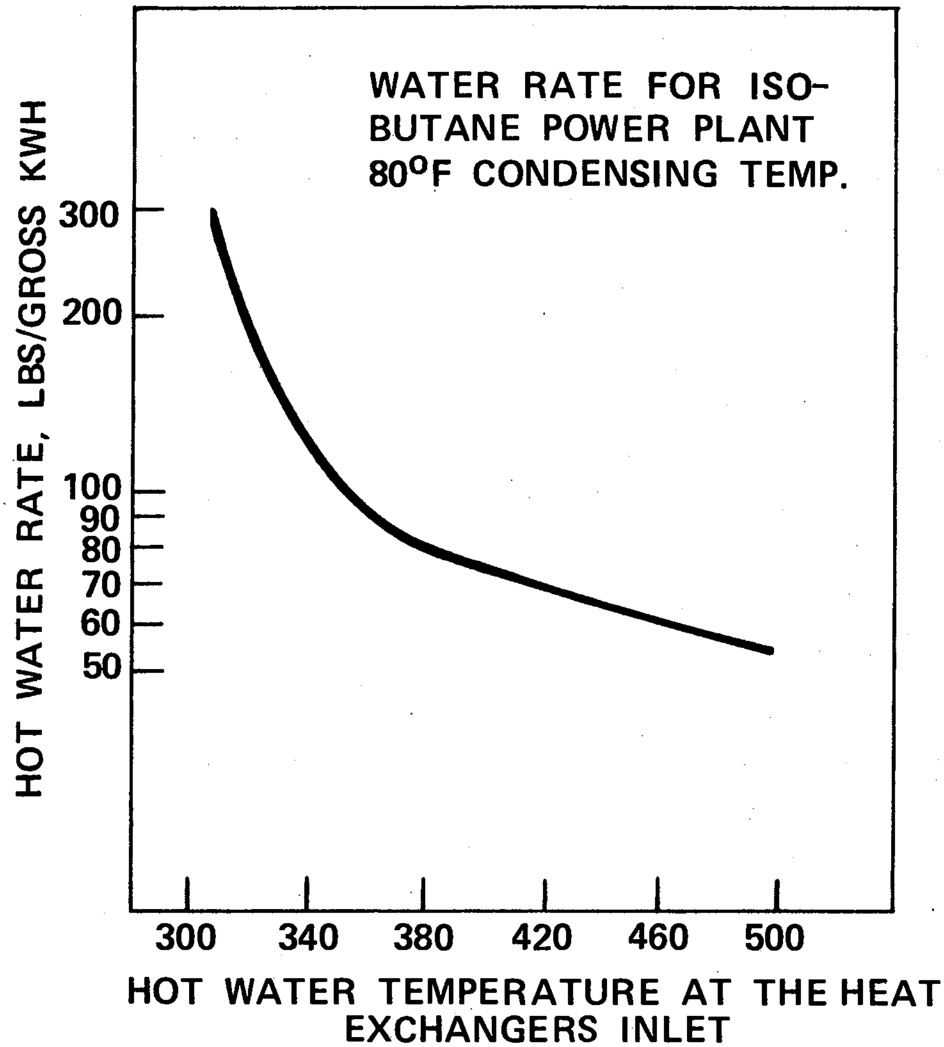

Figure 3. Water Requirements for Isobutane Power Plant

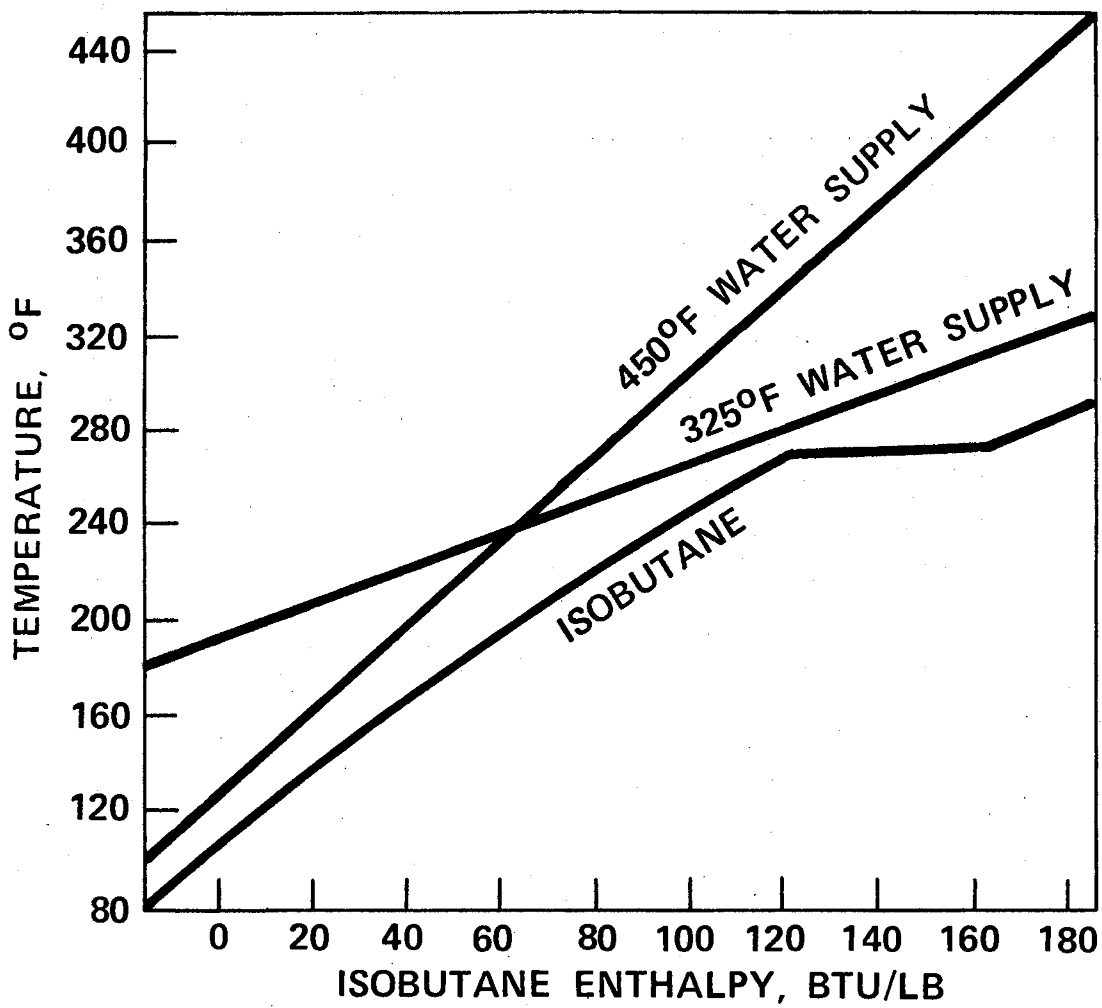

Figure 4. Water and Isobutane Temperatures In and Out of Countercurrent Heat-Exchangers Used in This Study

pounds of water are required per pound of Isobutane. These conditions, referring again to Figure 3, show water consumption as 165 pounds per gross KWH.

The other case shown in Figure 3 is for a 450°F water supply. In this case, the water comes in at 450°F and goes out at 96°F, giving up 360 Btu per pound of water. To heat one pound of Isobutane through the cycle requires only 0.58 pounds of water or, only 64 pounds of water are consumed per KWH. The minimum temperature difference occurs, in this case, at the Isobutane condensing temperature.

Thus, in general, the water requirements at the power plant of a given size are a function of the water temperature at the power plant inlet. Now, let T_{PI} be the temperature of water in °F at the power plant inlet and also let W be the corresponding water consumption rate in pounds per gross KWH. Then, the total flow rate of water, W_{TOTAL}, in pounds per hour required at the plant is given by Equation (1):

$$W_{TOTAL} = 1000 \times P_{CAP} \times F_{LOAD} \times W \qquad (1)$$

where

P_{CAP} = power plant capacity, MW and

F_{LOAD} = load factor, dimensionless.

Water requirements at the power plant are met by the water produced from the geothermal wells. The number of production wells required to support a plant depends upon the average productivity of each well. While it may be possible, under certain circumstances for well productivity to vary with time, this study has assumed it to be constant throughout the life of the geothermal power plant. Now, if m is the average productivity per well, in pounds per hour, then the total number of production wells required to support the power plant are given by:

$$N_{PW} = W_{TOTAL} \times \frac{1}{m} \tag{2}$$

Water from each production well is transported to the power plant for power generation and the waste water is injected into the reservoir via injection wells. The number of injection wells required in a particular situation depends mainly upon the desired rate of water injection and hence, indirectly, it depends upon the water production rate. Since the water production rate is a function of the number of production wells, the total number of injection wells required can also be expressed as a function of the number of production wells. Therefore,

$$N_{IW} = K \times N_{PW} \tag{3}$$

where

N_{IW} = number of injection wells required and

K = proportionality constant.

The total number of injection and production wells may be expressed as:

$$N_T = N_{PW} + N_{IW}$$

or

$$N_T = N_{PW} + K \times N_{PW}. \tag{4}$$

The total land required for development of the geothermal power system is made up of three catagories:

1. land for drilling production wells,

2. land for drilling injection wells, and

3. land for power plant and other necessary facilities.

The land required for the first two catagories depends upon the well spacing. Well spacing is the area assigned to each production or injection well. If S_W is the well spacing, in acres per well, then the total land, in acres, for drilling of injection and production wells is given by:

$$L_{TOTAL} = N_T \times S_W. \tag{5}$$

In general, the land required for the power plant and other facilities is considerably smaller than the total land required for the drilling of production and injection wells and hence, it can be ignored for all practical purposes. It is assumed that each production and injection well is directly connected to the power plant. The length of an individual pipeline connecting a well to the power plant depends upon the distribution of wells and the total land developed. If it is assumed that the total area developed can be approximated by a square, with the power plant at the center, and that this square is divided into a number of smaller squares with each well, production and injection, at the center of the smaller square, then the length of the pipeline may be approximated by the following equation (15):

$$D_{LP} = \sqrt{L_{TOTAL} \times 43560/6} \qquad (6)$$

where

D_{LP} = length of pipeline in feet.

The water consumption at the power plant is mainly a function of water temperature at the plant inlet. When water is transported from the wellhead to the power plant, it loses some of its heat to the surroundings and thus, the water temperature required at the wellhead is higher. The temperature at the wellhead may be calculated by simultaneously applying two energy balances, namely the total energy balance and the momentum balance, between a point at the wellhead and a point just before the heat-exchanger.

The total energy balance is expressed as:

$$dQ - \frac{dw_f}{J} = dH + \frac{g}{g_c J}\, dz + \frac{vdv}{Jg_c} \qquad (7)$$

For incompressible fluid such as water, the enthalpy term may be expressed as:

$$dH = C_p dT + \frac{1}{J}\frac{dP}{\rho} \qquad (8)$$

Since water is flowing under steady state and there is no work done on or by water, $vdv = 0$ and $dw_f = 0$. Also, it is assumed that there is no change in the elevation of the pipeline and hence, $dz = 0$. Then, substituting for dH in Equation (7) from Equation (8), the following equation is obtained:

$$dQ = C_p dT + \frac{1}{J} \frac{dP}{\rho} \tag{9}$$

In order to reduce the heat loss, the pipeline is assumed to be insulated. Water in the pipeline is at a much higher temperature than the ambient, and it is assumed to be flowing under steady state. While ambient temperature varies seasonably, an average value for it may be assumed for simplicity. Under these conditions, heat loss to the surroundings may be calculated as:

$$dQ = - \frac{2\pi K_{ins} (T - T_{amb}) dD_{LP}}{\ln\left(\frac{r_{ins}}{r_{pipe}}\right) m} . \tag{10}$$

Substituting the value of dQ from the above equation into Equation (9) and then separating the terms gives:

$$\frac{dT}{dL} + \frac{2\pi K_{ins}}{C_p \ln\left(\frac{r_{ins}}{r_{pipe}}\right) m} T = \frac{2\pi K_{ins}}{C_p \ln\left(\frac{r_{ins}}{r_{pipe}}\right)} T_{amb} - \frac{1}{C_p J \rho} \frac{dP}{dD_{LP}} . \tag{11}$$

Now, the momentum balance equation is expressed as:

$$\frac{g}{g_c} dz + \frac{vdv}{g_c} + \frac{dP}{\rho} + dF_r + dw_f = 0 \tag{12}$$

However, for the steady state conditions with no pump work, $dz = 0$, $dv = 0$ and $dw_f = 0$. If Fanning's equation is used for the friction loss term, dF_r, then:

$$dP = - \frac{2 \rho f v^2}{g_c d_{pipe}} dD_{LP} . \tag{13}$$

Substituting for dP in Equation (11) from the above equation and solving for the hot water temperature at the wellhead gives:

$$T_{WH} = \frac{B}{A} + (T_{PI} - \frac{B}{A}) e^{AD_{LP}} \tag{14}$$

where

T_{WH} = wellhead water temperature, $^{\circ}F$

$$A = \frac{2 \pi K_{ins}}{C_p \ln \left(\frac{r_{ins}}{r_{pipe}} \right) m}$$

$$B = A \times T_{amb} - \frac{2 f v^2}{g_c d_{pipe} J C_p}$$ and

D_{LP} = length of pipeline, feet.

As mentioned earlier, T_{PI} is the water temperature, in $^{\circ}F$, at the power plant inlet. It may be observed from Equation (14) that the required water temperature at the wellhead is a function of the length of the pipeline, its diameter, thickness and thermal conductivity of insulation and water flow rate. For a chosen water temperature, T_{PI}, at the plant inlet, the required temperature at the wellhead, T_{WH}, may be calculated from Equation (14).

Now, a subsurface system to produce geothermal waters will be developed to satisfy the water temperature requirements at the wellhead. The subsurface system consists of a production well and the wellbore equipment such as tubing, casing and a pump to lift water from the bottom of the well to the power plant.

Obviously, the water temperature at the wellhead will be equal to the temperature of water at the bottom of the well minus any temperature reduction due to heat loss from the wellbore. The temperature at the bottom depends upon the drilling depth and the prevailing temperature gradient. The wellbore heat loss is a function of a number of variables associated with the subsurface system. The most obvious one that would affect the wellbore heat loss is the completion design. A geothermal well may be completed in two different ways:

Annular Completion

This is shown schematically in Figure 5. Two wellbore strings are used in this completion. Water flows through the inner tubing string, while the outer casing string is cemented to the formation. The annular area between the tubing and the casing may be filled with air or insulation or both. A submergible pump may be necessary to lift the water.

Non-Annular Completion

This type of completion, as the name suggests, does not have an annular area. Thus, it has only one string, the casing, in the wellbore. Water, therefore, flows through the casing. In this case also, water may need to be pumped by a submergible pump.

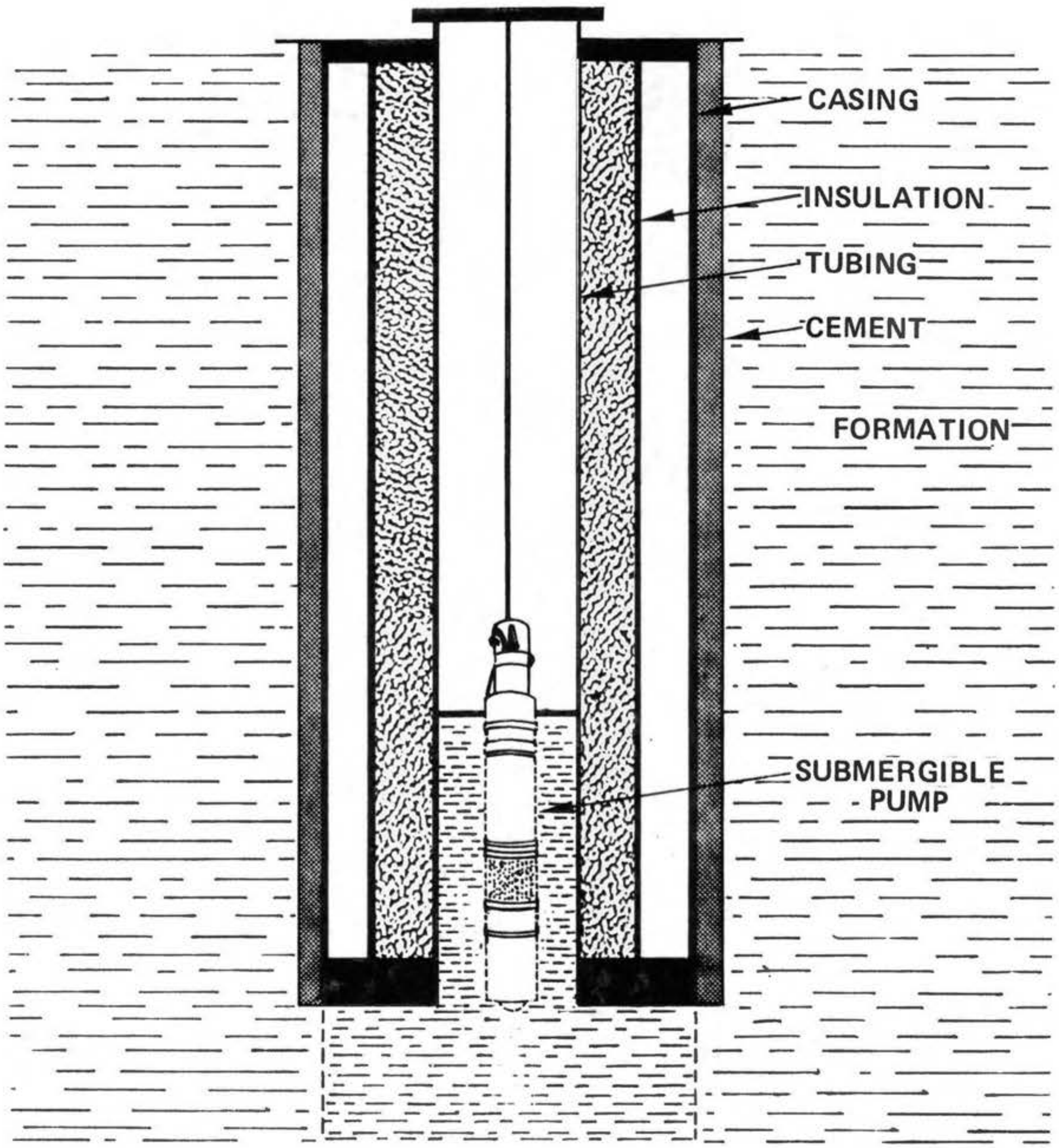

Figure 5. A Schematic Diagram of an Annular Wellbore Completion with Insulation

In order to quantify other variables that affect wellbore heat loss and to determine the water temperature at the wellhead, a mathematical model of the wellbore heat transfer will next be developed.

Several papers have been published, mostly in the petroleum industry, wherein the wellbore heat loss in steam injection was studied (16, 17, 18, 19, 20, 21). Specifically, the temperatures of the casing and tubing in the steam injection operations have been estimated and the short-term wellbore heat losses have been calculated. Most recently, the subject of thermal behavior of flowing wells has been of interest, especially due to the petroleum development in the permafrost areas of the North Slope.

The calculation of heat loss from a wellbore through which continuous production of liquid hot water is carried on could not be ascertained in the published literature. This kind of operation is different from steam injection in that there is no phase change involved in the wellbore. Also, most previous studies ignore the heat generated by friction. Geothermal hot water production, as defined in this study, involves a single phase, one-component continuous pumping system unlike any studied earlier by other authors.

In solving the problem, a general solution is first derived for an annular completion and then it is modified for a non-annular completion. The following assumptions are made in developing the heat transfer model:

1. The diameter of the flow string, casing, tubing or both,

as the case may be, insulation and the hole are constant through the entire wellbore depth.

2. The wellbore is vertical and the water flows under steady state condition.

3. Thermal properties of the formation and all the materials used in the wellbore equipment are constant with temperature and depth.

4. The geothermal gradient can be expressed by the linear approximation.

5. Heat transfer within the wellbore and in the formation is radial.

6. Heat transfer in and around the wellbore, up to the cement-formation interface, is rapid compared to the heat flow in the formation and, hence, it can be approximated very closely by a steady state solution.

7. Heat transfer into the formation is controlled by an unsteady state radial heat flow situation.

8. The unsteady state radial heat flow into the formation can be simulated by the solution for the case of a cylinder losing heat at a constant temperature or at a constant heat flux.

Water from the reservoir flows to the bottom of the wellbore and a submergible pump is installed right at the bottom. Water is pumped to the surface through a constant diameter tubing in the case of annular completion or through a constant diameter casing in the non-annular completion. For a wellbore such as this one, the hot water temperature is a function of depth as well as time. Initially, the heat loss would be much greater but it reduces as the temperature of the surrounding formation increases with time.

In order to completely describe the fluid at any depth in the wellbore, two energy balances, namely the total energy balance and the momentum balance are solved simultaneously.

The total energy balance is expressed as:

$$dQ - \frac{dw_f}{J} = dH + \frac{g}{g_c J} dz + \frac{vdv}{Jg_c} . \tag{15}$$

For incompressible fluid such as liquid water:

$$dH = C_p dT + \frac{1}{J} \frac{dP}{\rho_w} . \tag{16}$$

The hot water is flowing under steady state, and the energy balances are applied between the initial point just at the outlet of the pump and the wellhead. Therefore, $dw_f = 0$ and $vdv = 0$. By substituting for dH from Equation (16) into Equation (15) and dividing each term by dz gives:

$$\frac{dT}{dz} = \frac{dQ}{dz} - \frac{1}{J\rho_w} \frac{dP}{dz} - \frac{g}{g_c J} . \tag{17}$$

Now, the application of momentum balance to the system is expressed as:

$$\frac{g}{g_c} dz + \frac{vdv}{g_c} + \frac{dP}{\rho_w} + dF_r + dw_f = 0 . \tag{18}$$

Substituting Fanning's equation for the frictional loss, dF_r, in the above equation and dividing by dz yields:

$$\frac{dP}{dz} = -\rho_w \left(\frac{g}{g_c} + \frac{2fv^2}{g_c d_i} \right) . \qquad (19)$$

Equation (19) is now substituted in Equation (17). This step then gives Equation (20) as:

$$\frac{dT}{dz} = \frac{\frac{dQ}{dz} - \frac{2fv^2}{Jg_c d_i}}{c_p} \qquad (20)$$

The rate of heat transmission per unit depth, dQ/dz, in the above equation is given by (15):

$$\frac{dQ}{dz} = \frac{2\pi K_e (T_h - T_e)}{f(t)\, m} \qquad (21)$$

where f(t) is a time function as proposed by Ramey (17). It is used here for heat conduction between the cement-formation interface and the reservoir formation. Heat lost by the wellbore fluid to the surroundings passes through the cement and then is dispersed through the formation. If the main interest is to calculate heat loss over a long period, in months or years as in this case, then it can be assumed that the heat transfer in the wellbore, i. e. through the tubing, insulation, casing and cement, is steady-state while heat transfer to the earth from the cement-formation interface is unsteady radial transmission. Therefore, the evaluation of the time function f(t), which represents the unsteady heat flow to the earth, may be made from solutions for radial heat conduction from an infinitely long cylinder.

Three solutions are available for time functions f(t): 1) for a cylinder losing heat at constant temperature, 2) for a constant heat-flux line source, and 3) for a cylinder losing heat under the radiation or convection boundary condition (15). All three solutions eventually converge to the same line which is approximated by:

$$f(t) = \ell n \frac{2\sqrt{\alpha t}}{r_h} - 0.29. \tag{22}$$

Now, substituting for dQ/dz from Equation (21) into Equation (20), the following expression is obtained:

$$\frac{dT}{dz} = \frac{\frac{2\pi K_e}{f(t)} \frac{(T_e - T_h)}{m} + \frac{2 f v^2}{g_c d_i}}{C_p}. \tag{23}$$

The development presented so far is general and it can be used for any type of wellbore completion. The term that changes with the type of wellbore completion, on the right hand side of the above equation is T_h, a cement-formation temperature at any time and depth.

In the case of annular completion, all three modes of heat transfer, conduction, convection and radiation, are present which affect the heat flow between the hot water in the tubing and cement-formation interface. However, in non-annular completion, heat is transferred only by conduction, if it is assumed that the temperature of the inside wall of the casing and water are the same. Hence, in the first case, evaluation of an overall heat transfer coefficient is necessary along with an expression for T_h. In the second case only an expression for T_h is necessary.

First, by taking the case of annular completion, the heat transferred between water and the cement-formation interface is given by the following equation:

$$\Delta Q = 2\pi r_{to} U_{to} (T_f - T_h) \Delta z \tag{24}$$

where U_{to} is based on the outside area of the tubing and Δz is an incremental length. Also, the rate of heat transfer between the cement-formation interface and the formation may be expressed as:

$$\Delta Q = \frac{2\pi K_e (T_h - T_e) \Delta z}{f(t)} . \tag{25}$$

Now, by equating the right hand sides of the above two equations and solving for the cement-formation interface temperature, T_h, the following equation is obtained:

$$T_h = \frac{T_f \, f(t) + \dfrac{K_e}{r_{to} U_{to}} \, T_e}{f(t) + \dfrac{K_e}{r_{to} U_{to}}} . \tag{26}$$

In order to evaluate T_h, an expression for the overall heat transfer coefficient, U_{to}, is required. It may be calculated by accounting for the three heat transfer modes in the annulus. Willhite has developed a procedure for calculating the overall heat transfer coefficient for hot water injection wells (22). The expression he arrived at for an air-filled annulus is:

$$U_{to} = \left[\frac{r_{to}}{r_{ti} h_f} + \frac{r_{to} \ln \left(\frac{r_{to}}{r_{ti}} \right)}{K_{tub}} + \frac{1}{(h_c + h_r)} + \frac{r_{to} \ln \left(\frac{r_{co}}{r_{ci}} \right)}{K_{cas}} + \frac{r_{to} \ln \left(\frac{r_h}{r_{co}} \right)}{K_{cem}} \right]^{-1.0} . \tag{27}$$

Since the thermal conductivity of the casing and tubing is much higher than for the other materials in the wellbore, these constitute a relatively small resistance to the heat flow and can be ignored. Furthermore, the film coefficient, h_f, for turbulent flow of water is generally high enough, in relation to the other terms, so that it can be easily ignored. Thus, with these assumptions, the above equation may be simplified as:

$$U_{to} = \left[\frac{1}{h_c + h_r} + \frac{r_{to} \ln \left(\frac{r_h}{r_{co}} \right)}{K_{cem}} \right]^{-1.0} . \tag{28}$$

Similarly, the simplified equation for the case where insulation is used in the annulus is obtained and expressed as follows:

$$U_{to} = \left[\frac{r_{to} \ln \left(\frac{r_{ins}}{r_{to}} \right)}{K_{ins}} + \frac{r_{to}}{r_{ins} (h'_c + h'_r)} + \frac{r_{to} \ln \left(\frac{r_h}{r_{co}} \right)}{K_{cem}} \right]^{-1.0} . \tag{29}$$

In Equation (28) h_c and h_r are given by the following equations:

$$h_c = \frac{K_{hc}}{r_{to} \ln \left(\frac{r_{ci}}{r_{to}} \right)} \tag{30}$$

and

$$h_r = 1.713 \times 10^{-9} F_{toci} \left[(T_{to} + 460)^2 + (T_{ci} + 460)^2\right] \left[(T_{to} + 460) + (T_{ci} + 460)\right] \quad (31)$$

where

$$K_{hc} = K_{ha} \times 0.49 \, (GR \times PR)^{0.333} \, PR^{0.074}$$

GR = Grashof number

PR = Prandtl number

$$F_{toci} = \left[\frac{1.0}{E_{to}} + \left(\frac{r_{to}}{r_{ci}}\right)\left(\frac{1.0}{E_{ci}} - 1.0\right)\right]^{-1} .$$

E_{to} and E_{ci} are the emissivities of the tubing and casing respectively.

Similarly, h'_c and h'_r in Equation (29) may also be obtained where the insulation is used in the annulus by substituting for the outside tubing radius by the radius of insulation, the outside tubing temperature by the outside insulation temperature and the emissivity of the tubing by the emissivity of the insulation. Thus, the cement formation interface temperature, T_h, given by the expression in Equation (26), may be evaluated for a particular reservoir with known thermal properties.

Now, by substituting for T_h from Equation (26) into the differential Equation (23), the following simplified differential equation may be obtained:

$$\frac{dT}{dZ} + \frac{T}{A} - \frac{aZ + d}{A} = 0 \quad (32)$$

where

a = geothermal gradient, ^{o}F/foot

$$d = \left(b + \frac{2 A f v^2}{J C_p g_c d_i} \right)$$

b = initial bottom-hole temperature

$$A = \frac{m C_p \left(f(t) + \frac{K_e}{r_{to} U_{to}} \right)}{2 \pi K_e} .$$

Equation (32) is a first order linear differential equation. The integrating factor for it is $e^{Z/A}$, and the general solution is obtained as:

$$T(z,t) = aZ - aA + d + c(t) e^{-Z/A} \tag{33}$$

where the function c(t) may be evaluated by applying the boundary conditions as follows: at the bottom of the well, i.e. at $z = 0$, $T(o,t) = T_o(t)$. Thus,

$$C(t) = T_o(t) + aA - d$$

Therefore, the final expression for liquid water temperature as a function of depth and time is:

$$T(z,t) = \left(T_o(t) + aA - d \right) e^{-Z/A} + aZ + d - aA . \tag{34}$$

If the above equation is desired to be solved on a depth-step basis, the following equation relates the temperature of water at the top of a given depth interval to that at the bottom:

$$T(z,t) = \left(T(Z - \Delta Z,\ t) + aA - d \right) e^{-\Delta Z/A} + a(Z - \Delta Z) + d - aA. \tag{35}$$

The overall heat transfer coefficient, U_{to}, is a function of the water temperature and also of the casing and hole temperatures. Since U_{to} is used to obtain the cement-formation interface temperature, which is related to the casing temperature, it is necessary to use an iterative scheme for its solution. A value of U_{to} is first assumed, and a casing temperature is calculated. This value of the casing temperature is used to calculate a new value of U_{to}, which is compared with the assumed value. If the difference between the two is significant, the calculated value of U_{to} is used to arrive at a new casing temperature and so forth.

The friction factor, f, is evaluated using Fanning's correlation which is approximated in the following equation for turbulent flow:

$$f = \frac{0.046}{(N_{Re})^{0.2}}$$

where N_{Re} = Reynold's number.

Equations (24) through (35) are applicable to the annular wellbore completion. In the case of non-annular wellbore completion the only mode of heat transfer is conduction through the casing wall and the cement. Since the conductance of the casing wall is many times higher than that of the insulating cement, it may be ignored. Then, by equating the heat-flow through the cement to the heat diffusion into the formation, an expression for T_h, the cement-formation interface temperature, can be obtained as:

$$T_h = \frac{\frac{K_e}{K_{cem}} \ell n \left(\frac{r_h}{r_{co}}\right) T_e + f(t)\, T_f}{f(t) + \left(\frac{K_e}{K_{cem}}\right) \ell n \left(\frac{r_h}{r_{co}}\right)} \quad . \tag{36}$$

If the above equation is used in place of Equation (26) for T_h in deriving an expression for the temperature of water as a function of depth, then, again, Equation (35) is obtained, except in this case the definition of A is changed as follows:

$$A = \frac{C_p\, m \left(f(t) + \frac{K_e}{K_{cem}} \quad \ell n \frac{r_h}{r_{co}} \right)}{2\,\pi\, K_e} \quad .$$

Therefore, by the use of Equation (35) and the appropriate expression for A, it is possible to calculate the temperature of water as a function of depth in the case of annular and non-annular completion.

The temperature of water at the bottom of the wellbore may be assumed to be in equilibrium with the temperature of formation at that depth. Hence, it may be obtained by the following equation:

$$T_{WBH} = T_{amb} - aZ \quad . \tag{37}$$

Then, starting at the well bottom, i.e. at $Z = 0$, the temperature of water at regular intervals may be calculated until the wellhead is reached. At the wellhead the calculated temperature of water must be equal to or slightly greater than the desired temperature, T_{WH}, calculated in Equation (14). If the calculated wellhead temperature is less than desired, then the temperature of water at the bottom of the well is increased by increasing Z, i. e. by increasing the depth of the wellbore until the desired wellhead temperature is obtained.

While it is essential to meet the temperature requirements at various points in the system, it is equally important to keep the water in liquid phase throughout the water production, energy conversion and waste water injection stages. This is accomplished by keeping the water under pressure. Pressure is maintained above the saturation pressure at the corresponding water temperature. Pressure at the bottom-hole is controlled by the pressure gradient existing in an area, the depth of the wellbore and the reservoir rock flow characteristics. If P_{GR} is the linear pressure gradient in psi per foot then the reservoir static pressure in psi is given by:

$$P_e = P_{GR} \times Z + 14.7 \tag{38}$$

Now, the flowing pressure at the bottom of the wellbore is controlled according to Darcy's law for fluid flow through porous media. Darcy's law is expressed as:

$$m = \frac{1.65 \times \rho_f \times k' \times h' \times (P_e - P_w)}{\mu_f \times \ell n \left(\frac{r_e}{r_w} \right)} \tag{39}$$

where

k' = reservoir rock permeability, Darcy

h' = thickness of productive formation, feet

P_w = reservoir flowing pressure, psi.

Now, the reservoir characteristics, namely the formation permeability, its productive thickness and the radius, may be combined in one parameter, w, as follows:

$$w = \frac{k' \times h'}{\ell n \left(\frac{r_e}{r_w}\right)} . \tag{40}$$

Equation (39) may now be solved for the wellbore flowing pressure, P_w, as:

$$P_w = P_e - \frac{\mu_f \times m}{1.65 \times \rho_f \times w} . \tag{41}$$

P_w must be greater than the corresponding saturation pressure for the water temperature at the bottom of the wellbore. The relationship between the temperature and the corresponding saturation pressure (or the equation for vapor pressure curve) for water is given by the following equation (23):

$$P = (T/115.1)^{4.45} . \tag{42}$$

From Equation (41) it is apparent that for a given reservoir at a given depth, the wellbore flowing pressure decreases as the water flow in the reservoir increases. Thus, it is possible, by adjusting the water flow rate, to keep water in liquid phase at the bottom of the wellbore. Additionally, water should be kept in liquid phase throughout the system. This may be accomplished by the use of a submergible pump. Use of a pump may accomplish two purposes. It can lift and transport water to the power plant and also help to keep it above the saturation pressure at all points.

The pump horsepower in a given geothermal system may be calculated by writing the mechanical energy balance between the pump inlet and the wellhead. For a non-compressible fluid such as water, the mechanical energy balance across the pump may be expressed as:

$$W_f = \frac{g}{g_c}(Z_2 - Z_1) + \frac{v_2^2 - v_1^2}{2g_c} + \frac{P_2}{\rho_2} - \frac{P_1}{\rho_1} + \frac{2fv_2^2\,(Z_2 - Z_1)}{g_c\,d_i}. \tag{43}$$

Subscripts 1 and 2 are applied to the conditions at the pump inlet and the wellhead respectively. The above equation may be simplified by making the following assumptions:

1. the reference point for depth is a point at the pump inlet, therefore, $Z_1 = 0$;
2. velocity at the pump inlet is negligible compared to the velocity at the wellhead, i.e. $v_1 = 0$; and
3. liquid water is non-compressible, therefore, $\rho_1 = \rho_2 = \rho_f$.

Now, Equation (43) may be rewritten as:

$$W_f = \frac{g}{g_c} Z_2 + \frac{v_2^2}{2g_c} + \frac{P_2 - P_1}{\rho_f} + \frac{2f\,v_2^2\,Z_2}{g_c\,d_i} \tag{44}$$

The left-hand side of the above equation represents the pump work in foot-pound per pound of water lifted. The velocity of water at the wellhead may be expressed as:

$$V_2 = \frac{4 \times m}{\pi\,\rho_f\,d_i^2} \tag{45}$$

P_2 and P_1 are pressures at the wellhead and at the bottom of the well-bore, therefore, $P_2 = P_{WH}$ and $P_1 = P_w$. Wellhead pressure must be high enough not only to keep the water in liquid phase at that point but also to keep it from flashing at any point in the surface gathering system or in the heat-exchanger in the power plant. Thus, P_{WH} consists of three components as follows:

$$P_{WH} = (T_{WH}/115.1)^{4.45} + \frac{2 f v_{pipe} D_{LP}}{g_c d_{pipe}} + \begin{matrix}\text{pressure drop}\\ \text{in}\\ \text{heat-exchanger.}\end{matrix} \qquad (46)$$

The first term on the right hand side of the above equation represents the saturation pressure corresponding to the wellhead temperature, T_{WH}, and the second term accounts for the frictional loss in the surface pipeline. Pressure loss in the heat-exchanger is a function of its design but it is always specified, and hence it is a known quantity. Water velocity in the pipe may be expressed as:

$$v_{pipe} = \frac{4 \times m}{\pi \rho_f d_{pipe}^2} \qquad (47)$$

With the proper substitution from Equation (45) through (47), Equation (44) may be expressed in detail as:

$$W_f = \frac{g}{g_c} Z_2 + \frac{1}{2g_c} \left(\frac{4m}{\pi \rho_f d_i^2} \right)^2 + \frac{1}{\rho_f} \left\{ P_w - \left[(T_{WH}/115.1)^{4.45} + \frac{2 f D_{LP}}{g_c d_{pipe}} \left(\frac{4m}{\pi \rho_f d_{pipe}^2} \right)^2 + \Delta P_{H.E.} \right] \right\} + \frac{2 f Z_2}{g_c d_i} \left(\frac{4m}{\pi \rho_f d_i^2} \right)^2 . \qquad (48)$$

W_f now gives the pump work required to keep the water in liquid phase throughout the water production and energy conversion systems. Thus, the horsepower requirements of the pump may be obtained by the following conversion, assuming 70 percent pump efficiency:

$$H.P. = \frac{W_f \times m}{33500 \times 0.70} . \tag{49}$$

In terms of the electric power requirements of the pump, the above equation may be expressed as:

$$\text{Electric Power, KW} = \frac{H.P. \times 0.746}{0.75} \tag{50}$$

assuming 75 percent conversion efficiency. The electric power requirement of the pump is important in that it practically determines the net amount of power available for sale in a given geothermal system. The net amount of power available for sale may be expressed as:

Net power for sale = Gross power generated - Power utilized by pumps - Power utilized in the power plant.

While the gross amount of power generated is a function of temperature and the amount of hot water available at the power plant inlet, the amount of power utilized by the pumps is a function of the flow rate of water, flowing pressure at the bottom of the wellbore and the wellbore design. In-house power utilized at the generation facilities is normally a small fraction of the gross power generated. Furthermore, the temperature of water at the plant inlet depends upon the temperature at the bottom of the wellbore and the wellbore design. Because of these inter-relationships, it may be concluded that the net amount of power for sale depends upon four major variables:

1. temperature of water,
2. pressure at the bottom of the wellbore,
3. wellbore and gathering system design, and
4. the flow rate of water.

Except for the third variable which is subject to choice, the remaining three are characteristics of a particular geothermal reservoir. Through the mathematical model, it is now possible to calculate the net amount of power for sale under a given set of variables described above. The details of the calculational method using this model are described in a later chapter.

The geothermal system model, expressed mathematically, deals with the movement of water from the reservoir to the wellbore and up to the power plant. Water coming out of the power plant is assumed to be distributed to the injection wells through surface pipelines. As it is pointed out earlier in the scope of this study, and also in the beginning of this chapter, only a few of the primary variables associated with the water injection system are considered here. The five variables considered for the design of the injection system are:

1. distance between the power plant and the injection well, D_{LPI};
2. diameter of the pipeline for water transmission, d_{IPIPE};
3. number of injection wells, N_{INJW};

4. diameter of the injection well, d_{INJ};

5. depth of the injection well, Z_{INJ}.

These all may be considered as averages in each catagory. The main reason behind the choice of these variables is that they influence the cost of the injection system. While no mathematical development of the injection system is incorporated in this study, the inclusion of the injection system is necessary to assess the cost of power from geothermal energy. Development of the model is viewed as a tool to achieve the objective of assessing the cost of geothermal power existing under various naturally occurring conditions. Towards fulfilling this goal, the second part of the study, namely, the development of the economic model, is presented in the next chapter.

CHAPTER IV

DEVELOPMENT OF THE ECONOMIC MODEL

One of the important prerequisites for the successful exploitation of any energy resource is at least a competitive if not an economic advantage over the use of other alternative resources. In order to stimulate interest in the development of any resource, an assessment of its cost under optimum producing conditions must be made. Accordingly, in this chapter the basis for a cost evaluation of the previously described geothermal power system will be discussed. Calculational procedures and data development in model application are deferred for the next chapter.

The economic incentive to develop geothermal power, of course, must be the profit potential of the investment. While there are various ways to measure the "attractiveness" of an investment, one of the most widely used profitability yardsticks is the "rate of return" on the investment. It is defined as the interest rate that reduces the present worth of a time series of receipts and disbursements to zero (23).

In economic terms, the rate of return represents the rate of interest earned on the unrecovered balance of an investment. Mathematically, the rate of return may be defined as the value of (i) that satisfies the following equation:

$$0 = \sum_{t=0}^{n} \frac{X_t}{(1 + i)^t} \tag{51}$$

where

X_t = cash flow for year t

n = total economic life of the project.

Cash flow for any year is defined as a net result of a series of receipts and disbursements during that year. It is calculated, in this dissertation, by the following general equation:

Cash flow = Gross Income - Expenses - Interest on Borrowed Money - Taxes - Capital Expenditures - Principal Payment + Borrowed Money. (52)

Since it is necessary to arrive at a cash flow value for every year of the project, each term on the right hand side of the above equation must be evaluated every year. Gross income in this case is the amount of money received by selling net electric power available. Thus, it is a product of the net amount of electric power sold in a year in KWH and the selling price. By adjusting the selling price and hence gross income, the cash flows for each year may be changed until Equation (51) is satisfied for the desired rate of return (i). Thus for every desired rate of return there is a selling price associated with it. Let (S_p) represent unit selling price in dollars per KWH corresponding to the desired rate of return (i) and (NPS) be the net amount of power available for sale each year in KWH. Therefore,

$$\text{Gross Income} = S_p \times \text{NPS}. \tag{53}$$

To generate this gross income, of course, the prior investment in various phases of geothermal power development is necessary. The expenditures associated with it may be divided into the following five main catagories:

1. land,
2. exploration,
3. drilling and development,
4. power plant,
5. injection system.

In each catagory, there are two types of expenditures. The first catagory is "expensed" expenditures. These are defined as the ones that may be deducted, for tax purposes, from the gross income in the year they occur. They are usually related to manpower, maintenance and operations, etc. The other kind of expenditures are the "capitalized" ones. These are associated with the cost of equipment. "Capitalized" expenditures are deducted as depreciation, for tax purposes, over the years of useful life of an asset. The "capitalized" and "expensed" type expenditures that are considered in this study are shown in Table I.

Expenditures in the first two catagories, land and exploration, mainly depend upon the area leased or the land covered for exploration. Thus, they are expressed as a function of the acreage required.

TABLE I

A LIST OF "CAPITALIZED" AND "EXPENSED" EXPENDITURES IN GEOTHERMAL POWER DEVELOPMENT

Catagory	Capitalized	Expensed
Land	Lease bonus	Lease rentals and royalties
Exploration	Warehouses, equipments, trucks or autos, drilling of successful wells, well-bore equipment, etc.	Salaries of all people, regular supplies and maintenance, drilling of unsuccessful holes, etc.
Drilling and development	Equipping successful wells, transmission equipment, etc.	Intangible drilling expenses, maintenance, etc.
Power plant	All equipment, initial cost of secondary fluid	Maintenance and operating expenses
Injection system	Piping, drilling of wells, etc.	Maintenance, drilling of unsuccessful wells if any, etc.

Similarly, expenditures in other catagories may be expressed in terms of some other convenient basis. Since the objective is to use the economic model in conjunction with the mathematical model developed in the previous chapter, it is desirable to choose a basis that is easy to match with the variables in the mathematical model. For example, in expressing the cost of the pipeline it is convenient to express it in terms of dollars per foot for a particular diameter of the pipeline. The diameter and length are the two variables that affect the pressure and temperature of water throughout the system. Thus, the basis of length and diameter to express the cost of the pipeline is consistent both in terms of the economic model of the geothermal system as well as the mathematical model.

With the above reasoning, the basis of cost estimation of various expenditures in each catagory of the geothermal development are shown in Table II along with the units used in expressing the cost. Items of expenditures in the last three catagories are per production or injection well as the case may be. Therefore, the total expenditures are dependent upon the number of production or injection wells required in a given development project. From the above discussion and with the help of Tables I and II, two terms, namely "Expenses" and "Capital Expenditures" in Equation (52) may be evaluated once the technological variables, as described in the derivation of the mathematical model, are established for a given geothermal system.

The remaining terms in Equation (52) are very much interrelated

TABLE II

BASIS FOR ESTIMATING COST OF VARIOUS ITEMS IN A GEOTHERMAL POWER PROJECT

Catagory	Item of Expenditure	Basis and Units
Land	Lease bonus	Area leased; $/Acre
	Lease rental	Area leased; $/Acre/Yr.
	Lease royalty	Water produced; $/Pound
Exploration	"Capitalized" cost	Area explored; $/Acre/Yr.
	"Expensed" cost	Area explored; $/Acre/Yr.
Drilling and development	Intangible drilling	Drilling depth, hole diameter; $/Ft. for a given hole diameter
	Casing and tubing	Setting depth, diameter; $/Ft. for a given diameter
	Insulation (subsurface and surface)	Thickness, diameter and type; $/Ft. length for a given thickness and diameter.
	Submergible pump	Horsepower; $/Pump
	Wellhead equipment	Standard available; $/Well
	Surface pipeline	Length and diameter; $/Ft. for a given diameter
Power plant	Power plant installed	Size of the power plant; $/KW installed capacity
	Operations and maintenance	Power plant size and cost; $/KW
Injection system	Surface pipeline	Same as in drilling and development catagory
	Intangible drilling	
	Casing	

in that they depend on the investment structure desired for the project. There are basically two different ways in which initial investment may be generated. In the case of equity financing, money is raised internally either from depreciation reserves or via retained earnings, or by selling stock. The second method of financing is raising money by debt, for example, by borrowing from the bank by mortgaging property. Each method has some advantages and disadvantages. It is a common practice in the industry to generate capital using both methods and maintaining some "optimum" financial structure of the investments.

The discounted cash flow method, used here to evaluate the profitability, determines the rate of return on the equity portion of the investment. Assuming that the capital is raised by equity as well as debt financing, interest is paid on the borrowed portion of the capital for as long as all the borrowed money is not fully returned. Of course, every year interest is paid only on the unpaid balance. The interest rate is agreed upon at the time of borrowing. Similarly, "principal," i.e. the amount of borrowed money to be returned every year, is agreed upon initially. Borrowed money is returned only after the project begins to generate revenues. Therefore, the decisions made in the initial stages of the project development determine the amount of money to be borrowed, the principal to be returned and also the interest due every year during the initial development of the project or until all the borrowed money is returned.

The only remaining term yet to be determined in Equation (52) is the taxes. They may occur in various ways. If the examples in the petroleum or existing geothermal (steam) industry are followed, then the total tax obligations may involve production taxes, ad valorem taxes and, in addition, the usual state and federal income taxes. However, by the same token, this tax burden may be somewhat reduced if the depletion allowance, common in petroleum and mining operations, can be taken. These taxes often vary with locality and there may be no precedent for establishing the basis for applying them. Therefore, to overcome this dilemma, it is assumed in this study that the main tax obligations are federal income tax. By varying the tax rates, however, it is possible to accommodate, at least approximately, other tax obligations deemed necessary in a particular situation.

Federal income tax is calculated by the following formula:

$$\text{Taxes} = (\text{Gross Income} - \text{Expenses} - \text{Interest on Borrowed Money} - \text{Depreciation}) \times \text{Tax Rate} \qquad (53)$$

Except for the depreciation and tax rate, the remaining terms in the above equation are already discussed. Depreciation depends upon the method used for depreciating an asset and the assumed salvage value at the end of the project. The straight line depreciation method is used here since it is common in industry. In this method an equal increment is deducted every year. Due to the uncertainty involved in estimating the salvage values and also since their effect is almost negligible, the assumption is made that all equipment has zero salvage value. The other unknown term in the above equation is the tax rate. This is determined by the existing or anticipated tax rate of the company, and is known at the time of economic evaluation.

In the above discussion, each term on the right hand side of Equation (52) is defined. This, now, allows the calculation of cash flow for each year of the project and, hence, the rate of return, defined in Equation (51), may be determined for a given selling price of electricity. Conversely, the selling price may be arrived at for a given desired rate of return. However, in order to arrive at numerical results, a data base, compatible with the technological and economic models, and a general scheme of solution must be developed. This phase of the study is dealt with in the next chapter.

CHAPTER V

DATA DEVELOPMENT AND DESCRIPTION OF THE SOLUTION SCHEME

In the last two chapters a techno-economic model of the geothermal system is developed. The technological part of the model mathematically describes the system, as defined for the purposes of this study, thus establishing the inter-relationship among various design variables as well as geological conditions. The economic part of the model considers the costs associated with each phase of the geothermal power development and determines the required selling price of electricity for a desired rate of return on the investment.

Development of the techno-economic evaluation model is only a partial fulfillment of the objective of this work. In order to apply the model to assess the cost of producing geothermal power, numerical solutions based on an assumed set of initial conditions must also be obtained. Furthermore, the data obtained in the solution must be compatible with both the technologic and economic parts of the model. In this chapter, first the data base is developed and then the solution scheme for obtaining the results is described.

Data Development

The types of data necessary for a numerical solution of the model may be classified according to the five primary phases of the geothermal investigation. For each phase, data for the mathematical model and also for the economic model are required. For the economic model the data needed is for cost estimation and this basis is presented in Table II. Additionally, a number of assumptions regarding the financial structure of a company and the development scheduling are necessary. These are presented at the end of this chapter. In developing the cost data, an attempt was made to obtain costs of various items as they were priced in early 1973. In certain instances, especially regarding lease and exploration costs, there are no established numbers and hence the assumed costs should be viewed as estimated values rather than as factual data.

The data-base, as it relates to technological aspects of the model, is selected with due consideration given to equipment availability and limiting operating conditions under which the equipment is recommended for normal use. The data-base presented here is common for all calculations performed in the course of this work.

Land

The first phase in geothermal power development is the leasing of land for exploration and development purposes. Basic data assumed regarding this cost item are:

1. production or injection well spacing: 40 acres/well,
2. lease bonus: \$5.00/acre,
3. lease rent: \$1.00/acre/year,
4. lease royalty: \$0.025/1000 pounds of water.

Lease bonus is a cash payment made to the lease holder to acquire a lease on a property. It is paid only once during the life of a lease, in the beginning. After the lease agreement is reached, active exploration for the geothermal resources begins. In the years when the land is being developed for power production, annual lease rental is normally paid. Once water and power production commences, lease rental is replaced by lease royalty, which depends on the amount of water produced.

Exploration

The exploration activity may be carried out in two phases. The first phase consists of general area surveys, made to collect data on hydrology and geothermal gradients. Schoeppel, et. al., have shown how to use commonly available data to evaluate the regional geothermal gradient situation (24). Detailed geophysical and geological work follow the general area study. Exploration expenses are associated with the equipment and manpower needed to conduct these investigations. For the exploration work mentioned above the following costs are assumed:

1. equipment expenses: \$50.00/acre,

2. manpower expenses: \$100.00/acre.

In addition to the activities mentioned above, exploratory drilling must be done. The number of exploratory wells that are needed to identify and evaluate the resource depends on many factors; here it is assumed that one year is spent in exploration and during this period two exploratory wells are drilled. It is noted that drilling for geothermal wells is quite similar to the drilling of petroleum wells (25). However, due to the unfamiliarity of an area, normally more than average expenditures occur in drilling exploratory wells. It is assumed that intangible drilling expenses for exploratory wells are 20 percent higher than for development wells.

Development

A successful exploration program leads to the development phase of the geothermal project. This phase includes the drilling, completing and connecting of the necessary number of water production wells to the power plant. Before the actual drilling starts, the area may need to be prepared for the moving-in of the drilling rig and other equipment. Arangements are also necessary for water and power supply. Costs associated with these items are included in the intangible drilling expenses. Intangible drilling expenditures vary with many factors, such as depth of drilling, hole diameter, formation type, drilling fluid, etc. However, the two main factors that generally contribute most are depth and hole diameter. Intangible drilling costs as a function of total depth are shown in Table III. Variations in cost due to hole size are taken into account by the use of normalization factors. These factors are also shown in the table. Drilling costs are multiplied by an appropriate normalization factor to determine the total intangible costs. The drilling cost data used in this study as presented in Table III are based on statistics compiled by the American Petroleum Institute (26).

Depending on the type of well completion, production wells need casing and/or tubing strings. The main concern in selecting a casing and tubing is the recommended setting depth. There are three types of principle loadings, namely tensile load, collapse pressure and burst pressure that affect the setting depth (27). Besides the setting depth, the diameter of the casing or tubing and its thickness are also open for selection. Cost of a casing or a tubing may be expressed as a function of its diameter and recommended setting depth. A wide range of selection of casing and tubing is available from a large number of manufacturers. An example of the type of data used in this study is shown in Table IV. It is based on the data furnished by one manufacturer of casing and tubings (28). Hole diameter and recommended casing size are related. This mainly depends on the minimum clearance required for a casing coupling. Common practices observed in the industry are based on equipment availability. Table V shows one such correlation between casing size and hole diameter (29).

TABLE III

DATA USED IN EVALUATING INTANGIBLE DRILLING COSTS

Depth in Feet	Intangible Drilling Cost, Dollars/Foot	Hole Diameter, Inches	Normalization Factor
0-1,250	5.25	5.500	0.75
1,250-2,500	5.50	6.125	0.80
2,500-3,750	5.80	6.750	0.85
3,750-5,000	6.25	7.875	0.90
5,000-7,500	7.00	8.625	0.95
7,500-10,000	8.75	10.000	1.00
10,000-12,500	11.00	10.625	1.06
12,500-15,000	16.00	11.625	1.12
15,000-20,000	25.00	12.750	1.20
Over 20,000	35.00	14.000	1.30
		16.000	1.50
		18.500	1.80
		24.000	2.00

TABLE IV

EXAMPLES OF COST DATA USED IN SELECTING TUBING AND CASING

USS GRADE N-80 SEAMLESS CASING

Size O. D., Inches	Nominal Wt. /Ft. Lbs.	Recommended Setting Depth, Feet	Cost $/100 Feet
4 1/2	11.6	10,580	226.65
4 1/2	13.5	13,480	263.78
5	15.0	11,770	287.31
5	18.0	16,080	344.76
5 1/2	17.0	10,490	320.49
5 1/2	20.0	13,870	377.06
5 1/2	23.0	16,740	433.60
6 5/8	24.0	9,790	443.09
6 5/8	28.0	12,290	516.94
6 5/8	32.0	15,850	590.79
7	23.0	7,230	422.60
7	26.0	9,320	468.82
7	29.0	11,470	522.91
7	32.0	13,570	577.00
7	35.0	15,660	631.11
7	38.0	17,090	685.20
7 5/8	26.4	6,480	484.70
7 5/8	29.7	8,500	545.29
7 5/8	33.7	10,860	618.74
7 5/8	39.0	13,850	716.13
8 5/8	36.0	7,580	647.58
8 5/8	40.0	9,470	719.54
8 5/8	44.0	11,370	791.48
8 5/8	49.0	13,530	881.42
9 5/8	40.0	5,840	723.04
9 5/8	43.5	7,200	786.32
9 5/8	47.0	8,450	849.57
9 5/8	53.5	10,390	967.08
10 3/4	51.0	6,110	918.21
10 3/4	55.5	7,470	999.24
11 3/4	60.0	6,030	1078.26
13 3/8	72.0	4,990	1347.07
13 3/8	77.0	5,870	1440.62
13 3/8	85.0	7,280	1590.30
13 3/8	98.0	9,990	1833.51

TABLE V

CORRELATION OF THE CASING SIZE AND THE HOLE DIAMETER

Casing Size, Nominal O. D., Inches	Hole Diameter, Inches
4.500	5.500
5.000	6.125
5.500	6.750
6.625	7.875
7.000	8.625
7.625	10.000
8.625	11.625
10.750	12.750
11.750	14.000
13.375	16.000
16.000	18.500
20.000	24.000

In an annular wellbore completion, the area between the casing and tubing may be partially or fully covered with an insulating material. Cost of insulation depends upon the type of material used, tubing diameter, and insulation thickness. Cost data for a calcium silicate based commercial insulation for one particular tubing diameter are shown in Table VI. Data for various other diameters used here is available in the manufacturer's literature (30).

Hot water available at the bottom of the wellbore must be transported to the power generating facilities. Submergible pumps are particularly well suited to achieve this result due to their high volume capacity and low power requirements (31). Presently, submergible pumps are manufactured on a large scale and it is possible to operate them to depths of 20,000 feet and temperatures of 500°F. Electric motors available for these pumps have horsepower ratings above 600 H.P., if desired. The cost of a submergible pump is primarily a function of the pump horsepower. It affects the equipment cost as well as the cost of installation. Cost data used in this study are shown in Table VII. These are based on the manufacturer's price schedule (32). The cost of the wellhead equipment varies with the diameter of the flow lines, wellhead pressure, etc. It is assumed here that $5,000 is spent on each wellhead facility. The cost of surface pipelines is shown in Table VIII. It is mainly a function of size (33). Insulation material used for insulating the surface pipeline is assumed to be commercially available glass wool insulation. Cost for this type of insulation is

TABLE VI

BASIC DATA FOR SUBSURFACE INSULATION COST
FOR 2 3/8 OD TUBING

Insulation Thickness, Inches	Cost, Dollars/Foot
0.5	0.50
1.0	0.75
1.5	1.00
2.0	1.50
2.5	2.00
3.0	2.40
3.5	2.75
4.0	3.00
5.0	3.25

TABLE VII

DATA USED IN EVALUATING THE COST OF SUBMERGIBLE PUMPS

Pump Horse Power, HP	Equipment Cost, Dollars	Installment Cost, Dollars
30	10,200	1,500
40	14,000	1,750
60	15,500	1,850
80	17,700	2,000
100	18,500	2,100
120	20,000	2,400
150	20,500	2,750
180	21,000	3,000
260	23,000	4,000
320	28,000	4,400
400	35,000	5,000

TABLE VIII

COST OF SURFACE PIPELINE

Pipe Size, Nominal O.D., Inches	Cost, Dollars/100 Feet
1.0	50.00
1.5	75.00
2.0	100.00
2.5	125.00
3.0	150.00
3.5	170.00
4.0	200.00
5.0	235.00
6.0	260.00
8.0	300.00

shown in Table IX (30).

In addition to the cost data, wellbore heat transfer calculations require the thermal properties and data for the various equipment used in the wellbore completion. Table X shows the data used in this study. The properties of water are available in the literature (34).

Power Plant

Installed capacity and equipment size variation, due to the level of water temperature available at the power plant inlet, have a great influence on the cost of the power plant. Inlet water temperature at the plant is, of course, also a primary factor in cost evaluation. Because of heat losses in the surface and subsurface transportation of water, the quality of the geothermal resource deteriorates as the distance increases between the geothermal reservoir and the power plant. This will tend to limit plant sites to the close vicinity of the water production area and plant sizes to the smaller capacities, perhaps below 25 MW. The unit cost, in terms of dollars per kilowatt installed, for these plants is expected to be little influenced by the size variation. The estimated power plant cost for the temperature range of 325-450°F considered here is \$230 per installed kilowatt (35). Annual operating and maintenance cost for the combined water and power production system is taken as 5 percent of the power plant installation cost. This becomes applicable whenever the power plant goes on-stream. Finally, a power plant size of 10 MW is selected as a basis for all calculations.

TABLE IX

BASIC DATA FOR COST OF SURFACE PIPELINE INSULATION FOR TWO INCH PIPE

Insulation Thickness, Inches	Cost, Dollars/Foot
1.0	0.60
1.5	0.75
2.0	1.00
2.5	1.20
3.0	1.50
3.5	2.00
4.0	3.00
5.0	4.25
6.0	5.75

TABLE X

THERMAL PROPERTIES DATA USED IN
TEMPERATURE CALCULATIONS

Data Name			Data Value and Units
1.	Thermal Conductivity		BTU/Hr., Ft., ^{o}F
	a.	Annular Fluid	0.026
	b.	Insulating Cement	0.300
	c.	Reservoir Formation	1.000
	d.	Subsurface Insulation	0.050
	e.	Surface Insulation	0.040
2.	Diffusivity		$Feet^2/Hour$
	a.	Reservoir Formation	0.029
3.	Emissivity		Dimensionless
	a.	Tubing	0.9
	b.	Casing	0.9
	c.	Insulation	0.5

Injection System

The principal cost items of the injection system, namely the distribution pipeline, intangible drilling expense of the disposal wells, and the casing are taken to be identical in cost to the items covered in the development phase. Therefore, Tables VIII, IV and III are used respectively to arrive at the expense of the above items. The overall cost is arrived at by assuming that one injection well is required for every three producing wells and each injection well is 3000 feet deep. Also, it is assumed that each injection well is equipped with 10-3/4 inches O.D. casing. The recommended hole size for the injection wells, as taken from Table V, is 12-3/4 inches.

Assumptions

In addition to the foregoing, a number of additional assumptions are required to effect a numerical solution. Some of these are quite general in concept whereas others specifically define the economic based used in the evaluation. A list of all further assumptions is summarized below:

1. Reservoir productivity is assumed to remain unchanged during the life of the project.

2. Thermal and physical characteristics of the produced fluids and associated materials remain unchanged during the life of the project.

3. The time function f(t) is evaluated annually at t = 1/2, 1-1/2, 2-1/2, ...etc. years.

4. The power plant load factor is 100 percent.

5. Power consumption by the plant is five percent of the power generated.

6. Success in exploration is 100 percent.

7. Following one year of exploration, three years are required for development drilling and power plant construction.

8. The power plant goes on-stream at full capacity starting the fifth year.

9. The average ambient temperature is 75°F.

10. The "desired rate of return" is ten percent (unless specified otherwise).

11. During the exploration and development phases of the project, 65 percent of all the tangible expenditures are financed by borrowed capital. The remaining is raised internally.

12. Interest on the borrowed money is ten percent.

13. Money borrowed during the exploration and development period is paid back in five equal payments starting in the year in which power generation begins.

14. No more borrowed capital is needed after the power plant starts operating.

15. Tax rate is 50 percent of the taxable income.

16. No salvage value remains at the end of the economic life.

17. The submergible pumps must be replaced after ten years of operation.

18. All tangible expenditures have a ten percent overhead expense payable at the time they occur.

Solution Scheme

A techno-economic basis for assessing the geothermal power system is afforded by the mathematical and economic models developed in previous chapters. These models are used in all cost evaluations. The cost of geothermal power would be expected to depend to a large extent upon the expenditures associated with the development of the geothermal power system. In turn, the development expenditures depend upon the choice of design variables and the natural surroundings existing at the location under consideration.

In geothermal resource evaluation, the physical circumstances of interest are:

1. geothermal (geophysics),
2. hydrological, and
3. geological.

These determine the availability of power at the bottom of the wellbore. Natural surroundings are unchangable and are independent variables in the mathematical model. A second set of variables is associated with the design of the system. Design and physical system variables are identified in Figure 6.

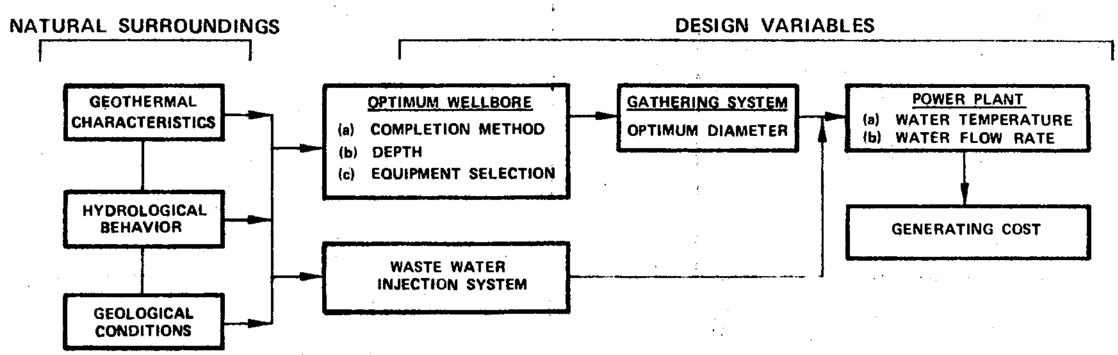

Figure 6. Natural Conditions and Design Variables Affecting the Power Generation Cost and Studied in This Research

The objective of this section is to outline a method to evaluate the cost of power under select design conditions and given natural surroundings. To accomplish this objective, a step-wise procedure is undertaken whereby the mathematical model is first solved with the chosen and given variables, a cost is then allocated to each item of the development, and finally the economic model is solved for the cost of power under thoses circumstances. The solution scheme is undertaken in three phases:

I. Solution of the mathematical model to determine the physical system design;

II. Allocation of costs associated with the construction of the physical system designed in Phase I;

III. Solution of the economic model to assess the cost of power.

Phase I

The mathematical model must first be solved in order to obtain the design of a water production and transportation system that meets the water flow and temperature demands at the power plant inlet and which is also compatible with the natural surroundings. Therefore, in the solution, the power plant design variables are first selected, namely the required water temperature at the plant inlet, and the installed plant capacity. Then, the four physical circumstances involved, namely temperature gradient, pressure gradient, a parameter representing reservoir flow characteristics and water flow rate per well are chosen. The choice of these variables, in practice, would be based on the demand for power in a given location and the results of the exploration in the area. Then, with the assumed surface pipeline diameter, the temperature and pressure required at the wellhead may be calculated. Subsequently, the choice of the wellbore completion method is made and with an assumed diameter of flow string, a wellbore depth is calculated that satisfies the pressure and temperature requirements at the wellhead.

A step-wise scheme of the solution of the mathematical model is presented below:

1. Choose the power plant size, P_{CAP}.

2. Choose the required hot water temperature at the plant inlet, T_{PI}.

3. Determine, from Figure 3, the water consumption rate, W.

4. Calculate, using Equation (1), the total flow rate of water required. Load factor is assumed.

5. Calculate the total number of production wells, N_{PW}, choosing the flow rate of water per well and using Equation (2).

6. Calculate the total number of wells, N_T, from Equation (4), assuming the ratio of production to injection wells, K.

7. Calculate with the given well spacing the total land area required, L_{TOTAL}, from Equation (5).

8. Calculate from Equation (6) the average distance between each well and the power plant, D_{LP}.

9. Determine the required water temperature at the wellhead, T_{WH}, from Equation (14), choosing the nominal size of the surface pipeline from Table VIII and the insulation thickness from Table IX.

10. Select either the annular or the non-annular wellbore completion method. Calculate the minimum wellbore depth by using the following relationship:

$$\text{Minimum depth} = \frac{T_{WH} - T_{AMB}}{-a}$$

Assume the minimum depth as the setting depth for the tubing and casing.

11. In the case of non-annular completion, go to Step 16; otherwise continue.

12. Choose from Table IV the minimum tubing size that satisfies the setting depth requirement. Determine the minimum casing size from the same table with at least two inches clearance between the tubing and the casing.

13. Determine the hole diameter for the wellbore from Table V.

14. Decide on the insulation between the tubing and the casing. If insulation is desired, choose insulation thickness from Table VI.

15. Calculate the water temperature at the wellhead, choosing an appropriate depth-step size (500 feet is used here). Also, use Equation (35) and appropriate values of A and d and evaluate T_{WBH} from Equation (37). Go to Step 19.

16. Choose from Table IV the minimum casing size that

satisfies the setting depth requirement.

17. Determine the hole diameter from Table V.

18. Calculate the wellhead water temperature, with the appropriate values of A, d, T_{WBH}, and depth-step size.

19. Compare the calculated wellhead water temperature in Step 15 or Step 18 with T_{WH} in Step 9. If the calculated temperature is less than T_{WH}, increase the minimum wellbore depth by a small increment (100 feet is used here) and repeat Steps 11 through 18.

20. Calculate the wellbore flowing pressure, P_W, from Equation (41) for a given value of the parameter representing reservoir flow characteristic "w".

21. Determine the horsepower of the submergible pump by solving Equations (48) and (49).

22. Calculate the electric power used by each submergible pump from Equation (50).

23. Calculate the net amount of power available for sale from the geothermal system.

Phase II

In the above step-wise procedure, selection of all the items of expenditure, as outlined in Table II, is made so that Phase II of the solution scheme may be carried out. In this phase the purpose is to assign a cost to each expenditure required in geothermal power development. The step-wise procedure is as follows:

1. Calculate the lease bonus and yearly lease rental from the assumed unit cost and the total land required, L_{TOTAL}, determined earlier.

2. Calculate the annual lease royalty based on the unit cost and the total water produced, W_{TOTAL}.

3. Arrive at the "capitalized" and "expensed" exploration cost for each year of the exploration from the given cost data.

4. Calculate the intangible drilling expenses from Table III, with the depth and hole size of each wellbore determined.

5. Calculate the tubing and/or casing expenses from Table IV.

6. Calculate the cost of insulation from Table VI, only in the case of annular completion with insulation.

7. Determine, using Table VII, the equipment and installation cost of the submergible pump. When the horsepower of the pump, as derived from Equation (49), is between the two numbers listed in the table, the costs corresponding to the higher number are taken for the calculation. (This method is used throughout the cost allocation procedure.)

8. Wellhead equipment is assumed to be standard for each well as mentioned earlier.

9. Determine the cost of the surface pipeline and insulation from Table VIII and Table IX, respectively.

10. Calculate the cost of the power plant and operation and maintenance based on the given data.

11. Arrive at the cost of the waste water pipeline, injection well drilling and equipment from Table VIII, Table III and Table IV, respectively.

Cost allocation in Steps 3 through 11 may best be done on an individual well basis. Then, according to a specific plan of project development, it becomes simple to arrive at the total annual costs and hence the cash flows as derived in the last phase of the solution scheme.

Phase III

In the first two phases of the solution scheme, equipment selection and cost allocation is completed. The purpose of the last phase is to calculate the cost of power for the desired rate of return or vice versa. As was mentioned earlier, the discounted cash flow method is used in arriving at the cost of power or the rate of return. The step-wise procedure is as follows:

1. Choose a time schedule for the geothermal power development, i.e. choose a) the number of years planned for exploration (1 year is used here), b) the number of years planned for development drilling (3 years are used here) and c) the total economic life of the geothermal project (20 years are assumed in this study).

2. Choose the number of exploration wells to be drilled per year of exploration (2 wells are used here).

3. Calculate the number of production wells drilled per year of development. It is equal to the total number of wells divided by the

years planned for the development.

4. Calculate the yearly expenditures due to land, exploration and production wells starting from year 1 and proceeding to the end of the development period.

5. Calculate the total expenditures for the power plant.

6. Determine the annual expenditures due to power plant construction for each year of the development period by dividing the total expenditures equally for each year of the development.

7. Determine the annual operation and maintenance expenses for the system.

8. Choose a number for the cost of power to initialize cash flow calculations. Determine the annual revenues.

9. Divide the annual expenditures, as per Table I, into capitalized and expensed types for each year of the total life of the project.

10. Calculate the depreciation for each year of the project.

11. Determine the amount of money borrowed every year and the annual interest paid on the borrowed money.

12. Calculate the yearly installment to be paid every year of the project.

13. Arrive at the annual tax obligations and calculate the cash flows for each year.

14. Solve Equation (51) for the rate of return on the investment.

15. If the calculated rate of return is less than the desired, then increase the cost of power and repeat Steps 13 and 14. If the

calculated rate of return is greater than the desired, decrease the cost of power and repeat Steps 13 and 14.

16. Repeat Step 15 until the calculated rate of return is the same as the desired one. The corresponding cost of power at that point is the cost of power required to obtain the desired rate of return.

With the solution scheme described above and based on the data and assumptions presented earlier, all the calculations are made towards fulfilling the objective of this study. The results, discussion, and conclusions of the study are presented in the next chapter.

CHAPTER VI

RESULTS AND CONCLUSIONS

In accordance with the primary purpose of this dissertation, calculations are made to assess the cost of geothermal power under various design conditions and naturally occurring surroundings. A geothermal system chosen for the cost evaluation and a techno-economic model describing the system are presented in earlier chapters. In the last chapter, necessary data were developed and a solution scheme was described. Since the solution involves the use of iterative procedures as well as storage of considerable data, a computer program was written to assist in arriving at the numerical results. The step-wise calculational procedure used in solving the problem is shown in the Appendix. The final objective of all the calculations is to determine the cost of power under the selected design parameters and chosen natural surroundings.

Since the pressure and temperature of water are of utmost importance in the geothermal system design, the following three design parameters are chosen to evaluate their effect on the cost of power:

1. wellbore completion method,

2. production string diameter, and

3. desired water temperature at the plant inlet.

The common data, in addition to the basic data and assumptions presented earlier, used for making the first series of calculations to assess the effect of design parameters are shown below:

1. flow rate per well = 53,000 pounds/hour,

2. pressure gradient = 0.5 psi/foot,

3. reservoir flow characteristic factor, "w" = 0.3 darcy-feet,

4. maximum allowed water velocity in the flow string = 1.0 feet/second,

5. maximum allowed temperature drop in the surface pipeline = 5.0 ^{o}F,

6. required water temperature at the plant inlet = 400 ^{o}F,

7. desired rate of return = 10 percent.

For each design parameter, the full range of the temperature gradients selected for this study, 2.0 to 5.0 ^{o}F per 100 feet, is studied.

Wellbore Completion Method

Two wellbore completion methods were considered. The mathematical model for each type of wellbore was described above. The annular wellbore completion method, with air filled or insulated annulus, offers an advantage in that the temperature loss from water to the surrounding formation is less, hence, shallower wellbores would seem satisfactory to meet the temperature requirements at the plant inlet. Thus, on one hand, the annular wellbore completion tends to reduce the cost of power by reducing the drilling and equipment expenses, while on the other hand, it tends to add to the cost be requiring two wellbore strings, and tubing as well as casing. In the case of non-annular wellbore completion, the advantage is that only one wellbore string is required, however, the savings are somewhat offset by the additional cost of deeper boreholes which are necessary to meet the same plant temperature requirement. The net effect of the advantages and disadvantages will result in either a higher or a lower cost of power for a particular wellbore completion method, assuming all other conditions are the same.

The results of the calculations are shown in Figure 7. It shows the effect of the borehole completion technique on the cost of power for various geothermal gradients. The cost varies from a minimum of 1.7 cents per KWH to over 4 cents per KWH. The minimum cost occurs for a non-annular wellbore completion when the temperature gradient is 5.0^{o}F per 100 feet. The highest cost occurs in the case of air-filled annular completion for a geothermal gradient of 2.0^{o}F per 100 feet. As it is shown in Figure 7, the cost of power is always lower for the non-annular wellbore completion. In this case, the range of cost is between 2.7 cents per KWH to 1.7 cents per KWH. The highest cost occurs at the lowest temperature gradient while the lowest one occurs at the highest temperature gradient. There is a sudden decrease in the cost, from 2.7 cents to 2.1 cents per KWH, when the geothermal

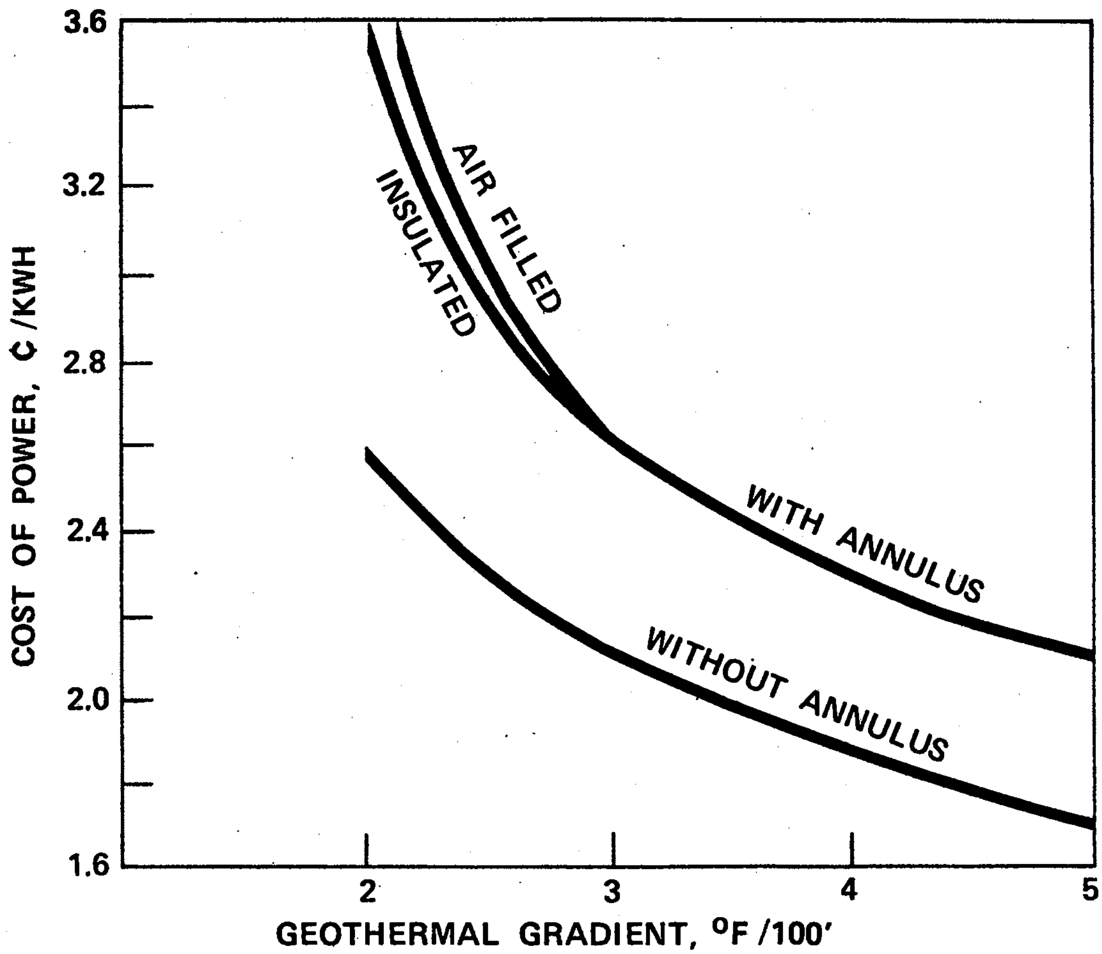

Figure 7, The Effect of Borehole Completion Technique on the Cost of Power for Various Geothermal Gradients gradient increases from 2.0 to 3.0 $^{\circ}$F per 100 feet. However, following the initial sudden decrease in cost, the subsequent changes are almost linear with the temperature gradient.

It was mentioned earlier that in the case of non-annular completion the temperature loss in the wellbore is higher and hence deeper boreholes are required to satisfy the temperature demand at the plant inlet. Calculations show that when the temperature gradient is 2 $^{\circ}$F, the temperature of hot water lowered approximately 92 $^{\circ}$F in the wellbore for non-annular completion as compared to only 19 $^{\circ}$F for annular completion with insulated annulus. Accordingly, the necessary wellbore depth varied from 21,150 feet in the former case to 17,466 feet in the latter case.

Table XI summarizes the calculated cost of power for the two types of wellbore completions as a function of geothermal gradient. The main difference in cost occurs due to the change in drilling and completion of production and exploratory wells. A comparison of these expenditures is shown in Table XII. The cost of power is consistantly less for the non-annular wellbore completions, even though the amount of power consumed by the pumps increased by about six percent, from 19 percent of the total produced in the case of annular wellbore completion with insulation to almost 25 percent in this case.

A breakdown of the total costs of developing geothermal power using non-annular wellbore completions for various geothermal gradients is shown in Table XIII. Initial project costs vary from about 5.1

TABLE XI

COST OF POWER FOR TWO WELLBORE COMPLETION TECHNIQUES AS A FUNCTION OF GEOTHERMAL GRADIENTS, ¢ PER KWH

Geothermal Gradient °F/100 feet	Annular Wellbore Completion		Non-Annular Wellbore Completion
	Air-Filled Annulus	Insulated Annulus	
2.0	4.0	3.6	2.7
3.0	2.9	2.9	2.1
4.0	2.7	2.7	1.9
5.0	2.5	2.5	1.7

TABLE XII

COST COMPARISON OF DRILLING AND COMPLETION OF TWELVE PRODUCTION WELLS AND TWO EXPLORATORY WELLS IN 10^3 DOLLARS FOR VARIOUS GEOTHERMAL GRADIENTS

Temperature Gradient	Annular Wellbore Completion		Non-Annular Wellbore Completion
$^{\circ}F$/100 feet	Without Insulation	With Insulation	
2.0	11,600.0	10,600.0	6,144.0
3.0	4,605.0	4,595.0	2,683.0
4.0	3,006.0	3,001.0	1,691.0
5.0	2,106.0	2,103.0	1,203.0

TABLE XIII

BREAKDOWN OF THE COSTS ASSOCIATED WITH THE GEOTHERMAL POWER DEVELOPMENT PROJECT, IN 10^3 DOLLARS FOR A 10 MW POWER PLANT

Cost Item	Temperature Gradient, °F/100 feet			
	2.0	3.0	4.0	5.0
Land Cost				
Lease Bonus	3.5	3.5	3.5	3.5
Lease Rent	2.8	2.8	2.8	2.8
Lease Royalty	312.0	312.0	312.0	312.0
Subtotal	328.3	328.3	328.3	328.3
Exploration Cost (Not including Exploratory Drilling)				
"Capitalized" Expenditures	35.0	35.0	35.0	35.0
"Expensed" Expenditures	70.0	70.0	70.0	70.0
Subtotal	105.0	105.0	105.0	105.0
Drilling and Wellbore Completions (Including Exploratory Drilling)				
"Intangible" Expenses	3666.0	1351.8	852.2	620.7
Casing	2477.0	1332.4	838.7	581.6
Submergible Pumps (Including Installment)	651.0	672.0	714.0	714.0
Wellhead Equipment	50.0	50.0	50.0	50.0
Subtotal	7874.0	3416.2	2454.9	1976.3
Surface Facilities				
Piping	82.1	82.1	82.1	82.1
Insulation	142.0	142.0	142.0	142.0
Subtotal	224.1	224.1	224.1	224.1
Power Plant				
Installment	2300.0	2300.0	2300.0	2300.0
Subtotal	2300.0	2300.0	2300.0	2300.0

TABLE XIII (Continued)

Cost Item	Temperature Gradient, ^{o}F/100 feet			
	2.0	3.0	4.0	5.0
Injection System				
Piping	23.4	23.4	23.4	23.4
"Intangible" Drilling	78.4	78.4	78.4	78.4
Wellbore Equipment	69.6	69.6	69.6	69.6
Subtotal	171.4	171.4	171.4	171.4
Project Total	11,002.8	6545.0	5583.7	5105.1
Operation and Maintenance (Total for Life of 20 Years)	2185.0	2185.0	2185.0	2185.0
Net Power Cost, Dollars/KWH	.0270	.0210	.0190	.0170

million dollars for a gradient of 5.0°F per 100 feet to a little over 11 million dollars for a 2.0°F per 100 feet gradient. Drilling and wellbore completion costs amounted to about 40 percent of the total initial cost in the former case while they amounted to about 70 percent in the latter case. This happens due to the exponential type relationship between the cost of drilling and equipment and the depth of a wellbore.

A discounted cash flow method is used in arriving at the cost of power for a desired rate of return, which is 10 percent in this case. An example of the cash flow calculations for a temperature gradient of 2.0°F per 100 feet is shown in Table XIV. All the cost calculations are performed in a similar manner.

Since it is observed that the non-annular wellbore completion yields a lower cost of power for the full range of temperature gradients, it is chosen as the best technique for geothermal wellbore completion. In all the following calculations, therefore, this completion method is used and the effect of other variables on the cost of power is evaluated.

Water Flow-String Diameter

Geothermal water from the reservoir is pumped to the power plant through the casing and surface pipeline. Choice of diameters of both flow strings has both a direct and an indirect effect on the cost of power. Smaller diameter flow strings tend to reduce the cost since they are less expensive and also reduce the heat loss, thus requiring relatively shallower boreholes. However, at the same time, more

TABLE XIV

EXAMPLE OF THE CASH FLOW CALCULATIONS*

Year	Gross Income	Capitalized Expenses	Borrowed Money	Principal Paid	Interest Paid	Expenses	Depreciation	Taxes	Cash Flow
1	0.0	431.4	280.4	0.0	28.0	703.3	0.0	-365.7	-516.7
2	0.0	1583.5	1029.3	0.0	131.0	1124.4	18.7	-637.0	-1172.6
3	0.0	1583.5	1029.3	0.0	233.9	1124.4	90.2	-734.3	-1188.3
4	0.0	1870.5	1215.8	0.0	355.5	1177.3	165.2	-849.0	-1338.5
5	1707.1	0.0	0.0	710.9	284.4	131.4	272.4	509.5	70.8
6	1707.1	0.0	0.0	710.9	213.3	131.4	272.4	545.0	106.4
7	1707.1	0.0	0.0	710.9	142.2	131.4	272.4	580.5	142.0
8	1707.1	0.0	0.0	710.9	71.1	131.4	272.4	616.1	177.0
9	1707.1	0.0	0.0	710.9	0.0	131.4	272.4	651.6	213.1
10	1707.1	0.0	0.0	0.0	0.0	131.4	272.4	651.6	924.0
11	1707.1	0.0	0.0	0.0	0.0	131.4	272.4	651.6	924.0
12	1707.1	0.0	0.0	0.0	0.0	131.4	272.4	651.6	924.0
13	1707.1	0.0	0.0	0.0	0.0	131.4	272.4	651.6	924.0
14	1707.1	71.8	0.0	0.0	0.0	144.6	272.4	645.0	845.7
15	1707.1	71.8	0.0	0.0	0.0	144.6	279.6	641.4	849.3
16	1707.1	71.8	0.0	0.0	0.0	144.6	286.7	637.9	852.9
17	1707.1	71.8	0.0	0.0	0.0	144.6	293.9	634.3	856.4
18	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
19	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
20	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
21	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
22	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
23	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4
24	1707.1	0.0	0.0	0.0	0.0	131.4	301.1	637.3	938.4

* All Numbers in Thousands of Dollars

power is required to pump the water through the smaller diameter flow strings. The objective here is neither to minimize the heat loss nor to minimize the power consumption of the pumps but instead it is to choose the flow string diameter that minimizes the cost of power.

One way the selection of a flow string may be made is by choosing the approximate water velocity. For example, in the previous calculations a water velocity of approximately 1.0 feet per second was specified as the maximum allowable velocity. A selection of the casing is made starting with the smallest diameter that satisfies the setting depth requirement. The diameter is then gradually increased until the velocity of water is equal to or less than the maximum allowed. In this way, assurance is made that both requirements, i.e. setting depth and the minimum velocity, are met with the smallest possible flow string. By selecting a range of the maximum allowed water velocities in the flow strings, the cost of power is evaluated for each combination of casing and surface pipe which satisfies the velocity requirements.

The maximum allowed velocity was changed from 0.5 feet per second to 2.5 feet per second, keeping the remaining data the same as before. The four combinations of casing diameter and surface pipe which yielded the water velocites in the range chosen were then used in the design and the cost of power was calculated for each temperature gradient. Results of the calculations are shown in Table XV. As it may be observed from the results, initially the cost of power decreases as the flow string diameter increases, however, as the diameter

TABLE XV

EFFECT OF CASING AND SURFACE PIPE DIAMETER ON THE COST OF POWER

Temperature Gradient, °F/100 feet	Casing O.D., inches	Nominal Diameter of the Surface Pipe, inches	Cost of Power, cents/KWH
2.0	10.750	8.0	3.90
	7.625	6.0	2.70
	6.625	5.0	2.90
	5.500	4.0	3.70
3.0	10.750	8.0	2.30
	7.625	6.0	2.10
	6.625	5.0	2.30
	5.500	4.0	2.50
4.0	10.750	8.0	2.10
	7.625	6.0	1.90
	6.625	5.0	2.10
	5.500	4.0	2.30
5.0	10.750	8.0	1.90
	7.625	6.0	1.70
	6.625	5.0	1.90
	5.500	4.0	2.10

increases beyond a certain level the cost of power begins to increase quite rapidly. The initial decrease comes mainly due to the reduction in power consumption by the pumps. For example, the fraction of the gross electric power consumed by the pumps changes from approximately 0.65 to about 0.20 when the temperature gradient is 2.0°F per 100 feet and the casing diameter changes from 5.500 inches O.D. to 7.625 inches O.D. Beyond this diameter, while the power comsumption remains about the same, the cost of drilling and completing the production wells increases by approximately 50 percent, resulting in a substantial increase in the cost of power.

For the assumed set of conditions, the minimum cost occurs, for all temperature gradients, when the water velocity is slightly less than 1.0 feet per second. The cost of power varies from a minimum of 1.70 cents to 3.90 cents per KWH. This is an increase of over 100 percent. Even for a given temperature gradient the cost may increase as much as 15 to 30 percent if the casing and surface pipe diameter are not properly chosen.

Water velocity is a function of the pipe diameter and the wellbore productivity. Therefore, for each wellbore productivity it is possible to have different water velocities which will yield the minimum cost of power. At the same time, wellbore productivity itself affects the cost since the number of production wells is inversely proportional to the wellbore productivity.

The effect of the wellbore productivity on the cost of power is shown in Figure 8. Wellbore productivity was changed from 26, 000 pounds per hour to 53, 000 pounds per hour. Calculations were made for the full range of the temperature gradients under consideration. For each wellbore productivity, water velocity yielding the minimum cost of power was determined by the procedure outlined earlier. As the wellbore productivity decreases, the velocity, resulting in minimum cost, increases. For example, for wellbore productivities of 26, 000, 37, 500 and 53, 000 pounds per hour, the water velocities giving the minimum cost changed from approximately 2. 00 feet per second to 1. 00 feet per second.

The effect of wellbore productivity on the cost of power is significant, and it increases as the temperature gradient decreases, especially for the wellbore productivities of lower than 35, 000 pounds per hour. This may be observed in Figure 8. For example, in the case where the temperature gradient is 3. 00°F per 100 feet, the cost of power increases from 2. 1 cents to 2. 25 cents per KWH if the wellbore productivity decreases from 53, 000 to 40, 000 pounds per hour. However, for the same decrease of 13, 000 pounds per hour, the cost increases from 2. 25 cents to 3. 25 cents per KWH if the productivity decreases from 40, 000 pounds to 27, 000 pounds per hour. The range of cost varies from 1. 7 cents to 3. 3 cents per KWH. For the temperature gradient of 2. 0°F per 100 feet, the bottom-hole temperature exceeded 500°F for the wellbore productivities of 26, 000 pounds per hour and hence this situation is considered unfeasible due to the

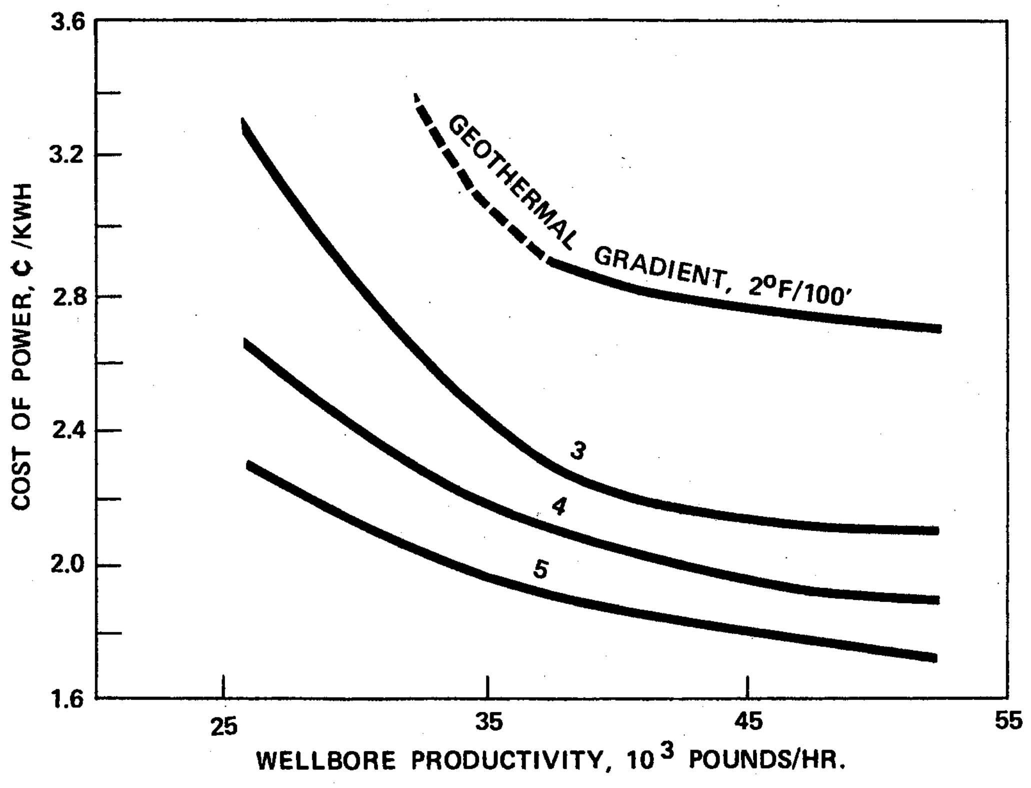

Figure 8. The Effect of Geothermal Gradients on the Cost of Power for Various Wellbore Productivities

temperature limitations for the submergible pump.

When an effort was made to reduce the temperature loss in the wellbore by reducing the casing diameter, the power consumption of the pumps exceeded the amount of power generated, hence making the entire project a total failure. Therefore, in Figure 8 the curve for wellbore productivity less than 37,500 pounds per hour is shown dotted for the temperature gradient of 2.0°F per 100 feet. Table XVI shows the calculated values of cost of power for three different wellbore productivities and for the full range of the geothermal gradients.

In selecting the wellbore completion design and the diameter of the flow string, the value of the third design variable, namely the required hot water temperature at the power plant inlet, was assumed to be 400°F. Choice of the temperature at the plant inlet has an effect on the cost of power due to several reasons and hence, this design variable is studied next.

Desired Water Temperature at the Plant Inlet

From the point of view of conversion efficiency at the power plant, it is certainly desirable to have the highest possible temperature of water at the heat-exchanger inlet to the power plant. From the point of view of the cost, higher conversion efficiency means a smaller number of production wells and hence a smaller amount of associated expenditures. However, at the same time, higher temperature is achieved by drilling deeper and results in more expensive boreholes.

TABLE XVI

EFFECT OF WELLBORE PRODUCTIVITIES ON THE COST OF POWER FOR VARIOUS TEMPERATURE GRADIENTS

Temperature Gradient, °F per 100 feet	Cost of Power, Cents per KWH — Wellbore Productivities, Pounds per Hour		
	26,000	37,500	53,000
2.0	--	2.9	2.7
3.0	3.3	2.3	2.1
4.0	2.7	2.1	1.9
5.0	2.3	1.9	1.7

Deeper wells also need more power to lift water to the surface and thus tend to reduce the amount of power available for sale. The two latter situations would tend to increase the cost of power and hence it is desirable to evaluate the net effect of these somewhat offsetting tendencies.

Four levels of temperatures at the plant inlet were selected to determine the cost of power for wells producing 53,000 pounds per hour each. The range of temperatures varied from $325^{\circ}F$ to $450^{\circ}F$. Anytime the bottom-hole temperature exceeded $500^{\circ}F$, that particular situation was considered infeasible. The results of the calculations are shown in Table XVII and Figure 9. Initially, as the temperature increases from $325^{\circ}F$ to about $350^{\circ}F$, the cost of power decreases drastically. For example, the cost changes from about 3.5 cents to 2.0 cents per KWH with the corresponding change of $325^{\circ}F$ to $360^{\circ}F$ temperature at the plant inlet for a temperature gradient of $5.0^{\circ}F$ per 100 feet. Similar decreases occur for all the temperature gradients. When the temperature gradient is $2.0^{\circ}F$ per 100 feet, the infeasible situation develops in that the minimum bottom-hole temperature exceeds the $500^{\circ}F$ limit.

The initial drastic change in the cost of power occurs due to many reasons. First of all, as the temperature of water at the plant inlet increases, the flow rate required to produce the same amount of power decreases. As it is shown in Figure 4, for the chosen plant design and conditions, this decrease is much greater until the temperature

TABLE XVII

THE EFFECT OF REQUIRED POWER PLANT INLET TEMPERATURE ON THE COST OF POWER FOR VARIOUS TEMPERATURE GRADIENTS

Required Power Plant Inlet Temperature, °F	Cost of Power, ¢/KWH			
	Temperature Gradient, °F/100 feet			
	2.0	3.0	4.0	5.0
325	4.7	3.9	3.7	3.5
350	3.3	2.4	2.2	2.0
400	2.7	2.1	1.9	1.7
450	--	1.9	1.7	1.5

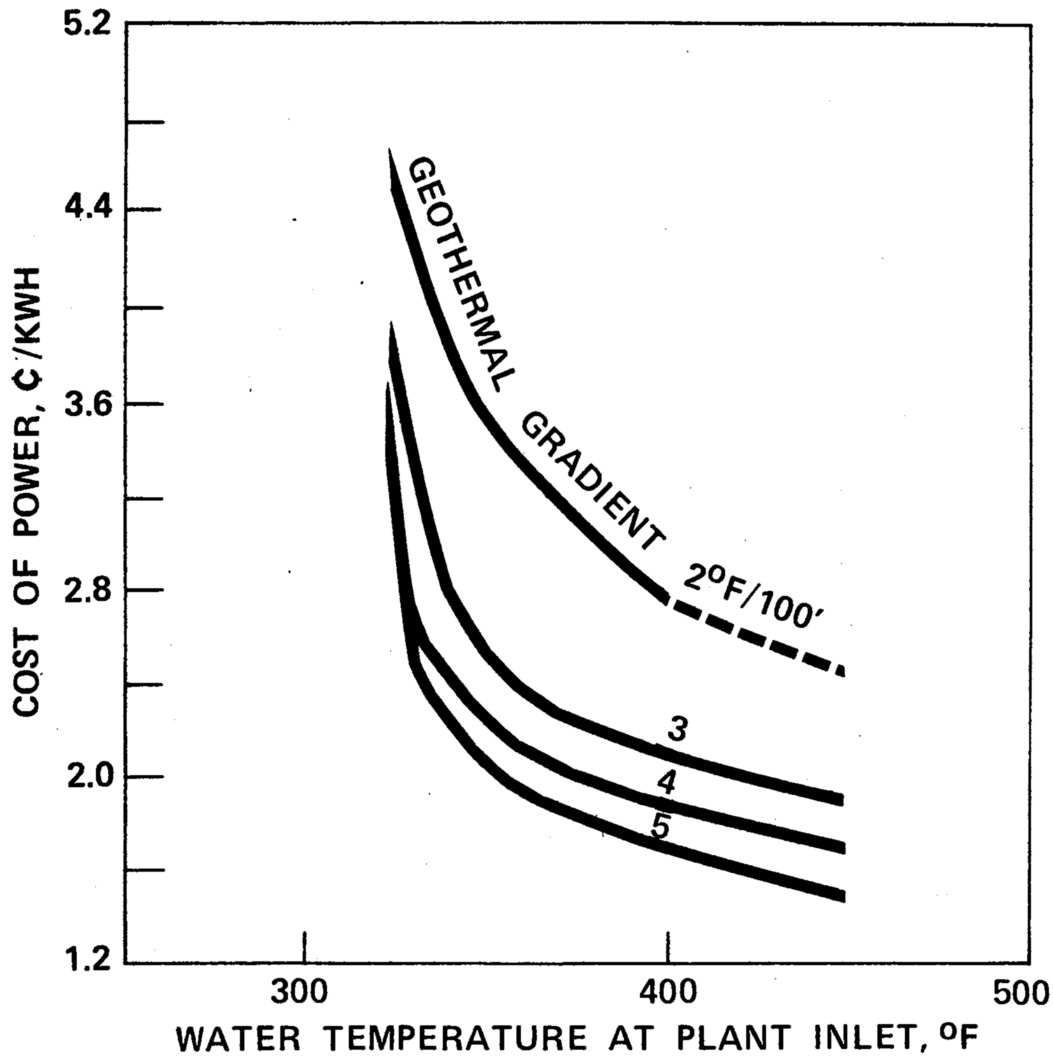

Figure 9. The Effect of Geothermal Gradients on the Cost of Power for Various Power Plant Inlet Water Temperatures

falls to around 350-360°F. Beyond that, even though the decrease is still logarithmic, the rate of decrease is much smaller and hence it does not affect the flow rate in the same proportion. With the reduced water flow rate requirements, the number of production and injection wells in reduced proportionately.

Similar to the water requirements, the rate of change of cost with temperature is extremely high around 325°F. If the temperature required at the power plant is reduced to slightly lower than 325°F for the chosen system, the cost of power would increase substantially, as it may be observed from Figure 9. However, cost reduction beyond 350°F is almost linear up to 450°F. Beyond this temperature range, equipment limitations will not allow a feasible design for the production of hot water used to generate electricity.

In summary, the effect of three design variables on the cost of geothermal power was studied. The non-annular wellbore completion method yielded lower costs than the annular method for all the cases studied here. This implies that while the actual temperature loss for the former case was greater, in terms of economic advantage, the cost of saving the amount of lost energy is higher than the cost of energy itself. Next, taking the non-annular wellbore as a selected design, the effect of the flow string diameter on the cost was studied. The diameter affects the temperature loss as well as the horsepower required to lift and transport water to the power plant. It appeared that each one affected the cost to a varying degree, depending on the actual diameter chosen. For a given set of conditions, an optimum diameter exists where the cost of power is at a minimum. Selecting the optimum diameter for each case, the effect of power plant design, expressed in terms of the required water temperature at the plant inlet, was studied. In this case the marked decrease in cost with a slight increase in temperature is noteworthy, especially at the lower end of the temperature range. Since at 400°F it is feasible to design the production system for all temperature gradients under consideration, this temperature is chosen for the power plant design.

The cost of power is not only affected by the selection of equipment or design variables but it is also affected by the natural surroundings existing in the area. The primary variables of importance are the geothermal gradient, pressure gradient, and the reservoir flow characteristics. In the calculations for the study, the effect of geothermal gradients is studied in all cases. The effect of the remaining two natural surroundings is also evaluated.

Effect of Natural Surroundings on the Cost of Power

The geothermal reservoir system is characterized by many naturally occurring conditions such as temperature and pressure gradients, reservoir rock porosity and permeability, reservoir size and shape, etc. These and some other characteristics influence the cost of power for various reasons. For example, the temperature gradient dictates the depth of production wells and hence determines the cost of development. The pressure gradient influences the reservoir pressure and also the maximum wellbore productivity. These two conditions help determine the size of the submergible pump and also the number of wells required to support a given sized power plant. Similarly, properties of the reservoir rock determine the amount of available hot water and the pressure at the bottom of the wellbore. In general, then, natural surroundings affect the cost directly, or indirectly, due to a change in the equipment selection.

In addition to the effect of geothermal gradients on the cost which has been studied in all cases, the effects of pressure gradients and reservoir flow characteristics have also been studied. These two characteristics of naturally occurring surroundings are chosen since they influence the equipment selection for the hot water production system which is the one main concern of this dissertation. The basic set of data assumed for all the calculations under the heading are:

1. water flow rate per well = 53,000 pounds/hour,
2. pressure gradient = specified or 0.5 psi/foot if unspecified,
3. reservoir flow characteristic factor, "w" = specified or 0.3 darcy-feet if unspecified,
4. maximum allowed water velocity in the flow string = 1.0 feet/second,
5. maximum allowed temperature drop in the surface pipeline = 5.0°F,

6. required water temperature at the power plant inlet = $400^{o}F$,

7. desired rate of return = 10 percent.

Effect of Pressure Gradient

Similar to the temperature gradient, a pressure gradient also exists in all locations. It is usually between 0.433 psi per foot, resulting from the hydrostatic head of fresh water, and 0.5 psi per foot in the case of saline water. Since in most locations saline water is very common, in all the previous calculations a pressure gradient of 0.5 psi per foot was used. Assuming all other conditions are the same, an increased pressure gradient increases the bottom-hole flowing pressure, thus reducing the amount of energy required to lift and transport water from the bottom of the wellbore to the power plant. This reduction then causes a corresponding reduction in the submergible pump capacity and in its electric power consumption, resulting in the increased amount of power available for sale from a given system. In general then the higher pressure gradients will tend to reduce the unit cost of power by making more of it available for sale from a given operation. By the same token, it can also be expected that this benefit will not be indefinite because as the pressure gradient increases and reaches a point where water will lift itself (without any help from the pump), any additional increase in the pressure gradient will not reduce the cost of power.

A series of pressure gradient calculations were made and the results are presented in Figure 10 and Table XVIII. A substantial decrease in the cost occurs as the pressure gradient increases from 0.4 to 0.6 psi per foot. At a pressure gradient of 0.4 psi per foot the power consumed by the pumps amounts to over 48 percent of the total power produced while it reduces to less than 10 percent for the 0.6 psi per foot pressure gradient. Power consumption by the pumps reduces to zero when the pressure gradient reaches around 0.7 psi per foot.

As it may be observed from Figure 10, the cost of power reaches a minimum at this point and stays there even with the increased pressure gradient. Initially, between the gradient of 0.4 to 0.6 psi per foot the rate of decrease in cost is linear (or approximately linear for the geothermal gradient of 2°F per foot) with about the same slope for the higher temperature gradients. For the lower gradients the slope is much steeper. For example, for the temperature gradients of 4.0 and 5.0°F per 100 feet, the slope is about 3¢ per psi while it is 4¢ for the gradient of 3.0 and 14¢ for the temperature gradients of 2.0°F per 100 feet. These variations in slope occur, again, due to the variations in power consumption by the pumps. As the temperature gradient decreases, the wellbore depth increases, thus requiring additional pump capacity to lift the water. When the temperature gradient is 2.0°F per 100 feet and the pressure gradient is 0.4 psi per foot, the total power consumed by the pumps, in the system selected, amounts to a little over 75 percent of the total produced. The effect of the pressure gradients on the cost of power for various geothermal gradients is

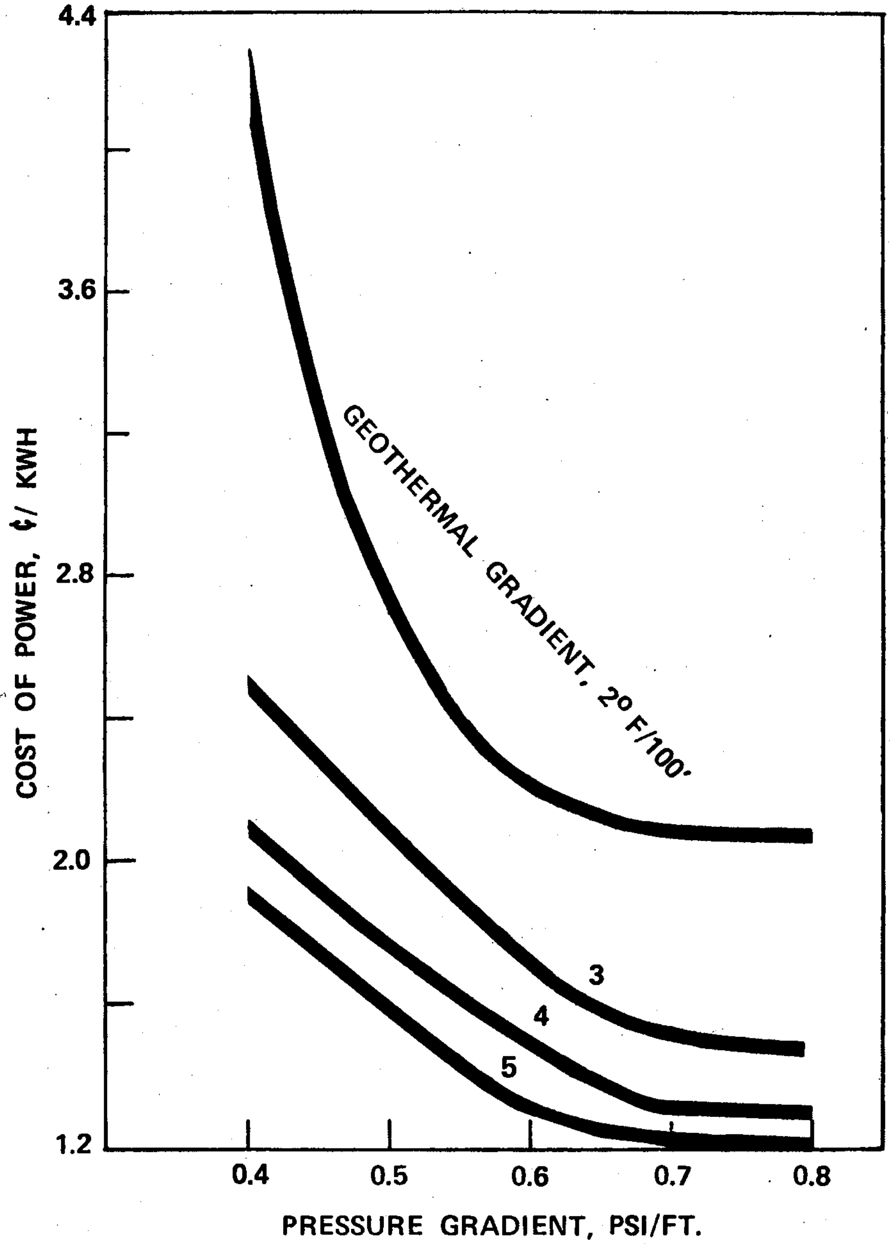

Figure 10. The Effect of Geothermal Gradients on the Cost of Power for Various Pressure Gradients

TABLE XVIII

THE EFFECT OF PRESSURE GRADIENTS ON THE COST OF POWER FOR VARIOUS PRESSURE GRADIENTS

Pressure Gradient, Psi/Ft.	Cost of Power, ¢/KWH			
	Temperature Gradient, ^{o}F/100 feet			
	2.0	3.0	4.0	5.0
0.4	4.3	2.5	2.1	1.9
0.5	2.7	2.1	1.9	1.7
0.6	2.2	1.7	1.5	1.3
0.7	2.1	1.5	1.3	1.2
0.8	2.1	1.5	1.3	1.2

tabulated in Table XVIII.

The effect of pressure gradient on the cost is of particular significance since there are areas (referred to as "geopressure zones") where the pressure gradients are higher than 0.5 psi per foot. As can be observed from the calculations, in some cases the cost of power can be reduced to less than half, even if the pressure gradient is higher than normal by only 0.2 psi per foot. Thus, the relative advantage that can be gained in exploring geopressure zones for power generation is obvious.

Effect of Reservoir Flow Characteristic, "w"

The reservoir flow characteristic, "w", as defined earlier has a qualitiative effect similar to that of the pressure gradient. Higher values of "w" mean less resistance to the flow of water from the reservoir into the wellbore. This results in higher flowing pressure, assuming all other conditions are the same. As mentioned before, higher flowing pressure at the bottom of the wellbore is desirable since less electricity is consumed in pumping. Similar to the effect of the pressure gradients, beyond a certain value of "w" this advantage disappears, since the increase in the bottom-hole flowing pressure beyond that point is almost insignificant.

Results of a series of calculations made, with the pressure gradient of 0.5 psi per foot, are presented in Figure 11. This figure shows the effect of geothermal gradients on the cost of power for various

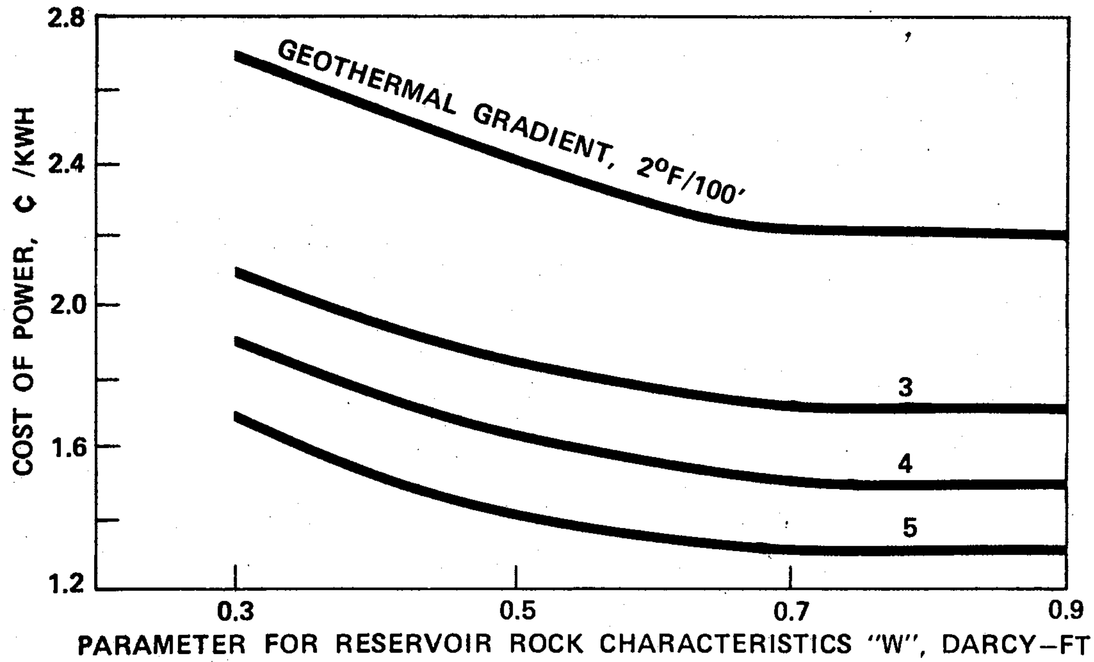

Figure 11, The Effect of Geothermal Gradients on the Cost of Power for Various Reservoir Rock Characteristics values of the reservoir rock characteristic, "w". The range of "w" varies from 0.3 to 0.9 darcy-feet. The cost of power decreases rapidly between the values of 0.3 to 0.7 darcy-feet, however, beyond the value of 0.7 the cost remains the same for all the values of "w". This situation occurs for all the geothermal gradients studied. Unlike the effect of pressure gradients, the effect of the reservoir flow characteristic is not nearly as dramatic, especially at lower temperature gradients. Also, the lowest cost reached in this case (at "w" = 0.7 darcy-feet) is still higher than the lowest achieved in the pressure gradient case by 0.1¢ to 0.2¢ per KWH. These circumstances occur since even at "w" = 0.7 darcy-feet, some energy must be expended to lift water from the bottom of the wellbore to the power plant. This is to overcome the frictional pressure losses in the wellbore and the pipeline.

At the lowest cost condition, approximately 8-13 percent of the power is consumed in pumping. A tabulation of the results is shown in Table XIX. The effect of the reservoir rock flow characteristics on the cost of power is significant and the range of advantage that high permeability reservoirs or "fractured" reservoirs offer could be a deciding factor in the geothermal power operation.

In addition to the effect of design variables and naturally existing surroundings, the cost of geothermal power is also influenced by the data used in cost estimating and the assumptions made for the economic model. It is virtually impossible to vary all data and assumptions to

TABLE XIX

THE EFFECT OF THE RESERVOIR ROCK FLOW CHARACTERISTIC "w" ON THE COST OF POWER FOR VARIOUS GEOTHERMAL GRADIENTS

Reservoir Rock Flow Characteristic, "w", darcy-feet	Cost of Power, ¢/KWH			
	Geothermal Gradient, °F/100 Feet			
	2.0	3.0	4.0	5.0
0.3	2.7	2.1	1.9	1.7
0.5	2.4	1.8	1.6	1.4
0.7	2.3	1.7	1.5	1.3
0.9	2.3	1.7	1.5	1.3

evaluate the individual effect. However, results of two different calculations are shown here.

Effect of Cost Data and Economic Assumptions

Two calculations are made to indicate the range of variation in cost due to changes in the cost data and the economic conditions. In all the previous calculations, the cost of the power plant was assumed to be \$230.00 per kilowatt installed. While this is based on the best available data, since there is no plant of the proposed design in existence, it is likely that this cost could vary significantly. Also, the power plant cost is a big component in the total development cost. Therefore, the cost of power is evaluated for various unit costs of the power plant starting with \$180 to \$310 per kilowatt installed, with the increment of \$50.

The effect of the power plant cost on the cost of power for various geothermal gradients is shown in Figure 12. The cost of power varies linearly with almost the same slope for all the geothermal gradients. For each increment of \$50 per kilowatt in the cost of the power plant there is a corresponding increase of 0.2 cents per KWH for the system chosen. This is based on the desired rate of return of 10 percent. In all previous calculations this rate was assumed. Obviously, the desired rate of return would change from investor to investor and would also change with the changing economic conditions.

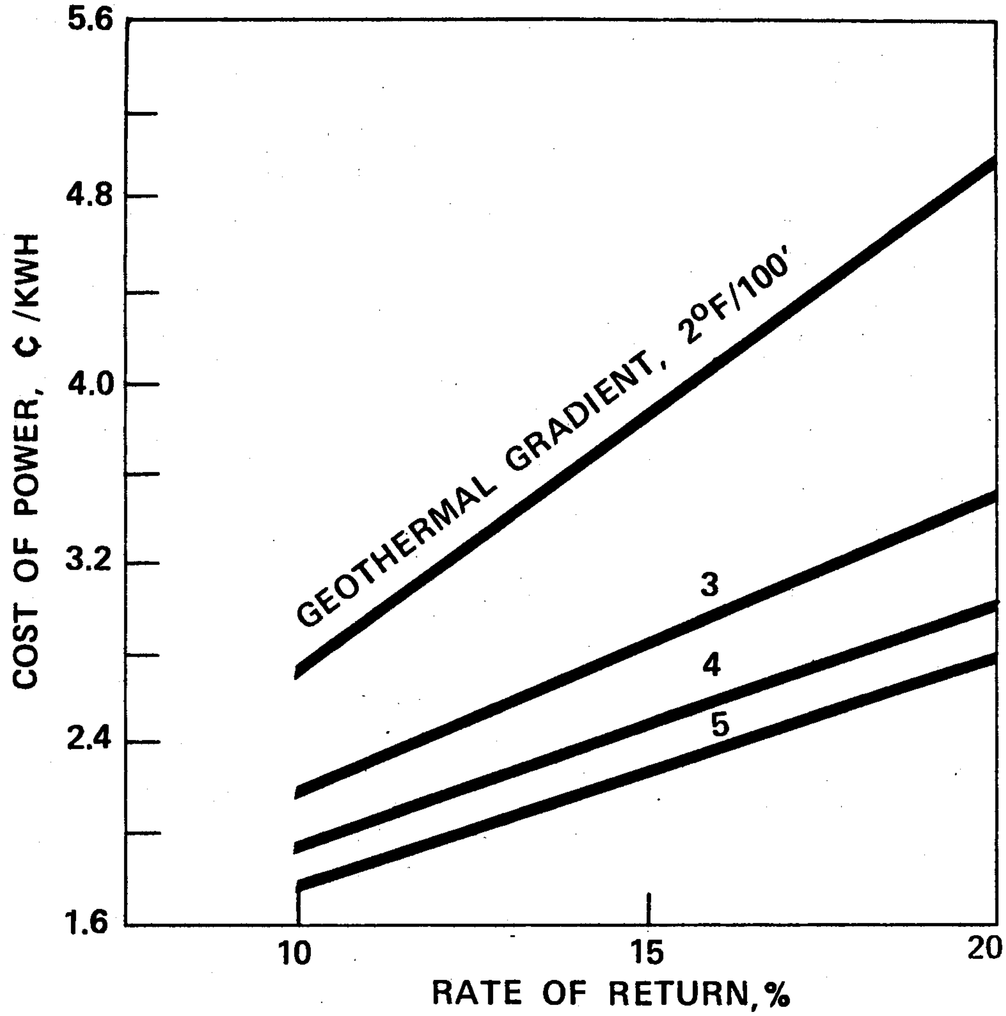

Figure 12. The Effect of Geothermal Gradients on the Cost of Power for Various Required Rates of Return

To evaluate the effect of different desired rates of return, the cost calculations were made assuming 15 and 20 percent as the desired rates of return. As indicated in Figure 13, the cost variations are also linear in this case; however, the slope of each line in the graph is different for each geothermal gradient. For the lowest gradient, i. e. 2. 0°F per 100 feet, the variation is the largest while for the 5. 0°F gradient it is the smallest. For each 5 percent increase in the desired rate of return, the cost of power increases by 1. 2 cents per KWH in the former case while with the same change in the desired rate of return the corresponding change in the cost is only 0. 6 cents per KWH in the latter case.

According to the objective of this dissertation, basically three things have been studied. In the first place, a range of cost of geothermal power is assessed and then the variation in cost due to the design variables and changing natural surroundings is determined. The parameters and their ranges studied in this dissertation are shown below:

	Parameter	Range Studied
1.	Geothermal Gradient, °F/100 Ft.	2-5
2.	Wellbore Productivity, #/Hr.	25000-55000
3.	Water Velocity in Casing, Ft. /Sec.	0. 5-2. 5
4.	Nominal Surface Pipe Diameter, Inches	2-8
5.	Temperature at the Plant Inlet, °F	325-450
6.	Pressure Gradient, Psi/Ft.	0. 4-0. 8

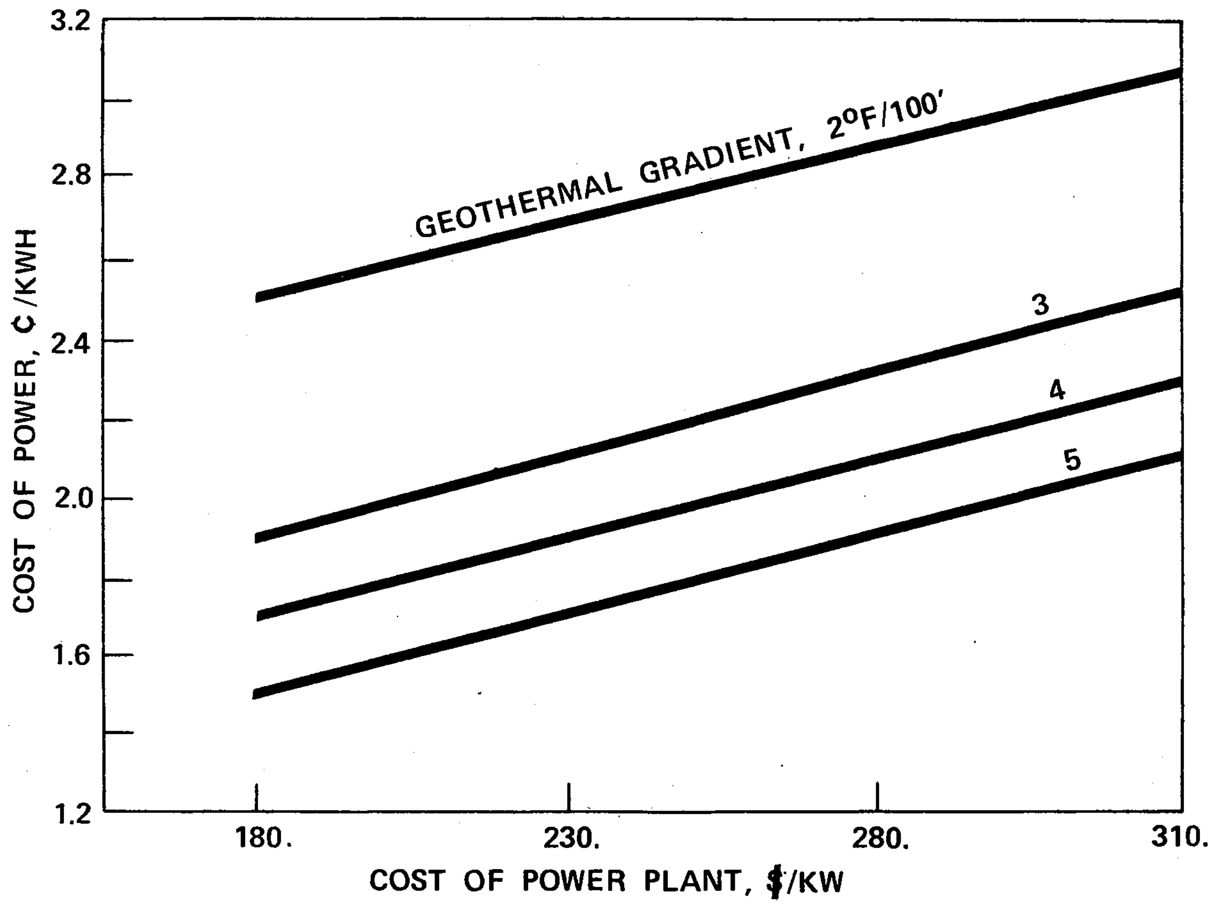

Figure 13. The Effect of Geothermal Gradients on the Cost of Power for Various Power Plant Costs

7.	Reservoir Rock Flow Characteristics, "w", Darcy-Ft.	0.3-0.9
8.	Desired Rate of Return, %	10-20

Epilogue

There is basically one primary prerequisite for any energy resource to become commercially exploitable, and that is for it to be economically competitive with other energy resources. Hence, the unit cost of producing and utilizing the energy resource is the most sought after result of any study. At this juncture in the energy history of the United States, it is quite likely, due to a number of technological, economic, environmental, and societal circumstances, that "new" sources of energy will enter the energy market. The situation is particularly and immediately true in the case of energy resources that can be conveniently coverted to electricity. Therefore, the need for evaluation of the economic potential of any "new" source is beyond question. Furthermore, in evaluating these "new" energy resources, it is most important to obtain the "range" of its cost rather than the actual cost itself, since the latter is much more time consuming and expensive. If the "range" of cost appears attractive for further consideration, that particular resource can be further examined in detail. With this in mind, the present research was undertaken and conducted, and it is hoped that the data, calculations and the results of this study are interpreted in that light.

The exploitation of "low" grade geothermal resources is a vast new area with a number of technological challenges. It is practically impossible for one study to tackle even a few problems in complete detail, much less all of them. No attempt was made, in the present study, to solve any particular problem in geothermal energy exploitation, but rather to arrive at the range of cost of producing geothermal power with due considerations to the basic technology and associated economics. Some of the basic technological variables were discussed and the effect of their choice on the cost of power was shown. Also, the effect of some of the primary variables associated with a geographical location were studied. These two aspects appear to be the more significant considerations in the initial phase of the development of this energy resource. In this sense the author hopes that this study will in time prove to be the catalyst that this energy resource needs for its universal acceptance.

Conclusions

1. This study has established the range of cost of producing power from geothermal waters under a variety of conditions. The calculated cost of geothermal power, depending upon the design and naturally occurring conditions, varied from 1.23 cents per KWH to 4.95 cents per KWH. This range of cost is higher than the present day average cost of power, however, the cost of power from small (less than 50 MW) nuclear plants is substantially higher than the present day

average and is projected to increase substantially in the future (36). Under these circumstances, it appears that low grade geothermal energy could be a practical source of power.

2. The cost of geothermal power is always lower, under the conditions studied, when the wellbores are completed without an annulus. The reduction in cost amounts to approximately 0.4 cents per KWH. The primary cause of such a reduction is that while the wellbore heat loss in the non-annular completion is larger than in the annular completion, requiring deeper and hence more expensive wells, the additional expense of an extra flow string and/or insulation is more than enough to offset the incremental expense incurred in drilling deeper wells.

3. There is an optimum in the casing and the surface pipe diameter which gives a minimum cost of power. While it is mainly a function of the flow rate, maintaining the water velocity in the range of 0.8 to 1.0 feet per second yielded the lowest cost. Deviation from this range increased the cost of power from anywhere between 0.2 cents to 1.2 cents per KWH. At lower geothermal gradients the deviation was significant as the velocity was reduced below this range.

4. The cost of power reduced drastically as the wellbore productivity increased from 25,000 to over 50,000 pounds per hour. The initial decrease in the cost, as the flow rate increases, is much higher and furthermore, at lower geothermal gradients the reduction in cost with increasing flow rate is dramatic. For example, when the gradient

was 3.0°F per 100 feet the difference in cost between the highest and the lowest flow rates was over 50 percent as against only 30 percent for the geothermal gradient of 5.0°F per 100 feet.

5. Perhaps the most significant decrease in cost occurred when the required hot water temperature was raised from 325°F to 400°F for the geothermal power system chosen. In all cases, the cost of power was reduced by anywhere between 80 to 100 percent. Even a temperature of 350°F caused significant reduction in the cost. Beyond 400°F, the decrease in cost was linear and since there is a danger of exceeding the temperature limit for the number of equipment components, it is felt that a temperature of about 400°F at the power plant should be an optimum for the system chosen.

6. In general, it was observed that for the three design variables studied, there is an optimum in each case which reduced the cost significantly, and the reduction was more pronounced with the lower geothermal gradients.

7. Similar to the design variables, naturally occurring conditions also have an effect on the cost of power. A change in the pressure gradient from 0.4 to 0.6 psi per foot reduced the cost of power by almost 100 percent for the gradient of 2.0°F or by 35 percent for the gradient of 5.0°F per 100 feet. Beyond the gradient of 0.6 psi per foot the change was small but noticable up to 0.7 psi per foot. However, beyond this value there is no more advantage gained by the increased pressure gradient for the flow rate of around 50,000 pounds per hour.

It appears that geopressure zones are promising for geothermal energy exploitation.

8. Reservoir rock flow characteristics, represented by "w" darcy-feet, reduces the cost almost linearly up to the value of 0.7 darcy-feet. The rate of decrease, which is about the same for all the geothermal gradients, is approximately 1.5 cents per KWH per unit change in "w" darcy-feet. Beyond the value of 0.7 darcy-feet the reduction in cost is not realized for the flow rate of about 50,000 pounds per hour.

9. Change in the cost of power due to the variation in the cost of the power plant is linear for all geothermal gradients. The rate of change is the same for all the gradients and is 0.2 cents per KWH per $50 change in the cost of the power plant.

10. Variation in the cost of power due to the different desired rates of return is also linear, however, the rate of change is unique for each geothermal gradient. The rate of change in cost is inversely proportional to the geothermal gradient. For example, it is the highest at 1.2 cents per KWH per 5 percent increase in the rate of return for 2.0°F gradient as against only 0.6 cents per KWH for the 5.0°F gradient.

Recommendations

1. Many assumptions were required in arriving at the numerical results of this study. These assumptions have been explicitly

mentioned whenever the occasion came. While in a study of this nature it is practically impossible to attempt all permutations and combinations of the possible natural, design and economic circumstances that may occur, it appears worthwhile to analyze the cost of geothermal power with the inclusion of the "element of risk" in the venture. This is particularly true in the exploration phase, since the present study has assumed 100 percent success in the exploration.

2. In arriving at the results of this study, no consideration was given to the "optimum" water withdrawal rates in relation to the size of the reservoir, the amount of heat flow in the reservoir or the possibility of soil subsidence in the area. The study of this aspect may be of significant value prior to the actual exploitation.

3. There was no effort made here to "optimize" the injection system especially the number and distribution of the waste water injection wells; this would appear to have an effect on the life and productivity of the reservoir. These two factors can affect the power cost considerably. This is another area that deserves full consideration.

4. The conversion system is one of the most important components in the success of a geothermal power venture. The fundamental principles and description of the power plant are presented in detail in this study. However, no consideration was given to alternate power cycles or the design systems that may be feasible. Research in this area is strongly recommended.

5. Other than power generation, there are a number of possible

uses of geothermal waters. The techno-economic evaluations of the multipurpose uses of geothermal energy could be a great contribution to its development.

6. The temperature limitations imposed on the use of submergible pumps restricts the exploitation of very high temperature waters, especially where the geothermal gradients are between 3°F to 5°F per 100 feet. Research in the improvement of this part of the equipment and others is also strongly recommended.

7. The problems associated with establishing applicable tax considerations and legal intricacies in the development of geothermal energy, especially the "low grade" energy, must certainly be solved before this resource can be exploited. The solutions may lie at the interface of various disciplines and should be undertaken accordingly.

8. It is obvious that the cost data used in this study is time dependent. As the prices of various items in the exploitation project change, the cost of power will be affected, in some cases quite considerably. Hence, it is recommended that this study be periodically updated.

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APPENDIX

A STEP-WISE CALCULATIONAL PROCEDURE

A step-wise procedure to evaluate the cost of power for a given set of natural surroundings, design parameters and economic conditions is outlined as follows:

STEP #	FUNCTION OF THE STEP	DETAILS OF THE FUNCTION	COMPUTER SYMBOL	UNITS	COMPUTER SUBROUTINE USED
1.	Specify Natural Surroundings	Geothermal Gradient	TEMGR	°F/100 feet	INPUT
		Pressure Gradient	PREGRA	Psi/foot	
		Reservoir Rock Flow Characteristic	PERTHI	Darcy-foot	
		Productivity Per Well	FLWPW	pounds/hour	
2.	Specify Power Plant Design	Power Plant Size	PPCAP	MW	INPUT
		Required Water Temperature and	WTPPI	°F	
		Flow Rate per KWH at Plant Inlet	WFLPPI	Pounds/KWH	
		Load Inlet	FLOAD	Decimal Fraction	
3.	Specify Gathering System Design	Well Spacing	NWS	Acres/Well	INPUT
		Diameter of Surface Pipe	SIZNSP	Inches	
		Insulation Thickness	DFWTPP	Inches	
		Ambient Temperature	TEMAB	°F	
4.	Specify Wellbore Design Parameters	Maximum Water Velocity Allowed in the Flow String	AVELWT	Feet/Second	INPUT
5.	Specify Injection System Design	Casing Diameter of the Well	DIAIJ	Inches	INPUT
		Depth of Injection Well	DEPINJ	Feet	
		Ratio of Production Well to the Injection Wells	WNOINJ		
		Diameter of the Waste Water Pipe	DIWWP	Inches	
6.	Specify Land Cost	Lease Bonus	EXLBON	$/Acre	INPUT
		Lease Rent	EXLREN	$/Acre/Yr.	
		Lease Royalty	EXROYL	$/#/Year	

STEP #	FUNCTION OF THE STEP	DETAILS OF THE FUNCTION	COMPUTER SYMBOL	UNITS	COMPUTER SUBROUTINE USED
7.	Specify Exploration Cost	Exploration Expense, "Expensed"	EXEXPL	$/Acre/Year	INPUT
		Exploration Expense, "Capitalized"	EXEXPC	$/Acre/Year	
8.	Specify Power Plant Cost	Power Plant Installation Cost	COVPMI	Dollars/KW	INPUT
9.	Specify Economic Conditions	Fraction of the Initial Tangible Capital Borrowed	FRMONB	Decimal Fraction	INPUT
		Interest on the Borrowed Money	RINTBM	Percent	
		Tax Rate	TAXRAT	Decimal Fraction	
		Number of Years Contracted to Return Borrowed Money	NYRRBM	Years	
10.	Specify Variables Related to a Particular Venture	Number of Years of Exploration	NYREXP	Years	INPUT
		Number of Years of Development	NYRDE	Years	
		Number of Exploratory Wells	NEXPDW	Wells/Year	
		Operation and Maintenance Cost	FOAMPP	Decimal Fraction	
		Desired Rate of Return	CS3	Percent	
		Number of Years of Productive Life	NYRLIF	Years	
11.	Initialize the Calculations	Size of the Depth Step	DELD	Feet	INPUT
		Size of the Added Depth	ADDEP	Feet	
12.	Calculate	Number of Wells Required	NOPW		WELLNO
		Total Land Required	TLAND	Acres	
		Average Distance from the Well to the Power Plant	DFWTPP	Feet	

STEP #	FUNCTION OF THE STEP	DETAILS OF THE FUNCTION	COMPUTER SYMBOL	UNITS	COMPUTER SUBROUTINE USED
13.	Calculate	Temperature Required at the Well-head	WTEMWH	^{o}F	SFACIL
		Pressure Drop in the Surface Pipeline	PDINP	$\#_f/\text{Feet}^2$	
14.	Calculate	Depth Required for Drilling	DEPMIN	Feet	DEPDES
		Diameter of Casing	RCO	Inches	
		Diameter of Hole	RHO	Inches	
		Wellhead Pressure Required	WHDP	$\#_f/\text{Feet}^2$	
		Bottom Hole Flowing Pressure	BHP	$\#_f/\text{Feet}^2$	
15.	Calculate	Temperature Profile of Water	TZTARS	^{o}F	ARSHTL
16.	Calculate	Pump Horse Power	HPPUMP	Horse Power	PUMPHP
		Power Used by Pumps	PUMPWR	KW	
17.	Write the Selected Design	All Design Variables that are Calculated in Steps 12 through 16			OUTPUT
18.	Calculate Yearly Cost of	Lease Bonus	TEXBN	\$/Year	EXPLND
		Lease Rental	TEXREN	\$/Year	
		Lease Royalty	TEXROY	\$/Year	
19.	Calculate Yearly Cost of	Exploration Cost, "Expensed"	TEXEXP	\$/Year	EXPEXP
		Exploration Cost, "Capitalized"	TEXEXC	\$/Year	
20.	Calculate	Yearly Intangible Drilling Expenses	TDRLEX	\$/Year	DEVELP

STEP #	FUNCTION OF THE STEP	DETAILS OF THE FUNCTION	COMPUTER SYMBOL	UNITS	COMPUTER SUBROUTINE USED
21.	Calculate Yearly Cost of	Casing	TTACC	$/Year	EQIPCS
		Pump, Equipment	PUMCAP	$/Year	
		Pump Installation	PUMEXC	$/Year	
22.	Calculate Yearly Cost of	Wellhead Equipment	CSTWHE	$/Year	SUREQP
		Surface Pipeline	SPCCST	$/Year	
		Surface Pipe Insulation	TCSTSI	$/Year	
23.	Calculate Yearly Cost of	Power Plant Installation	TCSTPP	$/Year	PWRPLC
		Operation and Maintenance	OMCSTP	$/Year	
24.	Calculate Yearly Cost of	Intangible Drilling Expenses	DRLEIN	$/Year	CSTINJ
		Casing	TDEXIN	$/Year	
		Waste Water Pipeline	CCWWP	$/Year	
25.	Calculate Yearly	"Capitalized" Expense	CAPEXP	$/Year	CASHFL
		"Expensed" Expense	YREPN		
		Depreciation	TDEPTN		
		Borrowed Money	BORMON		
		Principal Paid	PRINRN		
		Gross Income	GINCOM		
		Tax Obligations	TAXES		
		Cash Flow	CFLOW		
		Cost of Power	CSPWR	$	
26.	Write Details of Cash Flow Calculations for the Entire Life and the Required Cost of Power				ECONMN

VITA

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Doctor of Philosophy

Thesis: AN EVALUATION OF GEOTHERMAL ENERGY POTENTIAL

Major Field: Mechanical Engineering

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