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ADVANCED DESIGN AND ECONOMIC CONSIDERATIONS
FOR COMMERCIAL GEOTHERMAL POWER PLANTS AT
HEBER AND NILAND, CALIFORNIA

Final Report

October 1977

Work Performed Under Contract No. EY-76-C-03-1124

Bechtel Corporation
San Francisco, California

MASTER

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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**Prepared for
THE ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
Contract EY-76-C-03-1124**

**Prepared by
BECHTEL CORPORATION
SAN FRANCISCO, CALIFORNIA**

October 1977

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This study was conducted as a team effort by members of the Bechtel Corporation Research and Engineering Operation. Management responsibility rested with T. E. Walsh, Manager of the Power Technology Group and T. R. Fick, Project Manager. J. W. Hankin served as the Project Engineer and R. A. Hogue was the Lead Engineer. Major contributions were made by T. A. V. Cassel, Y. Choo, B. D. Kelly and A. Renton.

ABSTRACT

Two separate studies, involving advanced design and economic considerations for commercial geothermal power plants using liquid-dominated hydrothermal resources, are presented in this report. Both studies were conducted under contract to the United States Energy Research and Development Administration.

In the first study, the effects on design, capital cost, and bus bar electric energy production cost caused by an anticipated decline in available geothermal fluid temperature over the lifetime of power plants are described. A two-stage, flashed-steam energy conversion process was used for the conceptual design of the power plants, which operate from the moderate-temperature, low-salinity reservoir at Heber, California. Plants with net capacities of 50, 100, and 200 MWe (net) were investigated. The larger plant capacities require increased brine withdrawal rates from the reservoir and result in steeper brine temperature decline curves. These curves were calculated using a reservoir computer model. The results show that it is important to include provision for geothermal fluid temperature decline in the design of power plants to prevent loss of electric energy production capability and to reduce bus bar electric energy costs.

In the second study, the technical, economic, and environmental effects of adding regeneration to a 50 MWe (net) power plant employing the multistage-flash/binary process are described. This plant operates from the high-temperature, high-salinity resources at Niland, California. Regeneration is potentially attractive, because it recovers waste heat from the turbine exhaust and uses it in the power cycle. However, the pressure drop caused by the introduction of the regenerator decreases the turbine expansion and thus decreases system performance. An innovative approach was taken in the design of the regenerator, which minimized the expected performance degradation of the turbine. The result was that the performance, capital cost, and bus bar electric energy production cost are nearly the same for the processes with and without regeneration. On the other hand, the addition of regeneration has the environmental benefits of substantially reducing heat rejection to the atmosphere and cooling tower makeup and blowdown water requirements. It also increases the temperature of the brine returned to the field for reinjection.

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Section 1

INTRODUCTION

The goal of the Federal Geothermal Program is to stimulate commercial development of geothermal energy as an economic, reliable, and environmentally acceptable energy source (Ref. 1-1). The two studies in this report, accomplished under contract to the United States Energy Research and Development Administration (ERDA), directly support this goal by focusing on advanced design and economic considerations for commercial geothermal power plants using liquid-dominated hydrothermal resources. Resources of this type are important because they represent a substantial percentage of the national geothermal resources and can be used for electric energy production in the near term.

This study is a continuation of an earlier study completed in October 1976, also for ERDA. The earlier study developed conceptual designs and corresponding capital cost estimates for 50 MWe (net) geothermal power plants sited at Heber and Niland, California (Ref. 1-2). The Heber plant design was based on the two-stage flashed steam energy conversion process, and the Niland design was based on the multistage-flash/binary process.

Both Heber and Niland are located in the Imperial Valley in Southern California (see Figure 1-1). The Heber geothermal field has moderate temperature, low-salinity brine, while the Niland (or Salton Sea) geothermal field has high-temperature, high-salinity brine. These two fields were selected because the resultant studies give perspective on plant design and economics for the range of liquid-dominated hydrothermal resources that are of economic interest for electric power generation.

Figure 1-1. SITE LOCATION

The current studies build on the results of the earlier study by examining a different advanced aspect of each of the two plant designs, which could materially affect the approach taken to the final design of such plants. The objective of the current study at Heber was to investigate the effects on power plant design and economics for 50, 100, and 200 MWe (net) plants, which would be caused by an anticipated decline in the temperature of the brine supplied to the plants, over their 30-year economic lifetime. The objective of the Niland study was to determine the technical, economic, and environmental effects of adding regeneration to the multistage-flash/binary process designed in the earlier study. Both the current and the previous Niland studies were conducted for 50 MWe (net) plants, taking the initial reservoir conditions as constant over their lifetime.

This report is divided into three parts. In addition to this introduction, Part I includes summaries, conclusions, and recommendations from both the Heber and the Niland studies. Part II contains a

description of the methodology used for the Heber study and the results obtained. Part III includes similar information for the Niland study.

As previously mentioned, the work reported herein is a continuation of an earlier study. Both were funded by ERDA under Contract EY-76-C-03-1124.

Section 2

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

This section presents a summary of the basic objectives, assumptions, and results for both the Heber and Niland studies. Also included are the conclusions and recommendations that resulted from the two studies.

2.1 HEBER SUMMARY

2.1.1 Objective

The basic objective of this study was to investigate the effects on power plant design and economics for 50, 100, and 200 MWe (net) plants that would be caused by an anticipated decline in the temperature of the brine supplied to the plants over their 30-year economic lifetime.

2.1.2 Site

The town of Heber is located in the Imperial Valley of California, approximately five miles north of the U.S. boundary with Mexico and 100 miles east of San Diego. The plant site selected for this study is about one mile south of Heber. Climatic conditions are hot and arid with light winds.

Several geothermal wells have been drilled in the area of the plant site. Temperature, flow rate, salinity, and noncondensable gas content vary from well to well. Therefore, for the purposes of this study, representative values were assumed. These include an initial down-hole temperature of 360°F, a brine salinity of 14,000 parts per million, and a noncondensable gas content of 0.3 weight-percent of the steam

flashed from brine and expanded through the turbine. A free flowing 10-3/4-inch-diameter production well is assumed to have an initial flow rate of 800,000 pounds per hour. The production well flow rate decreases as the reservoir temperature declines over the life of the plants. A reinjection well, pumped at 315 psia, is assumed to have a constant flow rate of 1,600,000 pounds per hour over the life of the plants.

2.1.3 Plant Operating Modes

Geothermal reservoirs are depletable. As the hottest geothermal fluid is withdrawn and is replaced by the surrounding cooler fluid, both the mean temperature and the mean pressure will decline with time. The power output of a plant operating from such a reservoir would then decline unless the mass flow rate of supply brine were increased to compensate.

To accommodate an expected decline in brine temperature, two possible plant operating modes were considered. In the first mode, the plant operates at constant net power output throughout its 30-year lifetime. Brine flow rate to the plant is increased with time as the brine temperature declines. In the second operating mode, brine flow rate is held constant with time, and, consequently, plant output decreases. However, for the second operating mode, initial power output is increased, so that although the power output of the plant decreases with time, the energy generated over its 30-year lifetime is the same as that of the plant operating with constant power output. These two operating modes, "constant power output" and "constant brine flow rate" represent the envelope conditions within which all other operating modes would fall.

2.1.4 Computation Methods

The two-stage flashed steam energy conversion process is used for the power plants involved in the reservoir temperature decline study. Heat and mass balances were developed using a modified version of the GEOTHM computer program that was developed by the Lawrence Berkeley Laboratory. However, GEOTHM could not be used by itself for this purpose, because it does not contain equations that relate the steam flow rates simultaneously to the flash tank pressures and to the pressure changes across the stages of the turbine. These equations were not needed for previous applications of GEOTHM. To obtain the data needed for this study, a small computer program, named GEOPRS, was developed. It contains the needed equations and was used to generate input for GEOTHM which computed the heat and mass balances for this study. GEOPRS is described in the appendix to this report.

2.1.5 Reservoir Operation

Curves of expected downhole brine temperature as a function of time were needed, so that plant design conditions could be determined. Since temperature decline is related to the brine withdrawal rate, these brine temperature curves depend upon the plant design, primarily the power output of the plant and the plant operating mode. The relationships between the brine flow rate and net power output were developed for 50, 100, and 200 MWe plants designed for both the constant power output and the constant brine flow rate operating modes. These data were used by Chevron Resources, Inc. as input for their computer model of the Heber reservoir to obtain curves of brine temperature versus time for each plant design.

The results show that, as anticipated, the temperature decline is greater for the 200 MWe plants and successively less for the 100 MWe and the 50 MWe plants. However, the plant operating mode had a relatively small effect. Beginning with a 360°F downhole temperature,

temperatures after 30 years of operation were about 344°F, 334°F, and 318°F for the 50, 100, and 200 MWe plants, respectively.

2.1.6 Plant Design

A 50 MWe (net) plant, employing the two-stage flashed steam energy conversion process was conceptually designed during an earlier study (Ref. 1-2). This plant was designed with the assumption that the brine supply temperature would remain constant over its lifetime. In the study reported herein, this is the base case plant. The design of the base case 50 MWe (net) plant was appropriately modified to form 50, 100, and 200 MWe (net) plants composed of different 50 MWe (net) units designed for the constant brine flow rate and the constant power output operating modes. The design of the units for each of the three power output levels (50, 100, and 200 MWe) was different, because each has a different brine temperature decline rate. Plant performance was then calculated for ten different plants. Included are the 50 MWe base case plant with constant brine temperature, 50, 100, and 200 MWe (initial) base case plants operating with declining brine temperature, and 50, 100, and 200 MWe plants designed for the two different operating modes.

The net power outputs of the base case plants with declining brine temperature begin at 50, 100, and 200 MWe, but decline as brine temperature declines. Averaged over their lifetime, the equivalent power outputs for the 50 MWe units that comprise these 50, 100, and 200 MWe plants are 45.3, 43.4, and 39.9 MWe, respectively.

The brine flow rate for the 50 MWe units designed for constant power output constantly increases over the lifetime of the plants. The greatest increase occurs for the larger plants, because, as a result of greater reservoir drawdown, the brine temperature declines to a lower level and at a faster rate. The greatest increase in brine flow rate occurs for the 200 MWe plant. It begins at 40.8 million

pounds per hour in year 1 and increases to 68.0 million pounds per hour by year 30.

The net power for the 50 MWe equivalent units designed for constant brine flow rate begins in year 1 at a level higher than 50 MWe and ends in year 30 at a level lower than 50 MWe. The change in net power output over the life of the plants is greater for the larger plants, as described above, because brine temperature declines more rapidly with the larger plants. The greatest change in net power output occurs for the 200 MWe plant. It begins at 260.8 MWe (net) in year 1 and decreases to 165.0 MWe (net) in year 30, which is equivalent to 200 MWe over the 30 year period.

2.1.7 Plant and Well Field Capital Costs

The total estimated capital costs of the ten commercial geothermal power plants, and their associated wellfields, at Heber, California are outlined below. Each power plant is composed of one, two, or four 50 MWe (net) units, and each unit is designed specifically for the operating mode of the plant. The total plant capital costs, with high and low turbine-generator costs, and the total well field capital cost for years 1 and 30 of plant operation are given in Table 2-1. Because the turbine-generator is the major cost item in each plant, and a wide range of turbine-generator cost estimates were received, individual plant capital cost estimates were developed using both the high turbine-generator cost and the low turbine-generator cost.

The plant capital cost includes the cost of engineering and construction of all facilities within the plant site. The well field capital cost includes the cost of the production wells, reinjection wells, production well islands and associated equipment, reinjection well islands, and production and reinjection brine field piping. The estimates are expressed in fourth-quarter 1976 dollars and include an allowance for uncertainty.

Table 2-1

CAPITAL COST ESTIMATES
HEBER POWER PLANTS AND WELL FIELD

Plant	Plant Capital Costs				Well Field Capital Costs	
	High Turbine-Generator Cost		Low Turbine-Generator Cost		Year 1 (\$1,000)	Year 30 (\$1,000)
	(\$1,000)	\$/kWe(net)	(\$1,000)	\$/kWe(net)		
Base Case 50 MWe	35,000	700	30,400	608	16,600	16,600
Base Case with Declining Brine Temperature						
- 50 MWe unit of a 50 MWe (initial) plant	35,000	700	30,400	608	16,600	17,500
- 50 MWe unit of a 100 MWe (initial) plant	35,000	700	30,400	608	33,500(1)	35,600(1)
- 50 MWe unit of a 200 MWe (initial) plant	35,000	700	30,400	608	63,300(2)	72,200(2)
Constant Power Output Operating Mode						
- 50 MWe unit of a 50 MWe plant	36,000	720	31,400	628	17,400	19,500
- 50 MWe unit of a 100 MWe plant	36,500	730	31,800	636	35,400(1)	42,600(1)
- 50 MWe unit of a 200 MWe plant	38,200	764	33,400	668	64,800(2)	106,300(2)
Constant Brine Flow Rate Operating Mode						
- 50 MWe unit of a 50 MWe plant	37,500	750	32,300	646	17,100	18,000
- 50 MWe unit of a 100 MWe plant	38,500	770	33,100	662	36,500(1)	39,000(1)
- 50 MWe unit of a 200 MWe plant	41,400	828	35,400	708	72,700(2)	86,700(2)

Notes: (1) Well field cost for 100 MWe plant.
(2) Well field cost for 200 MWe plant.

2.1.8 Energy Production Costs

Energy production costs, expressed in mills per kilowatt-hour of net electric generation, are estimated for both the power plants and the well fields in arriving at a total bus bar cost of electric energy for the geothermal power facilities at Heber. The annual power plant energy cost, exclusive of the well field, is estimated by applying a level annual fixed charge rate, as used by a Southern California utility, to the plant's capital cost and adding to this product, estimated ad valorem taxes and expenses. This sum, when divided by the plant's levelized annual energy output at an assumed 85 percent capacity factor, produces a levelized power plant energy production cost ranging from about 19 to 24 mills per kilowatt-hour for the Heber plants investigated in this study (exclusive of well field costs).

The well field energy production cost for each plant investigated in this study is estimated from a discounted cash flow (DCF) analysis of capital investments, taxes, royalties, and other operating expenses over the life of the project. Two types of financing are assumed to estimate low and high limit energy costs. The low limit is based on low-risk, regulated utility financing of well field investments. A 10.8 percent DCF rate of return is used in this low-risk case, and an income tax deduction is claimed for the interest on 49 percent assumed debt financing. The high limit is based on risk-adjusted, energy company financing at a 20 percent DCF rate of return and no interest deduction (100 percent equity financing is assumed). A 10 percent investment tax credit is claimed in both the low and high limit cases. Depletion allowances and expensing of intangible well costs are not claimed in either case. Levelized annual total well field costs from the DCF analysis, divided by levelized annual power plant output at an 85 percent capacity factor, produce levelized well field energy production costs ranging from about 16 to 17 mills per kilowatt-hour for the low-limit and 27 to 30 mills per kilowatt-hour for the high-limit.

Total energy production costs for the combined power plants and well fields range from about 36 to 41 mills per kilowatt-hour for low-limit financing and 47 to 53 mills per kilowatt-hour for high-limit financing. Cost trends indicate that:

- Declining reservoir temperature causes a 6 to 8 percent increase over the energy production cost of identical power facilities operating from an ideal, constant temperature reservoir.
- Modifications in plant design to accommodate declining reservoir temperature result in a 4 to 7 percent decrease in the energy production cost compared to plants designed to operate at constant reservoir temperature.
- Plants designed to operate with constant brine flow as reservoir temperature declines are slightly more economic (i.e., energy production cost is 1 to 4 percent less) than plants designed to operate with constant power output.
- Increasing power plant capacity from 50 to 100 to 200 megawatts causes an increase of about 7 to 10 percent in the power plant energy production cost and a decrease of about 1 to 3 percent in the well field energy production cost. Total (power plant plus well field) energy production costs demonstrate a 3 to 4 percent increase as plant capacity increases.

2.2 HEBER CONCLUSIONS AND RECOMMENDATIONS

2.2.1 Conclusions

- To prevent a significant drop in generating capacity over their lifetime, geothermal power plants must be designed to operate with the anticipated progressive temperature decline of the incoming brine.
- It is technically feasible to design geothermal power plants employing the flashed steam energy conversion process to produce their rated capacity when operating with declining brine supply temperature and with either the constant brine flow rate operating mode or the constant power output operating mode.

- The choice of operating mode, either constant power output or constant brine flow rate, has relatively small effect on the performance of the plants as measured by specific net energy (watthours per pound of brine) over their 30-year life.
- To calculate heat and mass balances for a power plant employing the flashed steam energy conversion process and operating with declining brine supply temperature, a calculation procedure, such as used in the computer program GEOPRS, is necessary to relate the steam flow rates to the turbine stage pressure changes and to the flash tank pressures.
- Declining reservoir temperature causes a 6 to 8 percent increase over the energy production cost of identical power facilities operating from an ideal, constant temperature reservoir.
- Bus-bar costs of electric energy for geothermal power plants designed to accommodate declining brine temperature (in either the constant brine flow or constant power output mode of operation) are 4 to 7 percent lower than bus-bar costs of equivalent size plants not designed to accommodate a declining brine temperature but which, in actual operation, do experience temperature decline.
- The bus-bar cost of electric energy produced by geothermal plants subject to, and designed to accommodate, reservoir temperature decline at Heber is between 36 and 53 mills per kilowatt-hour, depending primarily on the type of project financing available (i.e., low-risk or risk-adjusted). It is probable that costs will be somewhat higher than the 36 mills per kilowatt-hour low limit because of the risks inherent in geothermal field development and plant operation.
- Little effect on the bus-bar cost of electric energy is caused by plant capacity increases from 50 to 100 to 200 megawatts or by the difference between the constant power output and the constant brine flow rate plant operating modes.

2.2.2 Recommendations

- Future geothermal power plant designs and corresponding economic assessments should take into account the potential effects of declining reservoir temperature that may occur over the lifetime of the plants.
- Long-term tests of liquid-dominated hydrothermal reservoirs should be conducted in conjunction with the operation of commercial capacity power plants, which would cause significant reservoir drawdown, to provide the data needed to verify and refine reservoir models.
- The calculation procedure of computer program GEOPRS should be incorporated as a subroutine into existing heat and mass balance programs, such as GEOTHM and GEOCOST, so that they can be used for future investigations of the effects of temperature decline on the design of flashed steam power plants.
- Rates of return on well field investments, tax deductions, and investment tax credits have a significant effect on the bus-bar cost of geothermal electric energy and should be carefully assessed in economic studies.

2.3 NILAND SUMMARY

2.3.1 Objective

The basic objective of this study was to determine the technical, economic, and environmental effects of adding regeneration to the multistage-flash/binary process that was designed in the earlier study. Both the current and the previous study were conducted for a 50 MWe (net) plant, taking the initial reservoir conditions as constant over the plant lifetime.

2.3.2 Site

The town of Niland is located in the Imperial Valley of California, approximately four and one-half miles east of the Salton Sea and 100 miles east of San Diego. The plant site selected for this study is about eight miles southwest of Niland. Climatic conditions are generally hot and arid with light winds. Makeup water for the cooling tower is obtained from the Alamo River, which is about 2.8 miles east of the plant site.

A number of geothermal wells have been drilled in the area of the plant site. Temperature, flow rate, salinity, and noncondensable gas content of the brine vary over wide ranges from well to well, depending primarily on depth and location in the field. For the purposes of this study, representative values were assumed. These include a downhole temperature of 550°F, a flow rate for a free flowing individual 10-3/4-inch-diameter production well of 800,000 pounds per hour, a flow rate of 1,600,000 pounds per hour for a 10-3/4-inch-diameter reinjection well pumped at 315 psia, a brine salinity of 250,000 parts per million, and a noncondensable gas content of 0.5 weight-percent of the total brine flow.

2.3.3 Plant Design

A 50 MWe (net) plant, employing the multistage-flash/binary energy conversion process and using isopentane as the working fluid, was conceptually designed during an earlier study. It is fully described in the final report for that study (Ref. 1-2). The current study modified the process to include regeneration. This involved introducing a new shell-and-tube heat exchanger in the isopentane loop between the turbine exhaust and the condenser. Waste heat that is recovered by this heat exchanger from the turbine exhaust vapor is used in the power cycle to preheat the liquid isopentane before it enters the multistage-flash units, which comprise the primary heat transfer equipment.

To achieve high plant performance for the process with regeneration, the pressure drop through the vapor side of the regenerator must be minimized. The reason is that pressure drop, introduced by the regenerator, reduces the turbine expansion and, thus, its output. To minimize this pressure drop, an innovative approach was taken by flowing the turbine exhaust vapor through the inside of the regenerator tubes rather than outside of the tubes. Since the regenerator recovers heat that would have been rejected to the cooling system and uses this heat to preheat the isopentane working fluid, reduction in the required duty and, therefore, the size of the entire cooling system and of the multistage-flash units resulted. These systems were conceptually designed for the regenerative process. As part of this design effort, the performance of the plant was calculated with a modified version of the computer program GEOTHM that was developed by the Lawrence Berkeley Laboratory.

For the plant with regeneration to transmit 50 MWe to the power grid and supply the additional power required by its auxiliary systems, energy must be extracted from the brine at a rate that produces 55.1 MWe gross output from the turbine-generator. Without regeneration the gross output is 55.6 MWe. This requires a brine flow rate of 3.67 million pounds per hour for the process with regeneration and 3.60 million pounds per hour for the process without regeneration. The specific net energy for the processes with and without regeneration are then 13.6 and 13.9 watt-hours per pound of brine, respectively.

Environmental impact, including heat rejection to the atmosphere, the consumptive use of water for cooling tower makeup, and cooling tower blowdown requirements are substantially reduced for the process with regeneration. Compared to the baseline process without regeneration, evaporation and drift from the cooling tower is reduced from 1.02 to 0.83 million pounds per hour, makeup is reduced from 3,270 to 2,650

acre-feet per year, and blowdown from 0.51 to 0.41 million pounds per hour. Additionally, the addition of regeneration results in an increase of 75°F in the temperature of the brine returned to the field for reinjection. This higher brine return temperature may have beneficial effects on scale formation in the reinjection lines and wells, and on reservoir longevity.

2.3.4 Capital Costs

The estimated total capital cost for the 50 MWe (net) multistage flash/binary commercial power plant without regeneration at Niland, California, is \$39.5 million (\$790/kWe(net)). With regeneration, the plant cost is \$39.2 million (\$784/kWe(net)). Engineering and construction of all facilities within the plant site are included in the cost estimates. The estimate is expressed in fourth-quarter 1976 dollars and includes an allowance for uncertainty. These plant capital costs do not include the well field capital costs, which are given in the following paragraph.

The total estimated well field capital cost for the 50 MWe multistage flash/binary commercial power plant, with or without regeneration, at Niland, California, is \$10.77 million. The well field capital cost includes the cost of the production wells, reinjection wells, production well island and associated equipment, reinjection well island, and piping for production brine, reinjection brine, and cooling tower blowdown. The estimate is expressed in fourth-quarter 1976 dollars and includes an allowance for uncertainty.

2.3.5 Energy Production Costs

Energy production costs for the Niland plants are estimated by the same approach used for the Heber plants that is summarized in Section 2.1. For the multistage flash/plant at Niland without regeneration, the cost of energy produced by the power plant (exclusive of well field costs) is estimated to be 24.2 mills per kilowatt-hour. Because of

a slightly lower capital cost, the cost of energy produced by the power plant with regeneration is 24.0 mills per kilowatt-hour.

Both the plants with and without regeneration have essentially the same well field requirements and, thus, the same well field energy production costs. As in the Heber study, for the Niland plants both a low limit and a high limit well field energy production cost were estimated. The low limit for both plants is 10.2 mills per kilowatt-hour, while the high limit is 17.0 mills per kilowatt-hour.

Total energy production costs at the bus bar for the combined well field and power plant range from a low of 34.4 mills per kilowatt-hour to a high of 41.2 mills per kilowatt-hour for the plant without regeneration. For the plant with regeneration, the range is from 34.2 to 41.0 mills per kilowatt-hour.

2.4 NILAND CONCLUSIONS AND RECOMMENDATIONS

2.4.1 Conclusions

- A commercial 50 MWe (net) power plant based on the multi-stage flash/binary energy conversion process with regeneration, using isopentane as the working fluid is technically feasible for the hydrothermal site near Niland, California, and can be constructed using in-sight technology.
- The total flow rate of 550°F brine (downhole) required by the 50 MWe (net) power plant with regeneration is 3.67×10^6 pounds per hour when operating at full rated capacity. The specific net energy of the plant is then 13.6 watt-hours per pound of brine. Without regeneration, the brine flow rate is 2 percent less and the specific net energy is 2 percent greater.
- The addition of regenerators to the multistage flash/binary process recovers waste heat from the turbine exhaust and uses it in the power cycle. However, the resulting performance improvement is counterbalanced by the decrease in turbine expansion caused by the pressure loss through the vapor side of the regenerators and the decrease in heat extracted from the brine which results in an increase in brine reinjection temperature.

- The pressure loss through the vapor side of the regenerator and the resulting process performance decrease can be minimized by designing the regenerators so that the isopentane vapor flows through the tubes rather than outside the tubes as in the conventional approach.
- The addition of regeneration does not significantly affect the power plant land area requirements. Approximately 8 acres will be required in either case.
- With regeneration, the brine reinjection temperature is increased by 75°F over the process without regeneration. The higher temperature would tend to decrease scaling in the reinjection wells and may have a beneficial effect on reservoir longevity.
- The addition of regeneration causes a reduction of nearly 20% in heat rejection to the atmosphere by evaporation and drifts from the cooling tower, in cooling tower blowdown, and in the consumptive use of water for makeup in the cooling tower.
- The regenerator eliminates the need for a noncondensable gas pumping system and the associated cost.
- The estimated total capital cost for the 50 MWe (net) multi-stage flash/binary power plant without regeneration is \$39.5 million, or \$790/kWe (net), and with regeneration is \$39.2 million, or \$784/kWe (net). The total estimated well field cost for either power plant is \$10.77 million. The estimates are expressed in fourth-quarter 1976 dollars and include an allowance for uncertainty.
- The addition of regeneration results in a reduction of less than 1 percent in the total bus-bar cost of electric energy for the combined well field and power plant. For the plant with regeneration, the energy production cost ranges from 34.2 to 41.0 mills per kilowatt hour, depending primarily upon the type of well field financing available (i.e., low-risk or risk adjusted).

2.4.2 Recommendations

- Regeneration should be considered for use in future binary plant designs because of the improvements in environmental effects and the possible benefits from increased brine reinjection temperature.

- Long-term field tests should be conducted to determine the effects of brine reinjection temperature on scaling in the reinjection lines and reinjection wells, reinjection pumping pressure, and on reservoir temperature. These tests should be coordinated with reservoir computer model studies.
- Pilot-scale tests should be conducted with geothermal brine to improve the performance of the major process equipment items, such as the multistage flash units and the separator-heat exchanger. These tests should include the effects on the equipment being tested of the addition of regeneration to the energy conversion process. One specific series of test should involve various regenerator tube types and configurations to minimize pressure losses, improve heat transfer performance, and optimize equipment cost.
- A study should be performed for power plants of various capacities that are based on the multistage flash/binary process to determine the effects on plant design and economics caused by a decline in the temperature of the brine supplied to the plants over their economic lifetime.

Section 3

RESERVOIR AND PLANT OPERATION

3.1 SITE DESCRIPTION

3.1.1 Location

The plant site is about one mile south of the town of Heber, within the Heber Known Geothermal Resources Area. Heber is located in the southern part of the Imperial Valley of California, approximately five miles north of the international boundary with Mexico. The plant site is situated on level agricultural land. An area of about 10 acres is required to accommodate all facilities for a single 50 MWe unit within the power plant boundary. The 100 MWe power plant requires about 18 acres, and the 200 MWe plant requires about 36 acres.

3.1.2 Climatic Conditions

The Imperial Valley is a hot arid region, lying mostly below sea level. Climatic conditions used in this study are based on Yuma, Arizona, which is 53 miles east of the Heber site. Yuma conditions were used because complete data are available that are representative of the Heber area. The design conditions are based on a summer prevailing wind from the southeast at 8.5 mph and temperatures of 111^o F dry bulb and 79^o F wet bulb. These temperatures are equaled or exceeded during only 1 percent of the hours of June through September of an average year. The mean daily dry bulb temperature ranges from 55^o F in January to 93^o F in July.

3.1.3 Brine Supply and Reinjection

The temperature, salinity, and noncondensable gas content of the geothermal brine from the existing wells varies over wide ranges. For design purposes representative values are used.

Brine delivered from the production wells experiences a drop in pressure as it rises in the well bore and a further drop due to line and valve losses. As a result, it flashes in the line and is supplied to the power plant as a two-phase mixture. The brine is assumed to have a downhole temperature of 360°F at saturated liquid conditions, to expand at constant enthalpy, and to be supplied to the power plant in the two-phase state at a temperature of 338°F and a pressure of 115 psia.

The total dissolved solids content of the brine is 14,000 ppm, and the pH is approximately 6.2. The brine is flashed to steam, which becomes the plant working fluid; the steam contains 0.3 percent by weight of noncondensable gases. After exhausting from the turbine, the steam is condensed and most of it is used for cooling tower makeup. The excess condensate, which serves as cooling tower blowdown, is combined with the discharge brine and is returned to the well field for reinjection. The combined fluids leave the plant as a liquid, at a pressure of 315 psia, which is the nominal pressure needed for reinjection.

3.1.4 Water Supply

A main irrigation water supply canal is located approximately 500 feet south of the plant site. Water, pumped from this canal, can be stored in a pond at the plant to supply the fire protection system.

An outside source of makeup water is not normally required as the added flow of condensate to the cooling system is greater than all evaporation and drift losses in the cooling tower. However, water could be pumped from the New River if supplementary water is required for brine reinjection to prevent ground surface subsidence.

3.1.5 Electrical Transmission

Two subtransmission feeder lines exist that can be used to connect the plant switchyard to the Imperial Irrigation District's network, which presently has a substation one mile north of the plant site.

3.2 PLANT OPERATING MODES

3.2.1 General

All geothermal reservoirs are finite sources of thermal energy. As the hottest geothermal fluid is withdrawn and is replaced by the surrounding cooler fluid, both the mean pressure and the mean temperature of the geothermal fluid (brine) within the reservoir would decline as functions of time. Since the heat content of each pound of brine flowing into the geothermal power plant would then decline, the capacity of the power plant would also decline unless the mass flow rate of brine were increased to give an in-flow rate of energy to the plant required to maintain the initial rated plant capacity.

Although electric utility companies traditionally maintain plant capacity constant for convenience of planning and operation, there is no technical reason prohibiting a plant from operating with progressively declining capacity. However, the plant's design and economics would be configured differently than is the present usual practice.

To accommodate an expected decline in geothermal brine temperature, two possible plant operating modes were considered. In the first mode, the plant operates at constant net power output throughout its 30-year lifetime. Brine flow rate must be increased with time as brine temperature and enthalpy decline. In the second operating mode, brine flow rate is held constant with time and, consequently, plant output decreases. These two operating modes represent the "envelope conditions" or "boundary conditions" within which all other operating modes would fall. All other modes will be a combination or variation of these two modes.

To provide a basis of comparison for power plants designed for the operating modes discussed above, a base case 50 MWe double-flash geothermal power plant was conceptually designed for the Heber site. This design incorporated the apparently traditional assumption that constant geothermal brine supply temperature is maintained throughout the plant's lifetime.

3.2.2 Constant Power Output

Initial rated plant capacity can be maintained by compensating for a progressive decline in available brine temperature by feeding a gradually increasing mass flow rate of brine into the plant. For the purposes of this study, this mode of plant operation, which is illustrated by example curve 1 (straight line) in Figure 3-1, is called the "constant power output operating mode." This is equivalent to constant plant capacity.

A plant designed to accept only the required flow rate of hotter brine during the first year of reservoir operation will not be adequate to accommodate the needed higher flow rates of cooler brine in later years. Consequently, a plant design that is markedly different from that dictated by constant reservoir conditions will be required. Furthermore, plant economics will be affected.

Three power plants, having capacities of 50 MWe, 100 MWe, and 200 MWe respectively, and designed for the constant power output operating mode, were studied. Each of the three plants consists of one to four 50 MWe units, which are modifications of the base case 50 MWe plant designed for constant geothermal brine temperature.

3.2.3 Constant Brine Flow Rate

Mass flow rate of brine into the plant can be maintained at a constant level, and plant capacity will decrease progressively with declining brine temperature. This mode of plant operation, which is illustrated

Figure 3-1. POWER OUTPUT VERSUS TIME

by example curve 2 in Figure 3-1, is called the "constant brine flow rate operating mode." A plant having an initial net capacity of 50 MWe and designed to operate with a constant brine flow rate and declining capacity will generate less electric energy during its 30-year lifetime than a 50 MWe plant designed to operate at constant power output during the same period of time. It would be meaningless to try to compare these two plants both technically and economically since the plants are not equivalent. The plant designed for constant brine flow rate can be made to be equivalent to the plant designed for constant power output by selecting its initial capacity to be large enough so that although its capacity will decline with time, the total quantity of electric energy generated in 30 years will equal that generated in the same time by the plant designed for constant power output. This concept of equivalence is illustrated by the example curves in Figure 3-1. The surface areas under the curves are equal, since these areas are the products of net power and time, and therefore represent the quantities of energy generated by the plants. Consequently, the shaded areas, E1 and E2, are equal.

Three power plants, having equivalent net capacities of 50 MWe, 100 MWe, and 200 MWe, respectively, and designed for the constant brine flow rate operating mode, were studied. Each of these plants consists of one to four 50 MWe units, which are modifications of the base case 50 MWe plant designed for constant brine temperature.

3.3 PLANT CONTROL

3.3.1 Plant Control Methods

The power output from the turbine can be controlled by controlling either the brine flow to the flash tanks or the steam flow to the turbine. A disadvantage to controlling steam flow is that throttling steam at the inlet to the turbine causes additional pressure drop in the steam lines, which significantly reduces the overall efficiency

of the power plant. It is preferable to control the brine flow to the flash tanks, since the energy losses that result from the additional pressure drop in the brine line are negligible compared to those that result from throttling steam. Throttling brine flow to the flash tanks was selected as the method of plant control employed in all plants designed in this study.

3.3.2 Computation Methods

The steam turbine for a geothermal power plant employing the flashed-steam energy conversion process is designed to admit steam at specified inlet pressures. Assuming that the plant is controlled by throttling brine flow, as discussed above, the flash pressures will not change significantly from their design values if the brine inlet temperature to the flash tanks remains nearly constant over the life of the plant. If brine temperature declines appreciably, however, the flash tank pressures will adjust themselves so that the steam flow rate passed by the turbine equals the flow rate of steam flashed in the tanks. As a result, the turbine inlet pressures and all of the plant flow rates will be different from their design values.

It was initially planned to use a computer program GEOTHM, which was developed by the Lawrence Berkeley Laboratory (Ref. 3-1). This program calculates the heat and mass balances for the power plants based on the brine temperature decline curves provided by Chevron Resources, Inc. and included in Section 3.4. The program can be coded to calculate heat and mass balances for various power plant designs. When GEOTHM is coded for the two-stage flashed steam plant design, it calculates the fraction of steam flashed from the brine in the first- and second-stage flash tanks, based on input operating pressures for the two tanks. A turbine that fully utilizes the resultant steam flow is then assumed by the program, and a heat and mass balance based on this turbine is calculated. The program assumes a different turbine if different flash pressures are input.

The present study requires that plant heat and mass balances be calculated for varying flash pressures with the same turbine. As the brine temperature declines, the flash pressures are affected by the change in turbine stage pressure. To calculate the flash tank pressures, equations that relate steam flow rates to pressure changes across the turbine stages must be satisfied. These equations are not in GEOTHM because they were not needed for its previous applications.

It was determined that the most expedient method for obtaining the data needed for this study would be to write a separate small computer program that contains the necessary turbine equations. The calculation procedure for this new program, named GEOPRS, is described in Appendix A.

Beginning with a given plant design and a given initial brine temperature, plant heat and mass balances for declining brine temperatures are calculated as follows. First, GEOTHM is run to calculate an initial heat and mass balance based on the plant design and initial brine temperature. Data from this heat and mass balance and data for the given turbine are used as input to GEOPRS, which calculates constants for the turbine equations. The program then uses these same turbine constants to calculate new flash pressures based on different brine temperatures. Finally, these flash pressures are used as input to the program GEOTHM, which is run again to calculate heat and mass balances corresponding to the different brine temperatures.

The calculation procedure for GEOPRS could be used as the basis for a subroutine to be incorporated into codes such as GEOTHM and GEOCOST (Ref. 3-2). Sufficient detail is given in Appendix A to allow the originators of such existing codes to incorporate this capability for any future investigation of the effects of temperature decline on the design of flashed steam power plants.

3.4 RESERVOIR OPERATION

3.4.1 Reservoir Model

The computer program used by Chevron Resources, Inc. to predict the reservoir performance at Heber is a two-dimensional, layered simulator, which accounts for non-unit mobility ratios, areal and vertical sweep variations, while assuming no cross-flow between layers. Incompressible flow and no fluid recharge across the reservoir boundaries are also assumed.

The Chevron Heber model used 15 geologic layers, each layer having its own permeability and porosity. The variation in permeability from the highest to the lowest is about 9:1. After some initial period of time, the reinjected fluid moving through the layers with the highest permeability will have advanced to the region of the production wells. After more time, the fluid moving through the layers having the next highest permeability will arrive at the production wells. Consequently, a vertical cross section of the reservoir would reveal a profile of reinjected fluid. On the average over a 30-year period, 80 percent of the reservoir's pore volume will have been replaced by reinjected fluid.

However, with proper location of the reinjection wells, the effect of the reinjected fluid on the temperature of the produced fluid is minimal. Spent brine is assumed in the computer program to be reinjected at 200°F into rock slightly above 200°F. Since the heat capacity of the rock is large compared to that of the brine, the rock will rapidly heat the reinjected brine. Calculations by the Chevron computer program indicate that the produced fluid is only about 0.1°F to 0.2°F cooler after 30 years due to the influence of the reinjected fluid. Therefore, the temperature of the reinjected brine has a negligible effect upon the producing temperature over the project life.

Temperature decline occurs because produced brine is replaced by cooler brine already in the reservoir. The hottest fluid resides in the center of the reservoir, and the fluid is cooler at greater distances from the center. Production wells are drilled near the hottest fluid at the reservoir center, while reinjection wells are drilled one to two miles out from the center. As the hottest fluid is withdrawn, it is replaced by cooler fluid moving toward the center. Consequently, temperature decline occurs immediately after commencement of brine production and not after reinjected fluid first reaches the production wells.

3.4.2 Input Data

Constant Power Output Operating Mode. Curves of expected downhole brine temperature as a function of time were needed for the purpose of determining plant design conditions. The Chevron computer model of the Heber reservoir is capable of calculating the rate of brine temperature decline that corresponds to a given mass flow rate of brine withdrawn from the reservoir. However, the withdrawal rate of brine by the 50, 100, and 200 MWe plants designed for the constant power output operating mode changes continuously in order to maintain the net power generated by the plants at a constant level. Consequently, it was necessary to provide Chevron with data that describe the change in brine flow rate over a range of brine temperatures for each of the three plants designed for constant power output.

Assuming 50, 100, and 200 MWe plants, program GEOPRS was run to calculate the flash pressures that would result from brine at various downhole temperatures. These same brine temperatures and the corresponding flash pressures were then used as input to program GEOTHM to calculate the brine flow rates required by the 50, 100, and 200 MWe plants at the various downhole brine temperatures. Curves of brine flow rate as functions of downhole brine temperature for each of the three plants

were plotted using the computer output data. These curves, which are presented in Figure 3-2, were then used as input to the Chevron reservoir model, which calculated a corresponding curve of declining brine temperature over time for each of the three plants. These curves are presented in Section 3.4.3.

Constant Brine Flow Rate Operating Mode. Unlike the plants designed for constant power output, the rate of brine withdrawal from the reservoir for a particular plant designed for the constant brine flow rate operating mode does not change with time. Therefore, it was only necessary to provide Chevron with the constant flow rates.

In order to develop conceptual designs, net power was plotted as a function of time for six different constant flow rates each for the 50, 100, and 200 MWe plants. A single curve of constant flow rate corresponding to the desired plant conditions was then selected for each capacity plant (50, 100, and 200 MWe) by interpolating between these curves. To accomplish this, a curve of downhole brine temperature as a function of time was required from Chevron for each of the eighteen brine withdrawal rates, which are listed in Table 3-1. The resulting curves are presented in Section 3.4.3.

3.4.3 Reservoir Temperature Decline

Input data were developed by Bechtel for the Chevron reservoir computer model, as described above. Chevron used the brine flow rate versus brine temperature data presented in Figure 3-2 to generate Figure 3-3, which shows brine temperature versus time for 50, 100, and 200 MWe plants designed for the constant power output operating mode.

The constant brine flow rates listed in Table 3-1 were used by Chevron to generate the temperature decline data needed to develop "equivalent" 50, 100, and 200 MWe plants designed for the constant brine flow rate

Figure 3-2. BRINE FLOW RATE VERSUS DOWNHOLE BRINE TEMPERATURE FOR CONSTANT POWER OUTPUT OPERATING MODE

Table 3-1

CONSTANT BRINE FLOW RATES

Curve Number	50 MWe Plant Brine Flow Rate (10^6 lb/hr)	100 MWe Plant Brine Flow Rate (10^6 lb/hr)	200 MWe Plant Brine Flow Rate (10^6 lb/hr)
1	10.0	20.0	40.0
2	12.0	24.0	48.0
3	14.0	28.0	56.0
4	16.0	32.0	64.0
5	17.3	34.6	69.2
6	20.0	40.0	80.0

Figure 3-3. Heber Geothermal Field Temperature Decline with Time at Constant Power Output

operating mode. The 18 temperature decline curves that correspond to the constant flow rates in Table 3-1 are shown in Figure 3-4. By interpolating between these curves, a temperature decline curve for each of the equivalent 50, 100, and 200 MWe plants was obtained. This interpolation requires several steps; the details are described in Section 4.4.1. The temperature decline curves for the three plants designed for constant brine flow rate are shown in Figure 3-5, which also includes the three temperature decline curves for the plants designed for constant power output.

In the early years of operation of plants designed for constant brine flow rate, net power and, therefore, brine withdrawal rate are greater than for the plants designed for constant power output (refer to Figure 3-1). Consequently, the brine temperature declines more rapidly for these plants in the early years, as can be seen in Figure 3-5. In the later years of plant operation, however, the brine withdrawal rate is less for the plants designed for constant brine flow rate. Therefore, the brine temperature declines less rapidly in the later years than for the plants designed for constant power output. It is interesting to note, however, that, despite these slight differences, the choice of operating mode for plants having equivalent capacities has relatively little effect on the rate of temperature decline.

Figure 3-4. HEBER GEOTHERMAL FIELD TEMPERATURE DECLINE WITH TIME AT SIX CONSTANT BRINE FLOW RATES

Figure 3-5. HEBER GEOTHERMAL FIELD TEMPERATURE DECLINE WITH TIME

Section 4

CONCEPTUAL DESIGNS OF POWER PLANTS

4.1 GENERAL

A 50 MWe (net) geothermal power plant, employing the two-stage flashed-steam energy conversion process, was conceptually designed for the geothermal brine conditions at the Heber site. This design, based on the assumption that the downhole brine temperature remains constant at 360°F during the lifetime of the plant, was taken as the base case. To accommodate the expected decline in downhole brine temperature, two different plant operating modes were investigated, constant brine flow rate and constant power output. These are described in Section 3. Plants with net capacities of 50, 100, and 200 MWe were conceptually designed for each of these two plant operating modes. The plants consist of one to four 50 MWe units, which are modifications of the 50 MWe base case plant, designed for constant brine temperature.

4.2 BASE CASE PLANT

4.2.1 Energy Conversion Process

In the previous study (Ref. 1-2), a two-stage flashed-steam energy conversion process was found to be more cost effective than either a one-stage process or a three-stage process. The two-stage process was therefore selected for the base case plant. Figures 4-1 and 4-2 show the schematic diagram and the cycle diagram, respectively, for the two-stage flash process. Numbered points in the schematic diagram correspond to those in the cycle diagram.

In the flashed-steam process, steam is produced from the geothermal brine by reducing the pressure of the brine below its vapor pressure. Brine is

first flashed in a high pressure vessel. The remaining brine is piped to a low pressure vessel where a second flash takes place. Steam at two pressures from these vessels is admitted directly into a dual-admission turbine, which drives an electric generator. A low turbine back pressure is maintained by condensing the turbine exhaust vapor in a direct contact condenser with cooling water from a mechanical draft evaporative cooling tower. Makeup water for the cooling tower is supplied from the clean turbine exhaust condensate, thereby eliminating the need for an outside water supply for this purpose.

4.2.2 Facility Layout

The plot plan of the 50 MWe base case plant is shown in Figure 4-3. This drawing shows the arrangement of buildings, major outdoor equipment, site improvements, and brine supply and reinjection piping. The plant site itself is a rectangular 10-acre plot. The cooling tower is aligned in the most favorable direction for prevailing winds. The turbine building houses the turbine-generator, auxiliary equipment, circulating water pumps, condenser, switchgear, and the air conditioned control room and office and is located in the center of the plant site.

The 100 MWe plant designed for either of the two operating modes discussed earlier is comprised of two similar 50 MWe units, the second unit located directly north of the first unit. The second turbine building is connected to the first turbine building in an end-to-end arrangement and with a common control area between them. The cooling tower for the second 50 MWe unit is located north of both turbine buildings and is aligned in the same direction as the cooling tower for the first unit.

The 200 MWe plant consists of two of the 100 MWe plants just described and is sited on part of a quarter section of land as shown in Figure 4-4. The rectangles of land containing the 50 MWe units are located

Figure 4-3. PLOT PLAN: 50 MWe (NET) FLASHED STEAM POWER PLANT HEBER, CALIFORNIA

Figure 4-4. PLANT ARRANGEMENT: 200 MWe (NET) FLASHED STEAM POWER PLANT HEBER, CALIFORNIA

along the edges of the larger square section to preserve as much as possible of the remaining agricultural land. In addition, the rectangles are offset with respect to each other so that the cooling towers on the west side are not directly downwind of the cooling towers on the east side. Production well islands are located in each of the four corners of the square section, and to minimize piping each 50 MWe unit receives brine from the nearest well island.

4.2.3 Conceptual Design

The major equipment items, connecting piping, and major valves and controls of the 50 MWe base case plant are shown in Figure 4-5 (Drawing M-300). The auxiliary power requirements of the base case plant are included in Table 4-1.

Table 4-1

AUXILIARY POWER REQUIREMENTS
50 MWe (NET) GEOTHERMAL POWER PLANT
HEBER, CALIFORNIA
BASE CASE

	Shaft Power (bhp)	Electric Power (kW) (1)
Brine Reinjection Pumps	3,900	3,160
Circulating Water Pumps	3,540	2,850
Ejector Condenser Pumps	50	40
Scrubber Water Supply Pumps	20	15
Condenser Vacuum Holding Pump	100	85
Subtotal		6,170
Cooling Tower Fans (total)		1,150
Power for Other Services (estimated)		300
Total Auxiliary Power		7,600
Net Electrical Output from Unit		50,000
Gross Power Generated		57,600

Note: (1) Electric motor efficiency = 92%

As illustrated in the flow diagram, the energy conversion process includes three major fluid systems:

- Geothermal brine system
- Steam system
- Cooling system

The geothermal brine system supplies the heat energy for the process. Total brine at a flow rate of 10.1×10^6 pounds per hour (lb/hr) at downhole conditions of 360°F and 152 psia (338°F and 115 psia plant site conditions) is supplied to the power plant from the production wells. The pressure is reduced to 50 psia in the two first-stage flash tanks, producing a total of 0.876×10^6 lb/hr of 50 psia steam. The unflashed portion of the brine at 50 psia flows to the two second-stage flash tanks, where the pressure is reduced to 17 psia. A total of 0.588×10^6 lb/hr of 17 psia steam is produced in the two second-stage flash tanks. A remaining total flow rate of 8.64×10^6 lb/hr of unflashed brine at 220°F mixes with 0.06×10^6 lb/hr of cooling tower blowdown, and the combined flow, 8.69×10^6 lb/hr, is pumped to the reinjection wells at a pressure of 315 psia.

The steam system contains the flashed steam, which produces power by expanding through a steam turbine in an open Rankine cycle. A 7 percent pressure drop is allowed in the steam piping between the flash tanks and the turbine inlet control valves for both high pressure and low pressure steam. High pressure (46.5 psia) steam flowing at a rate of 0.426×10^6 lb/hr from each of the two first-stage flash tanks expands through two double-flow dual-admission turbine elements in mechanical series with the generator. An additional 0.024×10^6 lb/hr of high pressure steam is required to operate the first-stage steam jet ejector, which in combination with a second-stage vacuum pump removes noncondensable gases from the condenser.

Low pressure (15.8 psia) steam, flowing at a rate of 0.147×10^6 lb/hr from each of four low pressure steam supply lines, is admitted to the steam turbine, with one admission to each of the four steam expansion paths. The second-stage steam then mixes at the admission point of the turbine with first-stage steam expanded to the admission pressure. The combined flow of 0.360×10^6 lb/hr expands, in each of the four steam expansion paths, to the design exhaust pressure of 4 inches of mercury absolute, which is maintained in the direct-contact condenser. Cooling water is sprayed inside the condenser and contacts and condenses the steam exhausting from the turbine.

The cooling system provides the heat sink for the process, first rejecting heat through the cooling water and then dissipating it to the atmosphere. Cooling water from the tower flows into the direct contact condenser, and the mixture of cooling water and condensate is pumped back to the cooling tower, where it is cooled by evaporation.

Cooling water enters the condenser at 87°F , and the mixture returns to the tower at 115°F . The added flow of condensate to the circulating water is more than all evaporation and drift losses in the tower; therefore, an outside source of makeup water is not required. The quantity of condensate that exceeds the quantity of water lost through the cooling tower is pumped to reinjection wells. If, to prevent ground surface subsidence, it is required that the brine reinjection flow rate be equal to the brine production flow rate, water from the New River can be reinjected in separate reinjection wells. It may be necessary to chemically treat this water prior to reinjection to make it compatible chemically with the downhole geothermal brine.

The mechanical equipment described in the following paragraphs were either conceptually designed (such as the flash tanks and condenser) or were selected from commercially available equipment (such as pumps and cooling towers). Standard power plant design practice was followed in the selection and arrangement of plant equipment. In addition, the plant was designed to minimize auxiliary power requirements, without

adding excessively to plant investment costs. Expected pump reliabilities were considered in determining if a standby pump was required for each application. A brief description of each of the major mechanical equipment items follows.

First- and Second-Stage Flash Tanks (T-1A, T-1B, and T-2A, T-2B).

Operating experience with seawater desalination plants dictated the design of the flash tanks. In a typical multistage flash (MSF) evaporator used for the distillation of seawater, the low pressure involved (30 psia) permits the design of a rectangular flash chamber. However, higher steam pressures are available from the geothermal brine resources at Heber, and a cylindrical vessel is more economical.

There are two constraints on vessel dimensions. The first is that sufficient height must be provided above the flashing brine to permit disengagement of liquid droplets from the ascending vapor steam. Secondly, the diameter and length of the vessel must be adequate to provide the required mist eliminator area. The first- and second-stage flash tanks are 24 feet long and 25 feet long, respectively. All four tanks are 11.25 feet in diameter.

Flash tank internals include a flashing device and mist eliminators, as shown in Figure 4-6. The flashing device was designed to minimize vessel size and improve operation. The hot geothermal brine is ejected from a series of holes along the top of a pipe lying on the bottom of the tank. The jet is constrained by a shroud on either side of the pipe, impinging on a curved baffle that deflects the two-phase flow downward and toward the sides of the tank. Two mist eliminators are included in each of the flash tanks. The first is sprayed with cooling water to remove impurities from the steam. The second is dry and is used to remove mist carryover from the first mist eliminator.

Turbine-Generator (K-1A, K-1B). An axial flow turbine configuration with two double-flow dual-admission elements was selected for the base case plant at Heber. The turbine delivers 58.2 MW_m to drive the main generator, which turns at 3,600 rpm; and produces 50 MWe net electrical

Figure 4-6. SCHEMATIC OF FLASH TANK FOR GEOTHERMAL BRINE

power plus an additional 7.6 MWe for the plant auxiliaries. Two elements were required to accommodate the relatively low pressure and large volume flow with conventionally sized equipment. The hood inner diameter for each element is about 10 feet. The turbine expansion efficiencies furnished by the turbine manufacturer are 77 percent for the high pressure expansion and 79 percent for the low pressure expansion. The turbine mechanical efficiency is 99.5 percent, and the generator electrical efficiency is 99 percent.

Condenser (C-1). A low-level direct contact condenser is located directly beneath the turbine. The condenser consists of cooling water distribution pipes and spray nozzles enclosed within reinforced concrete walls. The outside dimensions are 31 feet wide, 52 feet long, and 34 feet high. The insides of the concrete walls are sealed with an epoxy resin compound. The condenser duty is 1.36×10^9 Btu/hr. Direct contact condensers have several advantages over surface condensers:

- Direct contact action permits a close approach to be readily achieved between the temperature of the condensing steam and that of the cooling water leaving the condenser. Based on experience with direct contact condensers, a practical design approach of 10°F was selected.
- Direct contact condensers do not require heat transfer tubes, which contribute a substantial amount to the cost of surface condensers.
- The absence of tubes in a direct contact condenser obviates the danger of fouling by gases in the geothermal vapor and by scaling constituents in the cooling water.

Cooling Tower (E-1). The plant's total heat rejection load is dissipated in a mechanical draft evaporative cooling tower comprising ten cells, each 36 feet long, 53 feet wide, and 60 feet high. An evaporative-type tower has the advantage of cooling the water to a lower temperature than is possible with a dry tower, thus reducing the back pressure on the turbine and improving its performance. Hydrogen sulfide dissolved

in the cooling water will be released from the cooling tower, but the amount is less than the allowable emission level.

Steam Jet Ejector (J-1)/Vacuum Pump (A-3). To maintain condenser vacuum, noncondensable gases must be removed from the condenser by an ejection system that operates between the condenser pressure of 4 inches mercury absolute and a pressure slightly above 30 inches mercury absolute so that the gases can be vented to the atmosphere. Two steam jet ejectors in series may be used for this purpose. A reasonable design includes a first-stage ejector that compresses the gases from 4 inches mercury absolute to 20 inches mercury absolute and a second stage ejector that compresses from 20 inches mercury absolute to 30 inches mercury absolute.

Cooling water sprayed in the cooling tower collects entrained air, which is released in the direct contact condenser and is added to the geothermal gases. Consequently, the amount of noncondensable gases, which are removed by the ejector vacuum pump system, is slightly greater than 0.3 percent by weight of steam, assumed to be the level of noncondensable gases originating solely from geothermal sources.

Performance of steam jet ejectors is dependent on the steam pressure available to drive them. Greater steam flow rates are required at lower steam pressures. For the base case 50 MWe plant designed for constant brine temperature, steam pressures available to drive the ejectors remain constant at about 50 psia during the plant's lifetime. However, for the plants designed for the constant power output and constant brine flow rate operating modes, steam pressures decrease with declining brine temperature. At steam pressures below 50 psia, the second-stage steam jet ejector performs inefficiently. It then becomes more economical to use a mechanical vacuum pump in its place.

The conceptual design for the base case 50 MWe plant includes a single-stage steam jet ejector in series with a mechanical vacuum pump. For the plants modeled after the base case plant but designed for declining brine temperature, this combination performs well over the plant lifetime.

Hydrogen Sulfide Scrubber (T-4). Noncondensable gases (including air from the cooling water) vented from the second-stage vacuum pump pass through the hydrogen sulfide scrubber. The scrubber is designed to reduce the quantity of hydrogen sulfide in the vented gases to an environmentally acceptable level. The scrubbing medium is concentrated brine taken from the discharge of the second-stage flash tanks. After discharging from the scrubber, the brine is returned to the reinjection line. The scrubbing process employed in the unit has not been used commercially and must be tested. It may be necessary to add small quantities of alkali to the scrubbing medium to accelerate the absorption of hydrogen sulfide.

Brine Reinjection Pumps (P-1A, P-1B, P-1C). Unflashed brine from the second-stage flash tanks is pumped to reinjection wells. The discharge pressure of the pumps is 315 psia. They are vertical turbine, barrel-type pumps, with the barrel length designed to provide the required net positive suction head of the pump. Three pumps are provided, and each is sized for 50 percent capacity, so that, in the event of an outage of one pump, 100 percent pumping capacity will still be available. One of these pumps draws from each second-stage flash tank, and the third is a standby pump arranged in parallel to both. Level control valves for the second-stage flash tanks are located on the discharge side of the pumps to obtain constant pump suction conditions.

Circulating Water Pumps (P-2A, P-2B, P-2C). The three circulating water pumps are the principal pumps in the cooling water system. Three 33-percent pumps were provided, so that if there is an outage of one pump, the plant can still be operated at two-thirds capacity. Provision of a standby pump would have added significantly to plant investment costs and, considering the expected high pump reliability, was not justifiable.

Piping. Table 4-2 lists the major piping for the 50 MWe base case plant. Carbon steel was selected as the construction material for all of the major piping with the exception of the circulating water piping,

which is concrete. An adequate corrosion allowance was provided for the brine piping. This allowance was based on experience in the design and operation of desalination facilities, including the geothermal desalination pilot plants at East Mesa, California.

Table 4-2

MAJOR PIPING LIST — BASE CASE

Description	Diameter (in.)	Schedule or thickness (in.)	Length (ft)	Material
Brine Inlet	36	0.750	715	CS
Brine Reinjection	28	0.500	715	CS
High Pressure Steam (2 lines)	32	20	180	CS
Low Pressure Steam (4 lines)	32	20	320	CS
Circulating Water	72	1.50	735	concrete

Electrical, Instrumentation, and Control. In addition to mechanical equipment and piping, the base case plant conceptual design provides for the necessary electrical, instrumentation, and control systems.

The electrical equipment includes the main generator, 13.8 kV station switchgear, main transformer, 34.5 kV switchyard, auxiliary load transformer, and auxiliary load distribution system.

The hydrogen-cooled main generator is rated at 64,000 kVA, 0.9 PF and 13.8 kV. The generator is connected to the main transformer by a 13.8 kV, 3000 A, 1,000 MVA switchgear bus. The main transformer is rated 56 MVA, steps up the generator voltage to 34.5 kV and delivers power to the 34.5 kV switchyard.

The auxiliary load transformer, rated 10 MVA, draws power from the 13.8 kV station bus and steps it down to 4.16 kV for distribution to the auxiliary loads by the 4.16 kV switchgear and 4.16kV/480 V load centers.

4.3 PLANTS DESIGNED FOR CONSTANT POWER OUTPUT

4.3.1 Basis of Design

Curves of required brine flow rate for the 50 MWe units corresponding to the 50, 100, and 200 MWe plants designed for the constant power output operating mode are shown in Figure 4-7. These curves, which were developed using the temperature decline curves presented in Figure 3-3, formed the basis for the conceptual designs of the 50 MWe units.

4.3.2 Selection of Design Year

Curves of flash pressures versus time for all three plants were plotted from data generated by program GEOPRS and are presented in Figure 4-8. The first-stage flash pressure declines with time, while the second-stage flash pressure remains about constant with time.

Heat and mass balances for all of the 50 MWe units designed for constant power output were calculated at various years of plant operation using the flash pressures shown in Figure 4-8 and the brine temperature shown in Figure 3-3. Curves of steam mass flow rate and steam volumetric flow rate shown as functions of time in Figures 4-9 and 4-10, respectively, were plotted from the heat and mass balance data. As can be seen from the curves in Figure 4-10, the volumetric flow rates of low pressure steam are greatest in year 30, while the volumetric flow rates of high pressure steam are about constant during the plant lifetime. Therefore, flash tank size and steam piping size, which are affected by the volumetric flow rate of steam flashed in the tank, were based on year 30 in order to be large enough throughout the plant lifetime.

As can be seen in Figure 4-10, the volumetric flow rate of low pressure steam for the 50 MWe units comprising the 200 MWe plant designed for constant power output increases by more than 50 percent over 30 years. Since the unit is designed for year 30, the steam flow rate in year 1 will be about two-thirds of the design flow rate. This reduction in

Figure 4-7. BRINE FLOW RATES FOR 50 MWe UNITS, COMPRISING CONSTANT POWER OUTPUT PLANTS

Figure 4-8. FLASH PRESSURES FOR CONSTANT POWER OUTPUT PLANTS

Figure 4-9. MASS FLOW RATE OF STEAM FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT POWER OUTPUT OPERATING MODE

Figure 4-10. VOLUMETRIC FLOW RATE OF STEAM FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT POWER OUTPUT OPERATING MODE

flow rate will decrease the turbine expansion efficiency by at most one percent, which is considered negligible for the purposes of this study (Ref. 4-1). Constant expansion efficiency was assumed for calculations of performance.

Gross power output and circulating water flow rate were also calculated for each of the three 50 MWe units designed for constant power output. These data were plotted as functions of time and are shown in Figures 4-11 and 4-12. The flash pressures are different in year 1 for the three 50 MWe units, as shown in Figure 4-8. Different flash pressures produce different steam flow rates to the turbine, which require different circulating water flow rates in year 1 to condense the steam. The selection of a turbine-generator is based on gross power output, and the selection of other equipment (i.e., condenser, cooling tower, and pumps) and piping in the circulating water system is based on circulating water flow rate. It is clear from the curves in Figures 4-11 and 4-12 that the largest gross power outputs and circulating water flow rates occur in year 30. Additionally, from Figure 4-7, it can be seen that brine flow rate is greatest in year 30 for all three of the basic 50 MWe units. Since equipment such as flash tanks, pumps, condenser, cooling tower, and piping must be sized for the greatest flow rates, and the turbine-generator for the greatest gross power output, year 30 was used as the design basis for the plants employing the constant power output operating mode.

4.3.3 Conceptual Designs

Conceptual designs were completed for the three 50 MWe units that comprise the 50, 100, 200 MWe plants employing the constant power output operating mode. As discussed in Section 4.3.2, flow rates and auxiliary power requirements continually change throughout the life of the plants. To develop the bases for all the conceptual designs, heat and mass balance calculations for the three 50 MWe units using conditions in the design year (year 30) were completed. The resulting flow rates, pressures, and temperatures are listed in Table 4-3. In

Figure 4-11. GROSS POWER OUTPUT FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT NET POWER OUTPUT

Figure 4-12. CIRCULATING WATER FLOW RATE FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT POWER OUTPUT OPERATING MODE

Table 4-3

PROCESS FLOW RATES AND
THERMODYNAMIC STATE POINTS IN DESIGN YEAR
CONSTANT POWER OUTPUT⁽¹⁾

			Base Case 50 MWe Plant			Constant Power Output Operating Mode								
			Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)	50/50 MWe			50/100 MWe			50/200 MWe		
						Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)	Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)	Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)
STEAM SYSTEM														
Turbine														
High Pressure In	Vapor	0.852	46.5	280	0.878	41.8	275	0.836	41.8	273	0.728	41.8	273	
Low Pressure In	Vapor	0.588	15.8	219	0.600	16.7	223	0.680	16.7	222	0.880	16.7	222	
Low Pressure Out	Vapor	1.440	1.96	125	1.480	1.96	125	1.516	1.96	125	1.608	1.96	125	
Condenser														
In	Vapor	1.44	1.96	125	1.480	1.96	125	1.516	1.96	125	1.608	1.96	125	
Out	Liquid	50.7	1.96	115	52.2	1.96	115	54.3	1.96	115	57.0	1.96	115	
First-Stage Flash Tanks														
In	Liquid	10.12	115.0	338	12.0	115.0	338	13.40	71.0	304	17.0	47.0	277	
Out	Vapor	0.876	50.0	282	0.908	45.0	275	0.868	45.0	275	0.760	45.0	275	
Second-Stage Flash Tanks														
In	Liquid	9.22	50.0	282	11.12	45.0	275	12.60	45.0	275	16.28	45.0	275	
Out	Vapor	0.588	17.0	219	0.60	18.0	223	0.680	18.0	223	0.88	18.0	223	
BRINE SYSTEM														
First-Stage Flash Tanks														
In	Liquid	10.12	115.0	338	12.00	115.0	338	13.40	71.0	304	17.00	47.0	277	
Out	Liquid	9.22	50.0	282	11.12	45.0	275	12.60	45.0	275	16.28	45.0	275	
Second-Stage Flash Tanks														
In	Liquid	9.22	50.0	282	11.12	45.0	275	12.60	45.0	275	16.28	45.0	275	
Out	Liquid	8.64	17.0	219	10.58	18.0	222	11.90	18.0	223	15.40	18.0	223	
Brine Reinjection Pumps														
In	Liquid	8.69	17.0	219	10.60	18.0	222	12.00	18.0	223	15.40	18.0	223	
Out	Liquid	8.69	315.0	220	10.60	315.0	223	12.00	315.0	223	15.40	315.0	224	
COOLING WATER SYSTEM														
Condenser														
In	Liquid	48.3	14.7	87	49.8	14.7	87	51.0	14.7	87	54.3	14.7	87	
Out	Liquid	50.7	1.96	115	52.2	1.96	115	54.2	1.96	115	57.0	1.96	115	
Circulating Water Pumps														
In	Liquid	50.7	1.96	115	52.2	1.96	115	54.2	1.96	115	57.0	1.96	115	
Out	Liquid	50.7	52.8	115	52.2	52.8	115	54.2	52.8	115	57.0	52.8	115	
Cooling Towers														
In	Liquid	50.6	14.7	115	52.1	14.7	115	54.1	14.7	115	56.9	14.7	115	
Out	Liquid	49.2	14.7	87	50.7	14.7	87	52.6	14.7	87	55.3	14.7	87	

Note: (1) Design year is year 30.

A-1
CONDENSER
50 BHP
150 BHP

G-1
GENERATOR
5000 KW
(NET)

K-1A
TURBINE

K-1B
TURBINE

T-2A, 2B
2ND STAGE
FLASH TANKS

T-1A, 1B
1ST STAGE
FLASH TANKS

T-1A, 1B
1ST STAGE
FLASH TANKS

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 200 M STREET, WASHINGTON, D.C. 20540	PROJECT NO. 100-100
DESIGNED BY: [Signature]	DATE: 10-30-70
CHECKED BY: [Signature]	DATE: 10-30-70
APPROVED BY: [Signature]	DATE: 10-30-70

LEGEND
W - FLOW RATE, 10³ LB/HR
H - HOLDING VOLUME, 10³ LB
N - ENTHALPY, BTU/LB
A - ABSOLUTE PRESSURE, PSIA

NOTE
L TYP-4 INDICATES TYPICAL PLANTS

Figure 4-13

addition, Table 4-4 itemizes the auxiliary power requirements in the design year for the three 50 MWe units and the base case plant.

Figure 4-13 (Drawing M-301) illustrates the conceptual design of the 50 MWe unit for the 50 MWe plant designed for constant power output. Each of the three 50 MWe units consists of the same equipment items and has the same equipment arrangement as the base case plant described in Section 4.2. However, due to lower brine temperature in the design year (year 30), flow rates and, consequently, auxiliary power requirements are greater than for the base case plant, as can be seen by comparing Figures 4-5 and 4-13.

Table 4-4
AUXILIARY POWER REQUIREMENTS IN DESIGN YEAR
CONSTANT POWER OUTPUT(1)(2)

	50 MWe Plant Base Case (kWe)	50/50 (kWe)	50/100 (kWe)	50/200 (kWe)
Brine Reinjection Pumps	3,160	3,870	4,370	5,640
Circulating Water Pumps	2,850	2,930	3,000	3,190
Ejector Condenser Pumps	40	40	40	40
Scrubber Water Supply Pumps	15	15	15	15
Condenser Vacuum Holding Pumps	85	85	85	85
Cooling Tower Fans (Total)	1,150	1,190	1,220	1,300
Power from Other Services (Est.)	300	300	300	300
Total Auxiliary Power	7,600	8,430	9,030	10,570
Net Electrical Output	50,000	50,000	50,000	50,000
Gross Power Generated	57,600	58,430	59,030	60,570

Notes: (1) Design year is year 30.

(2) Electric motor efficiencies = 92%.

As discussed in Section 4.3.2, year 30 was used as the basis of design for the equipment and piping in the plants. The geothermal fluid temperature in year 30, which is different for all three plants, affects flow rates and gross power, and so accounts for different equipment

capacities in the plants. These differences are illustrated in Table 4-5, where the physical size and capacities of the major mechanical equipment for the base case plant and for the plants designed for constant power output are compared. The diameters of the major pipes are compared in Table 4-6.

It can be seen that except for the first-stage flash tanks, equipment size increases with plant capacity. The brine temperature in year 30, the design year, is lower for the larger plants, requiring, in general, greater flow rates and gross power outputs. However, a smaller high pressure steam volumetric flow rate is required by the larger plants as shown in Figure 4-10. Therefore, the size of the first-stage flash tanks and the high pressure steam piping decreases with plant capacity as shown in Tables 4-5 and 4-6.

Table 4-5
MAJOR MECHANICAL EQUIPMENT — CONSTANT POWER OUTPUT⁽¹⁾

Mechanical Equipment	50 MWe Plant Base Case	50/50 MWe	50/100 MWe	50/200 MWe
First-Stage Flash Tanks				
Length (with 11'3" dia.)(feet)	24	25	24	21
Second-Stage Flash Tanks				
Length (with 11'3" dia.)(feet)	25	25	28	36
Turbine				
Output (mech., kW _m)	58,200	59,000	59,600	61,200
Generator				
Output (gross, kWe)	57,600	58,400	59,000	60,600
Condenser				
Width (52'L x 34'W)(feet)	31	32	35	37
Cooling Water Pumps (hp)	1,180	1,200	1,260	1,330
Output (total)(gpm)	102,300	104,400	109,500	114,900
Brine Reinjection Pumps (hp)	1,950	2,380	2,350	2,480
Output (total) (gpm)	18,140	22,000	24,800 ⁽²⁾	32,000 ⁽³⁾
Cooling Tower				
Number of Cells	10	10	10	11
Total length (53'W)(Est.)	360	360	360	396
Cooling Water Flow (gpm)	102,100	104,000	109,200	114,800

Notes: (1) Design year is year 30.

(2) Includes 3,000 gpm pump installed in year 15.

(3) Includes 4,200 gpm pump installed in year 10, plus 4,800 gpm pump installed in year 20.

Table 4-6

DIAMETERS OF MAJOR PIPES — CONSTANT POWER OUTPUT

Pipe Category	50 MWe Plant Base Case	50/50 MWe	50/100 MWe	50/200 MWe
Pipe Diameter (inch)				
Brine, in	36	40	44	60
Brine, out	28	32	34	38
High Pressure Steam, in	32	34	34	32
Low Pressure Steam, in	32	32	32	36
Cooling Water, Main	72	72	72	72

The brine reinjection pumps for the 100 MWe and 200 MWe plants are the only equipment not designed for year 30 conditions. Because of the dramatic increase in flow rates between years 1 and 30, pumps selected for the flow rates in year 30 operate very far off the pump curve design point in year 1. This condition results in different pump discharge pressures and in reduced pump efficiencies in the early years of plant operation. Consequently, the brine reinjection pumps for the 100 and 200 MWe plants were designed for flow rates in earlier years, and the conceptual design provides for the installation of additional smaller pumps as needed in later years to accommodate the higher reinjection flow rates.

The difference in brine reinjection flow rates between years 1 and 30 for the 50 MWe plant is not as great as for the 100 MWe and 200 MWe plants. As a result, the pumps for the 50 MWe plant are designed for the year 30 flow rate and are throttled to obtain the lower flow rates required in earlier years. The slight reduction in pump efficiency that results from throttling is justified by the savings in the cost of installing an additional pump in later years.

The capacities of the major electrical equipment differ somewhat in the three 50 MWe units designed for constant net power output, as a result of different gross power outputs in the design year (year 30). These electrical capacities, which affect the cost of electrical equipment, are compared in Table 4-7.

4.4 PLANTS DESIGNED FOR CONSTANT BRINE FLOW RATE

4.4.1 Basis of Design

As described in Section 3.4, brine flow rates corresponding to various net power outputs in the first year of plant operation were used as input to the Chevron computer model of the Heber reservoir. A curve of declining brine temperature as a function of time was obtained as output from the reservoir model for each of the flow rates. Then, net power was calculated as a function of time for each of the temperature decline curves. These power curves were integrated with respect to time to obtain the total quantity of electric energy generated in thirty years for each curve. Finally, by interpolating between these power curves, a new curve was selected that represents the generation

Table 4-7

ELECTRICAL EQUIPMENT CAPACITIES CONSTANT POWER OUTPUT

	Base Case Plant	50/50 MWe	50/100 MWe	50/200 MWe
Main Generator (MVA)	64	65	66	67
13.8 kV Station Switchgear				
A	3,000	3,000	3,000	3,000
MVA	1,000	1,000	1,000	1,000
Main Transformer (MVA)	56	56	56	56
Auxiliary Load Transformer (MVA)	10	10	10.5	12.5

of 1,500 MWe-years of electric energy, the energy generated in 30 years by a 50 MWe plant designed for constant power output. This new curve illustrates a "50 MWe equivalent plant." The same procedure was used two more times to obtain curves of net power for the 50 MWe equivalent units comprising the 100 and 200 MWe plants designed for the constant brine flow rate operating mode. The conceptual designs of the three 50 MWe units were based on the resulting net power curves, as shown in Figure 4-14.

4.4.2 Selection of Design Year

Curves of flash pressure versus time for all three plants were plotted from data generated by program GEOPRS and are presented in Figure 4-15. It can be seen that the first- and second-stage flash pressures decline with time for all of the plants designed for constant brine flow rate.

Heat and mass balances for all of the 50 MWe units designed for constant brine flow rate were calculated at various years of plant operation using the flash pressures shown in Figure 4-15 and the brine temperatures shown in Figure 3-5. Curves of steam mass flow rate and steam volumetric flow rate, shown as functions of time in Figures 4-16 and 4-17, respectively, were plotted from the heat and mass balance data. As can be seen from the curves in Figure 4-17, the volumetric flow rates of low pressure steam are greatest in year 1, with the exception of the 200 MWe plant. For the 200 MWe plant, the volumetric flow rate of low pressure steam in year 30 is about the same as in year 1 and is maximum in these two years. The volumetric flow rates of high pressure steam are about constant during the plant lifetime. Therefore, flash tank size and steam piping size, which are affected by the volumetric flow rate of steam flashed in the tank, were based on year 1.

Figure 4-14. NET POWER OUTPUT VERSUS TIME FOR CONSTANT BRINE FLOW RATE OPERATING MODE

Figure 4-15. FLASH PRESSURES FOR CONSTANT BRINE FLOW RATE PLANTS

Figure 4-16. MASS FLOW RATE OF STEAM FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT BRINE FLOW RATE OPERATING MODE

Figure 4-17. VOLUMETRIC FLOW RATE OF STEAM FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT BRINE FLOW RATE OPERATING MODE

Gross power output and circulating water flow rate were also calculated for each of the three basic 50 MWe units designed for constant brine flow rate. These data were plotted as functions of time and are shown in Figures 4-18 and 4-19. The selection of a turbine-generator is based on gross power output, and the selection of equipment (i.e., condenser, cooling tower, and pumps) and piping in the circulating water system is based on the circulating water flow rate. It is clear from the curves in Figures 4-18 and 4-19 that the largest gross power outputs and circulating water flow rates occur in year 1. Since equipment such as flash tanks, pumps, condenser, cooling tower, and piping must be sized for the greatest flow rates, and the turbine-generator for the greatest gross power output, year 1 was used as the design basis for the plants employing the constant brine flow rate operating mode.

4.4.3. Conceptual Designs

Conceptual designs were completed for the three 50 MWe units that comprise the 50, 100, and 200 MWe plants employing the constant brine flow rate operating mode. As discussed in Section 4.4.2, steam and circulating water flow rates as well as net power output and auxiliary power requirements continually change throughout the life of the plants. To develop the bases for all the conceptual designs, heat and mass balance calculations for the three 50 MWe units using conditions in the design year (year 1) were completed. The resulting flow rates, pressures, and temperatures are listed in Table 4-8. In addition, Table 4-9 itemizes the auxiliary power requirements in the design year for the three 50 MWe units and the base case plant.

Figure 4-20 (Drawing M-302) is a flow diagram that illustrates the conceptual design of the 50 MWe unit for the 50 MWe plant designed for constant brine flow rate. Each of the three 50 MWe units consists of the same equipment items and has the same equipment arrangement as

Figure 4-18. GROSS POWER OUTPUT FOR 50 MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT BRINE FLOW RATE OPERATING MODE

Figure 4-19. CIRCULATING WATER FLOW RATE FOR MWe UNITS, COMPRISING PLANTS DESIGNED FOR CONSTANT BRINE FLOW RATE OPERATING MODE

the base case plant described in Section 4.2. However, the flow rates, and consequently auxiliary power requirements, are greater in the design year (year 1) than for the base case plant, as can be seen by comparing Figures 4-5 and 4-20.

As discussed in Section 4.4.2, year 1 was used as the basis of design for the equipment and piping in the plants. The net and gross power outputs in year 1, which are different for all three plants, account for different equipment capacities in the three plants. These differences are shown in Table 4-10, where the physical size and capacities of the major mechanical equipment for the base case plant and the plants designed for constant brine flow rate are compared. The diameters of the major pipes are compared in Table 4-11.

The capacities of the major electrical equipment differ somewhat in the three 50 MWe units designed for constant brine flow rate as a result of different net and gross power outputs in the design year (year 1). These electrical capacities, which affect the costs of electrical equipment, are compared in Table 4-12.

Table 4-9

AUXILIARY POWER REQUIREMENTS IN DESIGN YEAR
CONSTANT BRINE FLOW RATE (1) (2)

	50 MWe Plant Base Case (kWe)	50/50 (kWe)	50/100 (kWe)	50/200 (kWe)
Brine Reinjection Pumps	3,160	3,520	3,720	4,110
Circulating Water Pumps	2,850	3,160	3,350	3,700
Ejector Condenser Pumps	40	40	40	40
Scrubber Water Supply Pumps	15	15	15	15
Condenser Vacuum Holding Pumps	85	85	85	85
Cooling Tower Fans (Total)	1,150	1,280	1,360	1,500
Power from Other Services (Est.)	300	300	300	300
Total Auxiliary Power	7,600	8,400	8,870	9,750
Net Electrical Output	50,000	55,700	58,900	65,100
Gross Power Generated	57,600	64,100	67,770	74,850

Notes: (1) Design year is year 1.

(2) Electrical motor efficiencies = 92 percent.

Table 4-8

PROCESS FLOW RATES AND
THERMODYNAMIC STATE POINTS IN DESIGN YEAR
CONSTANT BRINE FLOW RATE⁽¹⁾

	Base Case 50 MWe Plant				Constant Brine Flow Rate Operating Mode								
					50/50 MWe			50/100 MWe			50/200 MWe		
	Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)		Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)	Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)	Flow Rate (10 ⁶ lb/hr)	Pressure (psia)	Temp. (°F)
STEAM SYSTEM													
Turbine													
High Pressure In	Vapor	0.852	46.5	280	0.948	46.5	280	1.002	46.5	280	1.108	46.5	280
Low Pressure In	Vapor	0.588	15.8	219	0.652	15.8	219	0.692	15.8	219	0.764	15.8	219
Low Pressure Out	Vapor	1.440	1.96	125	1.600	1.96	125	1.692	1.96	125	1.872	1.96	125
Condensers													
In	Vapor	1.440	1.96	125	1.600	1.96	125	1.692	1.96	125	1.872	1.96	125
Out	Liquid	50.7	1.96	115	56.4	1.96	116	59.7	1.96	116	66.0	1.96	116
First-Stage Flash Tanks													
In	Liquid	10.12	115.0	338	11.32	115.0	338	11.88	115.0	338	13.12	115.0	338
Out	Vapor	0.876	50.0	282	0.974	50.0	281	1.030	50.0	281	1.14	50.0	282
Second-Stage Flash Tanks													
In	Liquid	9.22	50.0	282	10.28	50.0	281	10.86	50.0	281	12.0	50.0	282
Out	Vapor	0.588	17.0	219	0.652	17.0	220	0.692	17.0	220	0.764	17.0	220
BRINE SYSTEM													
First-Stage Flash Tanks													
In	Liquid	10.12	115.0	338	11.32	115.0	338	11.88	115.0	338	13.12	115.0	338
Out	Liquid	9.22	50.0	282	10.28	50.0	281	10.86	50.0	281	12.0	50.0	282
Second-Stage Flash Tanks													
In	Liquid	9.22	50.0	282	10.28	50.0	281	10.86	50.0	281	12.0	50.0	282
Out	Liquid	8.64	17.0	219	9.62	17.0	219	10.24	17.0	219	11.2	17.0	220
Brine Reinjection Pumps													
In	Liquid	8.69	17.0	219	9.69	17.0	219	10.24	17.0	219	11.3	17.0	220
Out	Liquid	8.69	315.0	220	9.69	315.0	220	10.24	315.0	220	11.3	315.0	220
COOLING WATER SYSTEM													
Condenser													
In	Liquid	48.3	14.7	87	53.8	14.7	87	56.9	14.7	87	62.9	14.7	87
Out	Liquid	50.7	1.96	115	56.4	1.96	116	59.8	1.96	116	65.9	1.96	116
Circulating Water Pumps													
In	Liquid	50.7	1.96	115	56.4	1.96	116	59.8	1.96	116	65.9	1.96	116
Out	Liquid	50.7	52.8	115	56.4	52.8	116	59.8	52.8	116	65.9	52.8	116
Cooling Towers													
In	Liquid	50.6	14.7	115	56.3	14.7	116	59.7	14.7	116	65.8		116
Out	Liquid	49.2	14.7	87	54.7	14.7	87	58.1	14.7	87	64.0	14.7	87

Note: (1) Design year is year 1.

Figure 4-20

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 50/50 MW GEOTHERMAL POWER PLANT YERB, CALIFORNIA		
FLOW DIAGRAM CONSTANT BRINE RATE OPERATING MODE DESIGN YEAR 15 YEAR 1		
REV. NO.	DESCRIPTION	DATE
1	REVISED	11-30-78
2	REVISED	11-30-78

Table 4-10

MAJOR MECHANICAL EQUIPMENT — CONSTANT BRINE FLOW RATE⁽¹⁾

Mechanical Equipment	50 MWe Plant Base Case	50/50 MWe	50/100 MWe	50/200 MWe
First-Stage Flash Tanks Length (with 11'3" dia.)(feet)	24	26	27	31
Second-Stage Flash Tanks Length (with 11'3" dia.)(feet)	25	27	28	32
Turbine Output (mech., kW _m)	58,200	64,700	68,500	75,700
Generator Output (gross, kWe)	57,600	64,100	67,800	74,900
Condenser Width (52'L x 34'W)(feet)	31	35	37	43
Cooling Water Pumps (hp)	1,180	1,300	1,370	1,530
Output (total) (gpm)	102,300	111,600	119,400	132,900
Brine Reinjection Pumps (hp)	1,950	2,170	2,290	2,530
Output (total) (gpm)	18,140	20,200	21,200	23,400
Cooling Tower Number of Cells	10	11	11	13
Total length (53'W)(feet)	360	396	396	468
Cooling Water Flow (gpm)	102,100	111,000	119,000	132,800

Note: (1) Design year is year 1.

Table 4-11

DIAMETERS OF MAJOR PIPES
CONSTANT BRINE FLOW RATE

Pipe Category	50 MWe Plant Base Case	50/50 MWe	50/100 MWe	50/200 MWe
Pipe Diameter (inch)				
Brine, in	36	38	38	40
Brine, out	28	30	32	32
High Pressure Steam, in	32	34	34	36
Low Pressure Steam, in	32	34	34	36
Cooling Water, Main	72	72	72	78

Table 4-12

ELECTRICAL EQUIPMENT CAPACITIES
CONSTANT BRINE FLOW RATE

	Base Case Plant	50/50 MWe	50/100 MWe	50/200 MWe
Main Generator (MVA)	64	71	75	83
13.8 kV Station Switchgear				
A	3,000	3,000	4,000	4,000
MVA	1,000	1,000	1,500	1,500
Main Transformer (MVA)	56	62	65	72
Auxiliary Load Transformer (MVA)	10	10	10.5	12

4.5 COMPARISON OF PERFORMANCE

Although the 50 MWe base case plant was designed with the assumption that brine supply temperature would remain constant over its lifetime, calculations were performed to determine how 50, 100, and 200 MWe plants composed of 50 MWe base case units would perform if subject to declining brine temperature. The results of these performance calculations, which are given in Table 4-13, serve as a baseline to determine the magnitude of the benefits that may be derived by designing plants to accommodate the anticipated temperature decline.

The base case design also included an assumption of constant brine flow rate. Therefore, plants composed of these base case units would perform in the constant brine flow rate mode, if subject to declining brine temperature, as discussed above. The net power output from these base case plants would begin at 50, 100, and 200 MWe and decline as the brine temperature declines over their lifetimes. Averaged over the plant lifetime, the "equivalent" net power outputs for the 50 MWe units comprising the base case 50, 100, and 200 MWe plants would be 45.3 MWe, 43.4 MWe, and 39.9 MWe, respectively. This would represent a significant reduction in generating capacity.

It can be seen in Table 4-13, and also from the curves in Figure 4-7, that the brine flow rate for the 50 MWe units designed for constant power output increases between year 1 and year 30. The increase is greater for the larger plants because, as a result of reservoir draw-down, the brine temperature declines to a lower level and at a faster rate with larger plants (see Figure 3-7). The greatest increase in brine flow rate then is for the 200 MWe plant, which is seen to be 67 percent greater in year 30 than in year 1.

Table 4-13

PERFORMANCE DATA FOR
50 MWe UNITS

Year	Brine Flow (10 ⁶ lb/hr)		Net Power (MWe)		Specific Net Energy (Wh/lb Brine)	
	1	30	1	30	1	30
Base Case 50 MWe Plant, Constant Brine Temperature	10.1	10.1	50	50	4.95	4.95
Base Case 50 MWe Plant, Declining Brine Temperature, Constant Brine Flow Rate						
50 MWe Unit for 50 MWe (initial) Plant	10.1	10.1	50	42.6	4.95	4.22
50 MWe Unit for 100 MWe (initial) Plant	10.1	10.1	50	39.3	4.95	3.89
50 MWe Unit for 200 MWe (initial) Plant	10.1	10.1	50	33.9	4.95	3.36
Plants Designed for Constant Power Output						
50 MWe Unit for 50 MWe Plant	10.2	12.0	50	50	4.90	4.17
50 MWe Unit for 100 MWe Plant	10.2	13.4	50	50	4.90	3.73
50 MWe Unit for 200 MWe Plant	10.2	17.0	50	50	4.90	2.94
Plants Designed for Constant Brine Flow Rate						
50 MWe Unit for 50 MWe Plant	11.3	11.3	55.7	47.0	4.93	4.18
50 MWe Unit for 100 MWe Plant	11.9	11.9	58.9	45.3	4.95	3.81
50 MWe Unit for 200 MWe Plant	13.1	13.1	65.1	41.5	4.91	3.17

Further, Table 4-13 and Figure 4-14 show that net power for the 50 MWe equivalent units designed for constant brine flow rate begins in year 1 at a level higher than 50 MWe and finishes in year 30 at a level lower than 50 MWe. The change in net power from year 1 to year 30 is greater for the larger plants because (again) brine temperature declines more rapidly with larger plants. The 50 MWe units for the larger plants must therefore be designed to generate more net electric power in year 1, so with the decrease in power that occurs with temperature decline, they will still be "equivalent" 50 MWe units. For example, the 200 MWe plant generates 57 percent more power in year 1 than in year 30.

The trends over time for gross power output, which includes power for plant auxiliaries, are similar to the trends discussed above for net power output. Changes in gross power output over time are best observed in Figures 4-11 and 4-18. For the plants designed for constant power output, gross power increases between year 1 and year 30, and the increase is greater for the larger plants. These larger increases are due to the lower brine temperatures in year 30 (refer to temperature decline curves in Figure 3-3) and the larger brine and circulating water pumping requirements that result.

In year 1, specific net energies are nearly the same for all plants. The slight differences can be attributed to number rounding in the calculated data.

In year 30, however, the specific net energy for all the plants is lower than in year 1 because of the decline in brine temperature. It is lowest in year 30 for the 200 MWe plants.

In year 30, the specific net energy for the plants designed for constant brine flow rate are slightly higher than for the corresponding plants designed for constant power output. This better performance

can be attributed to slightly higher brine temperatures in year 30 for the plants designed for constant brine flow rate (refer to the temperature decline curves in Figure 3-5).

In the early years of plant operation, brine temperature declines more rapidly for plants designed for constant brine flow rate, and, as a consequence, specific net energy is slightly lower than for equivalent plants designed for constant power output. However, in the later years, the reverse happens, and specific net energy for plants designed for constant brine flow rate is slightly higher than for equivalent plants designed for constant power output. Therefore, the choice of operating mode makes relatively little difference on the overall performance of power plants over their lifetimes.

Specific net energies in year 30 are greatest for the base case plant designs that are subjected to declining brine temperature. However, these base case units, which are operated in the constant brine flow rate operating mode, are less than 50 MWe equivalent units, as discussed above. Consequently, they produce a slower rate of temperature decline than the 50 MWe equivalent units, and, hence, specific net energy is correspondingly higher in year 30.

Performance data for the plants (rather than for the 50 MWe units that comprise the plants) are compared in Table 4-14. The same trends discussed for the 50 MWe units occur for the plants. The increases in brine reinjection flow rates that result from increases in plant capacity and the correspondingly greater decline in brine temperature, parallel the increases in the brine production flow rate.

Table 4-14

PERFORMANCE DATA FOR PLANTS

	Net Power (MWe)		Brine Production Flow Rate (10 ⁶ lb/hr)		Brine ReInjection Flow Rate (10 ⁶ lb/hr)	
	1	30	1	30	1	30
Base Case 50 MWe Plant, Constant Brine Temperature	50	50	10.1	10.1	8.69	8.69
Base Case 50 MWe Plant, Constant Brine Flow Rate						
50 MWe (initial) Plant	50	42.6	10.1	10.1	8.69	8.69
100 MWe (initial) Plant	100	78.6	20.2	20.2	17.4	17.4
200 MWe (initial) Plant	200	135.6	40.4	40.4	34.8	34.8
Plants Designed for Constant Power Output						
50 MWe Plant	50	50	10.2	12.0	8.80	10.6
100 MWe Plant	100	100	20.4	26.8	17.6	24.0
200 MWe Plant	200	200	40.8	68.0	35.3	61.6
Plants Designed for Constant Brine Flow Rate						
50 MWe Unit Plant	55.7	47.0	11.3	11.3	9.69	9.69
100 MWe Unit Plant	117.8	90.6	23.8	23.8	20.4	20.4
200 MWe Unit Plant	260.8	165.0	52.4	52.4	45.2	45.2

Section 5

CAPITAL COST ESTIMATES OF POWER PLANTS

5.1 GENERAL

Conceptual capital cost estimates for ten commercial geothermal power plants at Heber, California, are included in this section. Each plant is comprised of one, two, or four 50 MWe (net) units, and each unit is designed specifically for the size and operating mode of the plant.

The estimates are based on the conceptual designs for the following:

- Base Case 50 MWe Plant
- Base Case with Constant Brine Flow Rate Operating Mode (declining brine temperature)
 - 50 MWe units of 50, 100, and 200 MWe (initial) plants
- Constant Power Output Operating Mode
 - 50 MWe units of 50, 100, and 200 MWe plants
- Constant Brine Flow Rate Operating Mode
 - 50 MWe units of 50, 100, and 200 MWe plants

Plant capital costs include the costs of all equipment, bulk materials, and site improvements within the plant site boundaries. The capital cost estimates are based on the drawings and equipment details shown in the plot plans, process flow diagrams, general arrangement drawings, and equipment lists in Sections 3 and 4.

5.2 PRICING

The estimates are at fourth quarter 1976 price and wage levels. No allowance has been made for escalation.

5.3 FIELD CONSTRUCTION COSTS

5.3.1 Direct Field Costs

The direct field construction costs of permanent plant equipment, bulk materials, and subcontracts were estimated on the following basis:

- Equipment. Suppliers' estimates were obtained for the major mechanical and electrical equipment, which include the following: turbine-generator, major pumps and drives, cooling tower, steam jet ejector, turbine crane, water treatment systems, air compressors, vacuum pump, instrumentation, control valves, transformers, and switchgear. The balance of the equipment was estimated using current prices from Bechtel sources.
- Bulk Material. Quantity takeoffs for concrete, steel, piping, and wiring have been made from the engineering drawings, and these quantities have been priced using current unit prices from Bechtel sources. Other bulk materials that would be shown on the final engineering drawings have been included as a percentage of the identified bulk materials.
- Subcontracts. Subcontract costs for equipment and bulk material normally installed by subcontractors have been estimated using current prices from Bechtel sources.
- Construction Labor. The direct construction labor costs for the installation of the plant equipment and material were estimated using recent productivity experience. An average labor wage rate was derived based on existing labor contracts and fringe benefits for the site using a craft mix similar to that experienced in a fossil-fired plant, adjusted for facility differences, plus an allowance of 5 percent for casual overtime and 1 percent for craft furnished supervision.

The wage rate used is \$17.00 per hour, which includes an allowance of \$1.65 per hour for travel and subsistence. Sufficient manual labor is assumed to be available in the project vicinity or to be attracted to the area by the travel allowance to complete the project within the schedule.

5.3.2 Indirect Field Costs

The indirect field costs are those items of construction cost that cannot be ascribed to any specific construction operation for the permanent facilities and are thus accounted separately. They were estimated by modifying the experience on fossil-fired plants to the geothermal plant at Heber. Indirect field costs are estimated as 65 percent of the direct construction labor costs and are included in the installation costs of the direct equipment and bulk materials.

The items covered by indirect field costs include temporary construction facilities, miscellaneous construction services, construction equipment and supplies, field office costs, preliminary checkout and acceptance testing, project insurance, taxes, and permits.

5.4 ENGINEERING SERVICES

The engineering services include engineering costs, other home office costs, and the fee. Engineering includes preliminary engineering, optimization studies, specifications, detail engineering, vendor-drawing review, site investigation, and support to vendors. Other home office costs include procurement, estimating and scheduling services, quality assurance, and project management. The fee is included as a function of the total project cost. The sum of these three categories falls into historically consistent percentages in the range of 10 to 20 percent, depending on the complexity of the project. For this study, a figure of 12 percent of field construction costs has been used as typical for a plant that, while new in concept, is not the first of its kind.

5.5 ALLOWANCE FOR UNCERTAINTY

Included in the estimate is an allowance for the uncertainty within the conceptual design in the quantity, pricing, or productivity that is under the control of the constructor and within the scope of the project as defined. This allowance is often referred to as the contingency allowance. Implicitly, the allowance will be expended during the design and construction of the project, and it cannot be considered as a source of funds for overruns or additions to the project scope.

5.6 QUALIFICATIONS

The following qualifications apply to the estimates:

- Carbon steel is specified for the piping that handles the geothermal brine.
- Geothermal vapors will be scrubbed to reduce hydrogen sulfide to an environmentally acceptable level.
- The base case constant brine flow rate operating mode plants are designed for an initial power production of 50, 100, or 200 MWe. As the well field temperature and pressure decline, the power output of these plants will also decline, eventually producing 43, 79, and 136 MWe, respectively, in the thirtieth year of plant operation.
- Due to the relatively low salinity of the brine at Heber and the success of recent reinjection tests at this site, it is assumed that brine treatment prior to reinjection will not be necessary.

5.7 EXCLUSIONS

The following items are excluded from the scope of the capital cost estimates for the power plants:

- Any special construction, such as widening and strengthening of existing roads
- Building of railroads
- Client engineering, financing, and other client costs⁽¹⁾
- Development costs of plant equipment such as the H₂S scrubber

- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽¹⁾
- Brine field production and reinjection wells; brine piping between the wells and the plant site fence⁽²⁾
- Power transmission lines beyond the plant site fence
- Allowance for interest during construction⁽³⁾
- Training of plant operators⁽¹⁾
- Plant startup and operation⁽¹⁾

Notes:

- (1) Included with Owners' Costs in the Cost of Electric Energy, Section 7.
- (2) Included in the Well Field Capital Cost, Section 6.
- (3) Included in the Cost of Electric Energy, Section 7.

5.8 ESTIMATE TABLES

The conceptual capital cost estimates shown in Tables 5-1, 5-2, and 5-3 include the total estimated costs of field construction, engineering services, and the allowance for uncertainty of each 50 MWe (net) unit conceptual design.

Tables 5-1 and 5-2 show a comparison of the costs of the base case 50 MWe plant and the 50 MWe units that comprise the 50, 100, and 200 MWe plants, designed for both the constant power output and the constant brine flow rate operating modes.* The tables include a breakdown of the field construction costs into mechanical equipment, piping

*The design and costs for the 50 MWe units of the base case plant and the base case constant brine flow rate operating mode plants (declining brine temperature) are identical. Only the costs for the 50 MWe unit of the base case plant are presented for brevity.

Table 5-1

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY
GEOHERMAL POWER PLANTS
HEBER, CALIFORNIA

HIGH TURBINE-GENERATOR COST

Installed Cost (\$1,000) (1)	Base Case (2)	Constant Output			Constant Flow Rate		
		50/50 MWe	50/100 MWe (3)	50/200 MWe (4)	50/50 MWe	50/100 MWe	50/200 MWe
Mechanical Equipment							
Turbine-Generator	10,160	10,370	10,475	10,755	11,370	12,020	13,265
Flash Tanks	320	400	405	440	420	430	470
Condensers	840	850	880	900	880	900	945
Cooling Towers	1,290	1,290	1,290	1,415	1,415	1,415	1,675
Pumps and Drives	2,070	2,250	2,260	2,325	2,190	2,250	2,395
Auxiliary Systems	620	645	650	660	640	650	665
Total	15,300	15,805	15,960	16,495	16,920	17,665	19,415
Piping and Instrumentation							
Piping, Valves, Insulation	3,410	3,600	3,720	4,175	3,540	3,545	3,685
Instrumentation and Controls	1,200	1,260	1,310	1,510	1,230	1,240	1,290
Total	4,610	4,860	5,030	5,685	4,770	4,785	4,975
Electrical							
Distribution Equipment	1,560	1,580	1,580	1,590	1,615	1,670	1,755
Cable and Raceways	1,060	1,085	1,110	1,145	1,085	1,095	1,140
Lighting, Miscellaneous	550	550	550	550	550	550	550
Total	3,170	3,215	3,240	3,285	3,250	3,315	3,445
Civil/Structural							
Turbine Building	1,950	1,950	1,960	1,970	1,980	2,000	2,010
Site Improvements	470	470	470	470	470	470	470
Concrete, Earthwork	1,370	1,370	1,370	1,435	1,440	1,445	1,595
Total	3,790	3,790	3,800	3,875	3,890	3,915	4,075
Field Construction Cost	26,870	27,670	28,030	29,340	28,830	29,680	31,910
Engineering Services	3,230	3,320	3,360	3,520	3,470	3,540	3,830
Allowance for Uncertainty	4,900	5,010	5,110	5,340	5,200	5,280	5,660
Total Installed Cost	35,000	36,000	36,500	38,200	37,500	38,500	41,400
Total Unit Cost, \$/kWe (Net)	700	720	730	764	750	770	828

Notes: (1) Fourth quarter 1976.

(2) The design and costs for the 50 MWe units of the base case plant and the base case constant brine flow rate operating mode plants (declining brine temperature) are identical. Only the costs for the 50 MWe unit of the base case plant are presented for brevity.

(3) 50/100 refers to a 50 MWe unit of a 100 MWe plant.

(4) 50/200 refers to a 50 MWe unit of a 200 MWe plant.

Table 5-2

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY
GEOTHERMAL POWER PLANTS
HEBER, CALIFORNIA

LOW TURBINE-GENERATOR COST

Installed Cost (\$1,000) ⁽¹⁾	Base Case ⁽³⁾	Constant Output			Constant Flow Rate		
		50/50 MWe	50/100 MWe	50/200 MWe	50/50 MWe	50/100 MWe	50/200 MWe
Mechanical Equipment ⁽²⁾							
Turbine-Generator	5,920	6,040	6,100	6,255	6,600	6,970	7,675
Other Mechanical	5,140	5,440	5,480	5,740	5,550	5,640	6,150
Piping and Instrumentation	4,610	4,860	5,030	5,685	4,770	4,785	4,975
Electrical	3,170	3,210	3,240	3,285	3,250	3,320	3,445
Civil/Structural	3,790	3,790	3,800	3,875	3,890	3,915	4,075
Field Construction Cost	22,630	23,340	23,650	24,840	24,060	24,630	26,320
Engineering Services	2,720	2,810	2,840	2,990	2,870	2,960	3,160
Allowance for Uncertainty	5,050	5,250	5,310	5,570	5,370	5,510	5,920
Total Installed Cost	30,400	31,400	31,800	33,400	32,300	33,100	35,400
Total Unit Cost, \$/kWe (Net)	608	628	636	668	646	662	708

Notes: (1) Fourth quarter 1976.

(2) All other accounts, except the turbine-generator, engineering, and allowance for uncertainty, are unchanged from the estimates with the high turbine-generator cost.

(3) The design and costs for the 50 MWe units of the base case plant and the base case constant brine flow rate operating mode plants (declining brine temperature) are identical. Only the costs for the 50 MWe unit of the base case plant are presented for brevity.

and instrumentation, electrical, and civil/structural categories. Cost estimates were obtained from turbine-generator manufacturers for geothermal steam turbine-generators. Because the turbine-generator is the major cost item in each plant, and a wide range of turbine-generator cost estimates were received, individual plant capital cost estimates were derived using both the high turbine-generator cost and the low turbine-generator cost. Based on gross output of the turbine-generator, the estimates ranged from \$160 to \$86 per kWe. The costs shown in Table 5-1 represent the high turbine-generator cost. Table 5-2 shows each estimate with the low turbine-generator cost.

Further detail of the base case 50 MWe plant estimate with the high turbine-generator cost is shown in Table 5-3. In this table, the total installed costs are separated into the three categories of equipment and materials, installation, and subcontracts.

5.9 COMPARISONS

Plant capital costs, for each of the ten plants with the high turbine-generator cost, are summarized in Table 5-1. Three trends may be noted in a comparison of the plant costs. First, the capital cost of the base case plant is less than the cost of the 50 MWe plants operating in the constant power output or the constant brine flow rate modes. The base case plant design assumes a constant well field temperature over the life of the plant. With a more realistic approach of declining brine temperature, the base case plant may be considered to be a plant operating in the constant brine flow rate mode. The average plant output over the 30-year plant life is approximately 45 MWe, and the corresponding unit cost will be \$778/MWe (net). This is slightly higher than the unit cost of \$750/MWe (net) for the 50 MWe plant operating in the constant brine flow rate mode. Economics of scale, by increasing plant size from 45 MWe to 50 MWe, are responsible for this difference.

Table 5-3

CONCEPTUAL CAPITAL COST ESTIMATE DETAIL — BASE CASE
50 MWe (NET) GEOTHERMAL POWER PLANT
HEBER, CALIFORNIA

Field Construction (\$1,000) (1)	Materials and Equipment	Installation	Subcontracts	Installed Cost
Mechanical Equipment				
Turbine-generator	9,370	790		10,160
Flash tanks	310	10		320
Condensers	290	480	70	840
Cooling tower		10	1,280	1,290
Pumps and drives	1,905	165		2,070
Auxiliary systems	425	95	100	620
Total	12,300	1,550	1,450	15,300
Piping and Instrumentation				
Piping, valves, and insulation	1,790	1,310	310	3,410
Instrumentation and controls	920	280		1,200
Total	2,710	1,590	310	4,610
Electrical				
Distribution Equipment	1,350	210		1,560
Cable and raceways	420	640		1,060
Lighting and miscellaneous	140	410		550
Total	1,910	1,260		3,170
Civil/Structural				
Turbine building	510	740	700	1,950
Site improvements	190	230	50	470
Concrete and earthwork	340	980	50	1,370
Total	1,040	1,950	800	3,790
Total Field Construction Cost	17,960	6,350	2,560	26,870

Note: (1) Fourth quarter 1976.

Second, the 50 MWe units for a particular operating mode increase in cost as the total plant sizes increase from 50 to 200 MWe. As the plant size increases, the final well field temperature, in year 30 of plant operation, decreases. Lower brine temperatures require higher brine flow rates, and therefore, larger and more expensive equipment. Economies of scale are not present in increasing the capacity to 100 and 200 MWe to offset costs due to decreased brine temperature because these plants are multiples of 50 MWe units.

Third, plants designed for the constant brine flow rate operating mode have greater capital cost than plants of the same capacity designed for the constant power output operating mode. The reason is that plant capital costs for designs requiring high power output in the first year of plant operation are higher than for designs that require increased brine flow rate in the final year of operation.

Section 6

CAPITAL COST ESTIMATES OF WELL FIELDS

6.1 GENERAL

Conceptual well field designs and capital cost estimates have been developed for each of the following ten commercial geothermal power plants at Heber, California:

- Base case 50 MWe Plant
- Base Case with Constant Brine Flow Rate Operating Mode (declining brine temperature)
— 50, 100, and 200 MWe (initial) plants
- Constant Power Output Operating Mode
— 50, 100, and 200 MWe plants
- Constant Brine Flow Rate Operating Mode
— 50, 100, and 200 MWe plants

Each plant is composed of one, two, or four 50 MWe (net) units designed specifically for the size and operating mode of the plant. The well field capital cost includes the cost of the production wells, reinjection wells, production well islands and associated equipment, reinjection well islands, and production and reinjection brine field piping.

6.2 LAYOUT OF WELL FIELD

The conceptual capital cost estimates are based on the following well field design information.

6.2.1 Production Wells

Production wells have 10-3/4-inch casings and are slant-drilled from production well islands to a nominal 6,000-foot depth. Drilling time

is approximately one month per well. The wells are naturally flowing at an assumed rate of 800,000 pounds per hour in the first year of operation. Brine temperature and pressure in the reservoir will decline during the life of the power plant. The declining brine pressure and the corresponding decrease in individual well flow rate, have been estimated by Chevron Resources, Inc. using a computer model of the Heber well field, including a well bore model. The additional number of wells required in years 2 through 30 of plant operation to compensate for the decline in individual well flow rate have been included for each plant design. For plants operating in the constant power output mode, further additional wells are added in years 2 through 30 to maintain the plant power output as the brine temperature declines. A schedule of production well drilling for years 1 through 30 of plant operation is shown in Table 6-1 for each of the 10 conceptual plant designs.

6.2.2 Reinjection Wells

Reinjection wells are slant drilled from reinjection well islands, also to a nominal 6,000-foot depth. A pumped reinjection well with a 10-3/4-inch casing is assumed to flow twice the mass flow of a production well, or approximately 1,600,000 pounds per hour of brine. Drilling time per well is approximately one month. Reinjection wells are added as necessary for the constant power output operating mode plants in years 2 through 30 to handle the increasing production well flows. For each of the ten plant designs, a schedule of reinjection wells, for years 1 through 30 of plant operation, is shown in Table 6-1.

6.2.3 Production Well Islands

Each 2-acre production well island includes the production wells (to a maximum of 24, including 4 spares, per island), sand settling tanks, cold brine dump pit for well startup, cold brine pump for the slow injection of cold brine from the pit into the production brine header,

Table 6-2

CAPITAL COST ESTIMATE OF WELL FIELD

Plant	Base Case	Base Case Constant Brine Flow Rate						Constant Power Output						Constant Brine Flow Rate					
		50 MWe		100 MWe		200 MWe		50 MWe		100 MWe		200 MWe		50 MWe		100 MWe		200 MWe	
Year Plant Operation	1-30	1	30	1	30	1	30	1	30	1	30	1	30	1	30	1	30	1	30
Number of Production Wells	13	13	15	26	31	52	73	13	17	26	40	51	102	14	16	30	86	65	91
Number of Reinjection Wells	6	6	6	12	12	24	24	6	7	12	15	23	40	6	6	13	13	29	29
Number of Production Islands	1	1	1	2	2	4	4	1	1	2	2	4	5	1	1	2	2	4	5
Number of Reinjection Islands	1	1	1	2	2	3	3	1	1	2	2	3	4	1	1	2	2	3	3
Installed Cost (\$ Million)																			
Surface Equipment	6.0	6.0	6.0	12.1	12.1	21.5	21.5	6.5	6.5	13.4	13.4	23.2	31.9	6.0	6.0	12.6	12.6	22.8	24.8
Wells	8.0	8.0	8.9	16.1	18.2	32.3	41.2	8.1	10.2	16.1	23.3	31.4	60.3	8.5	9.4	18.3	20.8	39.9	51.0
Field Construction Cost	14.0	14.0	14.9	28.2	30.3	53.8	62.7	14.6	16.7	29.5	36.7	54.6	92.2	14.5	15.4	30.9	33.4	62.7	75.8
Engineering Services	1.2	1.2	1.2	2.4	2.4	4.3	4.3	1.3	1.3	2.7	2.7	4.6	6.4	1.2	1.2	2.5	2.5	4.5	5.0
Allowance for Uncertainty	1.4	1.4	1.4	2.9	2.9	5.2	5.2	1.5	1.5	3.2	3.2	5.6	7.7	1.4	1.4	3.1	3.1	5.5	5.9
Total Installed Cost Fourth Quarter 1976	16.6	16.6	17.5	33.5	35.6	63.3	72.2	17.4	19.5	35.4	42.6	64.8	106.3	17.1	18.0	36.5	39.0	72.7	86.7

Note: The 20 percent allowance for spare production and reinjection wells used in the energy production cost analysis does not appear in this table.

an insulated brine header with valves, and associated wellhead equipment. For the constant power output operating mode plants, the sand settling tanks and brine header are sized for the maximum production brine flow anticipated from a particular island, in year 30 of plant operation.

Table 6-2 lists the number of production well islands needed for the various plants. Only two plants require that islands be added to the initial islands during the lifetime of the plants.

Each production island supplies the nearest 50 MWe unit, as shown in Figure 4-4. This figure shows the arrangement of the 200 MWe (initial) base case constant brine flow rate operating mode plant, with four 50 MWe (initial) units and four production well islands. The 200 MWe constant power output and 200 MWe constant brine flow rate plants require four production well islands in the first year of plant operation and one additional production island in years 19 and 18, respectively. The fifth production well island would be located midway between the two islands to the south of the power plants shown in Figure 4-4.

6.2.4 Reinjection Well Islands

The reinjection islands are located on a circle, with a radius of 2 miles from the power plant. Each 2-acre reinjection well island includes the reinjection wells (to a maximum of 12 wells, including 2 spares, per island) and an insulated brine header. For the constant power output plants, the brine header for a particular reinjection island is sized for the maximum brine flow rate in year 30 of plant operation. Table 6-2 lists the number of reinjection well islands needed for the various plants. Only one plant requires that an island be added to the initial ones during the plant's lifetime. One additional reinjection island is required for the 200 MWe constant power output plant in year 12 of plant operation.

6.2.5 Field Piping

Insulated production brine piping is above ground due to the short pipe runs and includes the piping from the production well island to the plant site fence. Field piping for a 20-well production island is a nominal 52-inch-diameter line. Reinjection brine piping is underground due to the two-mile length and includes the piping from the reinjection island to the plant site fence. As the spent brine temperature drops due to pipe heat loss, solids in the brine are likely to precipitate, plugging the reinjection line and wells. Therefore, the reinjection line must be insulated to maintain the reinjection temperature. Although the ground provides insulation, heat will be lost if the ground is moist unless the piping is insulated. A 36-inch line is required for the flow to a 10-well reinjection island. For the constant power output plants, the production and reinjection lines for a particular power plant are sized for the maximum brine flow rate in year 30 of plant operation. Two additional production lines and one additional reinjection line are required for the 200 MWe constant power output plant, and two additional production lines are required for the 200 MWe constant brine flow rate plant during each plant lifetime for the additional production and reinjection islands outlined above.

6.3 CAPITAL COST ESTIMATES

Well field plot plans, general arrangement sketches, piping lists, and equipment lists prepared for this study form the basis for the well field capital cost estimates.

6.3.1 Pricing

The estimates are at fourth quarter 1976 price and wage levels. No allowance has been made for future escalation.

6.3.2 Field Construction Costs

Direct Field Costs. The direct field construction costs of permanent plant equipment, bulk materials, and subcontracts were estimated on the following basis:

- Equipment and Bulk Materials. Suppliers' estimates were obtained for the pre-insulated production and

reinjection brine piping. Quantity takeoffs for concrete, piping, and excavation were made from the sketches, and these quantities, together with miscellaneous equipment and materials, were priced using current prices from Bechtel sources.

- Subcontracts. The production and reinjection wells are installed on a subcontract basis; each well costs approximately \$425,000 (Ref. 6-1). The subcontract price includes the cost of drilling, casing, wellhead equipment, directional work, well engineering, and an allowance for equipment failures and unforeseen problems.
- Construction Labor. The average wage rate of \$17.00 per hour and the value for labor productivity are the same for the well field capital cost estimate and the plant capital cost estimate; the labor mix for the installation of the well field equipment and piping will be similar to that of the power plant construction.

Indirect Field Costs. The well field cost estimate uses a value for the indirect field cost of 65 percent of direct construction labor cost. This is the same percentage used in the plant capital cost estimates.

6.3.3 Engineering Services

Engineering services have been included at 20 percent of the well field surface construction cost. Surface construction costs include the installed cost of the production and reinjection well islands, with their associated equipment, excluding the cost of the wells, plus the cost of the production and reinjection brine piping. Engineering services for the production and reinjection wells are performed by the subcontractor's drilling engineers. The costs for these services are included with the subcontract drilling cost.

6.3.4 Allowance for Uncertainty

Within the scope of each estimate an allowance for uncertainty in the quantity of material, pricing of equipment, or productivity of labor has been included. For the production and reinjection wells only, this allowance has been included in the subcontract drilling cost.

6.3.5 Qualifications

The following qualifications apply to each estimate:

- Carbon steel is specified for the production and reinjection geothermal brine piping.
- Due to an adequate well maintenance program, production and reinjection wells have an assumed service life of 30 years.

6.3.6 Exclusions

The following items are excluded from the well field capital cost estimates:

- Any special construction, such as widening and strengthening of existing roads
- Client engineering, financing, and other client costs⁽¹⁾
- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽¹⁾
- Allowance for interest during construction⁽¹⁾
- Training of well field operators; well field startup and operation⁽¹⁾

Notes:

- (1) Included with Owner's Costs in the Cost of Electric Energy, Section 7.

6.3.7 Estimate Tables

The total estimated capital costs, for years 1 and 30 of plant operation, of the well field surface equipment, production and reinjection wells, engineering services, and allowance for uncertainty for the base case 50 MWe plant, the 50, 100, and 200 MWe (initial) base case constant brine flow rate plants, and the 50, 100, and 200 MWe plants designed for the constant power output and the constant brine flow rate operating modes are shown in Table 6-2. Also shown for years 1 and 30 of plant operation are the number of production and reinjection wells and the number of production and reinjection well islands required for each plant.

6.4 COMPARISONS

Well field capital costs for each of the 10 plants are summarized in Table 6-2. Three general trends in the capital costs are apparent. First, for a particular operating mode, the unit cost, in \$/kWe (net), of the well field increases with increasing plant size. Increasing plant size will result in lower final well field brine temperatures. The lower brine temperatures will require increased brine flow to maintain the power output of the constant power output operating mode plants or to produce the high initial power from the constant brine flow rate operating mode plants. The increased well and surface equipment costs will reflect the increased brine flow requirements.

Second, for a plant of a given capacity, in the first year of plant operation, the well field costs for the constant power output plant will be less than the cost for the constant brine flow rate plant. In this first year, the plant operating in the constant power output mode will produce less power and, therefore, require less brine flow rate and well field equipment than the plant operating in the constant brine flow rate mode. By year 30, however, the well field costs for

the constant power output operating mode plant will be greater than the cost for the constant brine flow rate operating mode plant. In years 2 through 30 of a plant operating in the constant brine flow rate mode, additional wells and surface equipment are required only to compensate for the decline in individual well flow rate. Consequently, the increase in well field capital costs over the life of the plant is small. In contrast, for years 2 through 30 of plant operation in the constant power output mode, additional wells and surface equipment are required to compensate for the decline in individual well flow rate and the decline in brine temperature. Compensation for the decline in brine temperature is a considerable requirement, and well field capital costs increase substantially by year 30.

Third, in comparing the unit costs, in \$/kWe (average) of the base case plants operating with declining temperature in the constant brine flow rate mode and the plants designed for operation in the constant brine flow rate mode, economies of scale are present in the well field costs. For example, the 50 MWe (initial) base case plant operating in the constant brine flow rate mode has an average power output of approximately 45 MWe and a unit well field cost of \$370/kWe (average). The 50 MWe plant designed for operation in the constant brine flow rate mode produces an average of 50 MWe (net) and has a unit well field cost of \$343/kWe. The figures cited are for the first year of plant operation; however, the trend continues through the 30 years of plant operation.

Section 7

ENERGY PRODUCTION COST ESTIMATES

Energy production costs, expressed in mills per kilowatt-hour of net electric energy generation, are based on recovering over the commercial life of the geothermal power facilities:

- All invested capital
- A satisfactory return on invested capital
- All expenses
- Income and ad valorem taxes

In this study, energy production costs of both the power plant and the well field were estimated in arriving at a total bus bar cost for geothermal electric energy. The power plant costs include all costs associated with plant construction and operation. The well field costs include all costs associated with lease acquisition, resource exploration, field development, and production operations. Details of these costs and the approach used with each in this study are discussed in this section.

7.1 POWER PLANT ENERGY PRODUCTION COSTS

The cost of producing energy from the power plants in this study, exclusive of well field costs which are discussed in Section 7.2, comprise all costs associated with the construction and operation of the plants. The components of the power plant costs and the approach taken in estimating a levelized cost of energy production are discussed below.

7.1.1 Power Plant Cost Components

Power plant costs include those costs associated with:

- Capital investments including the cost of capital, depreciation, and income taxes
- Operating and maintenance expenses
- Plant insurance
- Administrative and general expenses
- Ad valorem taxes

Capital Investments. The capital investments required for the various geothermal power plants being considered in this study include the capital construction costs, as presented in Section 5 of this report, plus allowances for owner's costs (land, permits, etc.) and allowances for funds during construction (AFDC) (interest during construction, lenders' fees, etc). Owner's costs are assumed to be equivalent to 8 percent of the construction cost. AFDC is assumed to be 10 percent of the total of construction cost plus owner's costs, compounded annually from the cash flow center-of-gravity until the beginning of commercial operation. The cash flow center-of-gravity is assumed to occur after two-thirds of the construction schedule is complete based on experience with similarly sized construction projects.

Construction schedules were developed from experience gained in the design and construction of fossil-fired power plants, with adjustments for facility differences. Construction periods are estimated to be 40 months for the 50 MWe plants, 48 months for the 100 MWe plants, and 58 months for the 200 MWe plants for the base case, constant power output, or constant brine flow rate operating modes.

The total capital investment is capitalized over the commercial life of the power plant by applying a level annual fixed charge rate to the

sum of the construction cost, the owner's costs, and the AFDC. In this study, a factor of 14 percent per year was determined to be typical for an electric utility in the Imperial Valley region (Ref. 7-1). This factor accounts for the utility's regulated 10.8 percent return on investment, depreciation (i.e. capital recovery) over a 30-year plant life with no salvage value, and state and federal income taxes, including a 10 percent investment tax credit. Forty-nine percent of the utility's financing is assumed to be by bonded debt at a 9-1/2 percent tax deductible interest rate.

Ad valorem taxes and plant insurance, frequently included in utility level annual fixed charge rates, are considered separately in this study, as described below, and will increase the above 14 percent figure as shown in Section 7.1.2.

Operating and Maintenance Expenses. Annual operating and maintenance expenses for the geothermal power plants in this study are assumed to be 2 percent of the total capital cost of the plants. This estimating approach is based on recent utility experience with geothermal power plant operation and maintenance (Ref. 7-2), and a study of published annual operating and maintenance expenses for some 29 conventional fossil-fueled steam electric power plants (Ref. 7-3).

Insurance. Annual premiums for power plant insurance are estimated at 0.1 percent of the plants' total capital investment. This factor is based on recent utility experience with geothermal power facilities (Ref. 7-2).

Administrative and General Expenses. Annual administrative and general expenses that are incurred at the home office of the electric utility and that are apportioned to the geothermal power plant are assumed at 25 percent of the annual operating and maintenance expenses.

Ad Valorem Taxes. Annual ad valorem taxes for a power plant in the Heber region of the Imperial Valley are estimated to be about 2.5 percent of the capital cost (Ref. 7-4).

7.1.2 Power Plant Energy Production Cost Estimating Approach

The cost of energy produced from the power plant (excluding well field related "fuel" costs) includes investments capitalized over the life of the project and recurring annual costs expensed in the year incurred. As discussed in the preceding section, investments are capitalized in this study by applying a level annual fixed charge rate of 14 percent. This rate includes recovery of capital by straight line book depreciation, a 10.8 percent regulated utility's return on investment, and income taxes with a 10 percent investment tax credit provision. Recurring annual expenses (i.e., operating and maintenance, plant insurance, administrative and general expenses, and ad valorem taxes) amount to 5.1 percent of the plants' total capital cost. By this approach, total level annual production costs for the power plant, including capitalized investments, expenses, and taxes, amount to 19.1 percent of the plant's capital cost.

The power plant cost of energy is estimated by dividing the total level annual production costs (in mills) by the level annual net electric energy output of the power plant (in kilowatt-hours) at an 85 percent plant capacity factor (Ref. 7-5). With the approach taken in this study, the levelized cost of electric energy from the power plant, P_L , excluding "fuel" costs, may be expressed as:

$$P_L = \frac{0.191 \times C_P}{K_L}, \quad 7-1$$

where,

C_p = total capital cost of the power plant in mills
(including construction cost, owner's costs and
AFDC).

K_L = level annual power plant output in kilowatt-hours
at 85 percent capacity factor.

As demonstrated in this study, annual plant energy output declines over the life of the power plants operated under a constant brine flow mode due to declining reservoir temperature. In these cases, a level annual plant output, K_L , was derived by using the equation:

$$K_L = \frac{\sum_{n=1}^N (K_n \times PWF_n)}{\sum_{n=1}^N PWF_n}, \quad 7-2$$

where,

K_n = plant energy output at 85 percent capacity factor
in year n.

N = plant life in years.

PWF_n = present worth factor in year n given by:

$$PWF_r = \frac{1}{(1+r)^n},$$

where r is the 0.108 rate of return assumed
in computing the utility's level annual fixed
charge rate.

By levelizing the plant's annual energy output in this manner (using a 10.8 percent rate of return), it is on a consistent annual basis with the plant's level annual production costs. Thus, when the level annual production cost is divided by the level annual energy output, so derived, a level annual cost of energy in mills per kilowatt-hour for the power plant is obtained.

Tables showing the power plant energy production costs estimated in this study are presented in Section 7.3.

7.2 WELL FIELD ENERGY PRODUCTION COSTS

The cost of producing energy from the well fields, as developed in this study, comprises all costs of geothermal wells and surface facilities up to the fence line of the power plants. The components of the well field costs and the approach taken in estimating a levelized cost for energy production are discussed below.

7.2.1 Well Field Cost Components

Well field costs include those costs associated with:

- Reservoir exploration, confirmation, and engineering
- Lease acquisition and royalties
- Capital investments with a satisfactory rate of return
- Income taxes
- Operating expenses
- Maintenance expenses
- Administrative and general expenses
- Ad valorem taxes

Reservoir Exploration, Confirmation, and Engineering. Exploration and confirmation of a geothermal reservoir involves geological, geophysical, and geochemical surveys and evaluations required to locate and assess the quality and magnitude of a resource, including the drilling and evaluation of temperature gradient holes and confirmation wells. Information obtained through these procedures provides the basis for reservoir engineering, which determines the placement, schedule, and operating characteristics of production and reinjection wells.

For the low-risk financing case (at 10.8 percent DCF rate of return), reservoir exploration, confirmation, and engineering activities are assumed in this study to cost the well field operator \$2 million by the time commercial production begins. This cost is capitalized over the 30-year operating life of the field (Ref. 7-6, p. 63). Continued reservoir engineering activities during commercial operation are assumed to cost the field operator 5 percent of the field's gross production revenues each year. These annual costs are expensed in the year incurred.

For the risk-adjusted financing case, the costs of reservoir exploration, confirmation, and engineering activities in this study are assumed to be included in the 20 percent DCF rate of return.

Lease Acquisition and Royalties. Geothermal rights to previously undeveloped property are assumed in this study to be acquired by the well field operator through lease agreements with the land owner in return for basic royalty payments. Royalties are assumed to be 10 percent of the gross production revenues from the well field each year.

Capital Investments. The capital investments required for wells and well field surface facilities for each of the power plant capacities and operating modes considered in this study include the construction costs as presented in Section 6, plus an allowance for funds during construction (interest during construction, lender's fees, etc.), and an allowance for spare wells. AFDC is assumed to be 10 percent of the construction cost, compounded annually from the center-of-gravity of the construction cash flow schedule to the beginning of commercial operation. For the two-year well field construction period typically estimated in this study, the total AFDC amount comes to about 7 percent of the construction cost.

The spare well allowance assumed in this study is the cost of 20 percent more production and reinjection wells than are initially required in the first year of commercial operation of each plant. No spare

surface facilities are assumed. Dry hole costs are excluded from consideration because the Heber geothermal resource has been well explored and confirmed, and, as a result, unsuccessful drilling attempts are improbable.

Well field investments are capitalized over the life of the power plants in this study according to the methodology described in Section 7.2.2.

Income Taxes. Income taxes are estimated at an effective tax rate of 52.68 percent of gross income less expenses and capital depreciation. This is based on a 9 percent state tax rate and a 48 percent federal tax rate ($0.09 + 0.48(1.00 - 0.09) = 0.5268$). Accelerated, double declining balance switching to straight line, depreciation of capital assets is assumed for tax purposes (straight line depreciation, only, is assumed for book purposes). No depletion allowances or expensing of intangible well costs are assumed to be applicable to liquid dominated hydrothermal resources as are found in the Imperial Valley (Ref. 7-7).

As further discussed in Section 7.2.2, two alternative sources of financing for the geothermal well field investments are assumed in this study: low-risk utility capital and risk-adjusted energy company capital. With the utility-based alternative, 49 percent of the capital is assumed to be raised through debt financing at a 9-1/2 percent annual interest rate (Ref. 7-1). This interest expense is claimed as a tax deduction. With the energy company alternative, 100 percent equity financing is assumed, and no interest deduction is claimed in tax estimates.

An investment tax credit of 10 percent^{*} is assumed where applicable in all cases. In accordance with current United States tax law, the

* By tax law, investments made in the last 6 years of the field's useful life may receive 2/3 of the 10 percent credit; 1/3 of the credit is applied to investments made in the last 4 years, and no credit is allowed for those made in the last 2 years.

amount of credit claimed in any one year cannot exceed \$25,000 plus 50 percent of the tax liability over that amount. Unused credit, however, is carried over for up to seven subsequent years.

Operating Expenses. Annual operating expenses for the well field facilities include the following estimates:

- Foremen's and site manager's salaries and associated overhead at \$70,000 total per year.
- Field operators', roustabouts', electrical and instrumentation technicians', mechanics', mechanical engineers', and well engineers' salaries and associated overhead plus operating chemicals and other materials for a base case field of 13 production wells and associated reinjection wells at \$250,000 total per year.

For well fields having other than 13 production wells, the \$70,000 annual expense for foremen and the site manager remains unchanged, but a factor of

$$\left(\frac{\text{No. of Production Wells}}{13} \right)^{0.3}$$

is applied to the \$250,000 expense assumed for other salaries and operating materials.

Maintenance Expenses. Annual maintenance expenses for the well field facilities are assumed to include the following estimated expenditures:

- Production well maintenance at \$50,000 per well per year, including yearly downhole surveys and acidizations, reworking every four years, and miscellaneous maintenance supplies.
- Reinjection well maintenance at \$80,000 per well per year, including yearly downhole surveys and stimulations, reworking every two years, and miscellaneous maintenance supplies.

- Well field surface facilities maintenance at an annual cost equivalent to 0.5 percent of the capital cost of the surface facilities.

Administrative and General Expenses. Annual administrative and general expenses incurred by the well field operator that may be apportioned to the geothermal well field facilities are estimated to be 10 percent of the total annual operating and maintenance expenses of the well field.

Ad Valorem Taxes. Ad valorem taxes for the well field are assumed to be in the form of a production tax, a common practice in energy resource production (Ref. 7-6). In this study, ad valorem taxes are estimated to be 6 percent of the gross annual well field income.

7.2.2 Well Field Energy Production Cost Estimating Approach

The cost of energy produced from the well field includes investments that are capitalized over the life of the project and recurring annual costs that are expensed in the year incurred. Investments are capitalized in this study at two discounted cash flow (DCF) rates of return. The lower rate of return is 10.8 percent (Ref. 7-1), which is assumed to be representative of electric utility financing of the well field's capital requirements. The higher rate of return of 20 percent is assumed to be representative of energy company financing.

Utility financing at a regulated 10.8 percent rate of return demonstrates the low-risk nature of typical utility power plant investments. Energy company investments, on the other hand, require a higher, risk-adjusted rate of return to attract capital for resource exploration and development projects. It is probable that capital for geothermal well field developments will be obtained at a rate of return that is risk-adjusted and greater than the 10.8 percent assumed in this study as a lower limit.

The well field cost of energy is estimated by dividing the sum of level annual capitalized investment costs and operating costs for the well field (in mills) by the level annual net electric energy output of the power plant supported by that well field (in kilowatt-hours). This levelized cost of electric energy for the well field, W_L , may be represented by the relation:

$$W_L = (C_L + E_L)/K_L, \quad 7-3$$

where,

C_L = level annual cost of capital investments in mills (annual depreciation of principal plus return on remaining book value).

E_L = level annual expenses in mills (operating and maintenance costs, taxes, royalties, etc.).

K_L = level annual power plant output in kilowatt-hours.

Annual costs and energy output that vary over the life of a project are levelized to single annual amounts by the relation:

$$A_L = \frac{\sum_{n=1}^N (A_n \times PWF_n)}{\sum_{n=1}^N PWF_n}, \quad 7-4$$

where,

A_L = annual amount levelized over the project life.

N = project life in years.

A_n = amount in year n .

PWF_n = present worth factor in year n given by:

$$PWF_n = \frac{1}{(1 + r)^n},$$

where r is the annual DCF rate of return for the project.

The annual capital investment costs are estimated year-by-year using straight line depreciation (no salvage value is assumed for well field investments) to recover the investment principal plus a 10.8 percent or 20 percent return on the remaining book value of the investment (original investment less accumulated depreciation). Downstream investments, such as those required for additional production wells, are depreciated over the remaining project life. Thus, these investments are depreciated at a higher straight line rate than the initial investments.

Annual operating costs are expensed year-by-year. Annual electric energy output is the year-by-year product of the plant power output (in kilowatts), an 85 percent capacity factor, and 8,760 hours per year.

7.3 ENERGY PRODUCTION COST ESTIMATE RESULTS

7.3.1 Estimate Tables

Table 7-1 presents a summary of the energy production costs estimated for the several geothermal power plant capacities and operating modes investigated in this study. These results are based on an assumed 85 percent plant capacity factor, which is representative of recent experience at Geysers Geothermal Power Plants, and a power plant capital cost that includes the lower end of the range of turbine-generator price quotations received in the course of this study. Capacity factors other than 85 percent would produce an inversely proportional change in energy production costs.

Details of the costs shown in Table 7-1 are presented in Table 7-2 through 7-5. The detailed cost tables also include power plant energy production costs based on the higher end of the range of turbine-generator price quotations.

An analysis of the results of the energy production cost estimates is presented in Section 7.4 of this report.

Table 7-1

ENERGY PRODUCTION COSTS SUMMARY

	Level Output per Unit (MWe)	Power Plant Cost ⁽¹⁾ (Mills/kWh)	Well Field Cost (Mills/kWh)	Total Cost (Mills/kWh)
Base Case				
50/50 MWe at Constant Brine Temperature	50.0 —	18.9 —	16.3 @ 10.8% ⁽²⁾ 27.7 @ 20%	35.2 46.6
Basecase Design with Declining Temperature				
50/50 MWe	46.8 —	20.1 —	17.6 @ 10.8% 29.1 @ 20%	37.7 49.2
50/100 MWe	45.7 —	20.8 —	17.2 @ 10.8% 29.4 @ 20%	38.0 50.2
50/200 MWe	43.2 —	22.5 —	17.2 @ 10.8% 29.2 @ 20%	39.7 51.7
Constant Power Output				
50/50 MWe	50.0 —	19.5 —	17.3 @ 10.8% 28.9 @ 20%	36.8 48.4
50/100 MWe	50.0 —	19.9 —	17.1 @ 10.8% 29.8 @ 20%	37.0 49.7
50/200 MWe	50.0 —	21.4 —	17.0 @ 10.8% 28.8 @ 20%	38.4 50.2
Constant Brine Flow				
50/50 MWe	51.9 —	19.3 —	16.7 @ 10.8% 27.5 @ 20%	36.0 46.8
50/100 MWe	53.0 —	19.7 —	16.3 @ 10.8% 27.8 @ 20%	36.0 47.6
50/200 MWe	54.6 —	20.7 —	16.2 @ 10.8% 27.2 @ 20%	36.9 47.9

Notes: (1) Includes lower end of range of turbine-generator price quotations received.
(2) 10.8% is a low-risk, utility financed discounted cash flow rate of return;
20% is a risk-adjusted, energy company financed discounted cash flow rate
of return.

Table 7-2

ENERGY PRODUCTION COSTS DETAIL
BASE CASE: 50/50 MWe AT CONSTANT BRINE TEMPERATURE

Power Plant		
	Low ⁽¹⁾	High ⁽²⁾
Turbine-Generator Cost		
Levelized Power Output	50.0 MWe	50.0 MWe
Plant Capital Cost (Million \$) ⁽³⁾	36.7	42.3
Depreciation + Return + Income Taxes	13.8 mills/kWh	15.9 mills/kWh
Ad Valorem Taxes	2.5	2.8
Plant Insurance	0.1	0.1
Operation and Maintenance	2.0	2.3
Administration and General	0.5	0.6
Total Power Plant Costs (mills/kWh)	18.9	21.7
Well Field		
Financing Basis	Regulated Utility	Energy Company
Rate of Return	10.8%	20%
Book Depreciation	1.9 mills/kWh	1.8 mills/kWh
Return on Investment	4.7	8.9
Income Taxes	1.8 ⁽⁴⁾	8.0 ⁽⁵⁾
Ad Valorem Taxes	1.0	1.7
Operation	0.9	0.9
Maintenance	3.2	3.2
Administration and General	0.4	0.4
Royalties	1.6	2.8
Reservoir Development	0.8	0
Total Well Field Costs (mills/kWh)	16.3	27.7

Notes

- (1) Includes lower of turbine-generator price quotations received.
- (2) Includes higher of turbine-generator price quotations received.
- (3) Includes construction cost, owner's costs, and AFDC.
- (4) Includes deduction for bonded debt interest.
- (5) 100% equity financed (no interest deduction).

Table 7-3

ENERGY PRODUCTION COSTS DETAIL — BASE CASE WITH DECLINING TEMPERATURE
(85% capacity factor in all cases)

Power Plant	50/50 MWe		50/100 MWe		50/200 MWe	
Turbine-Generator Cost	Low ⁽¹⁾	High ⁽²⁾	Low	High	Low	High
Levelized Power Output	46.8 MWe	46.8 MWe	91.4 MWe	91.4 MWe	172.6 MWe	172.6 MWe
Plant Capital Cost (Million \$) ⁽³⁾	36.7	42.3	74.5	85.8	151.2	174.2
Depreciation + Return + Income Taxes	14.8 mills/kWh	17.0	15.3	17.6	16.5	19.0
Ad Valorem Taxes	2.6	3.0	2.7	3.2	2.9	3.4
Plant Insurance	0.1	0.1	0.1	0.1	0.1	0.1
Operation and Maintenance	2.1	2.4	2.2	2.5	2.4	2.7
Administration and General	0.5	0.6	0.5	0.6	0.6	0.7
Total Power Plant Costs (Mills/kWh)	20.1	23.1	20.8	24.0	22.5	25.9
Well Field						
Financing Basis	Regulated Utility	Energy Company	Regulated Utility	Energy Company	Regulated Utility	Energy Company
Rate of Return	10.8%	20%	10.8%	20%	10.8%	20%
Book Depreciation	2.1 mills/kWh	1.9	2.1	1.9	2.1	1.9
Return on Investment	5.0	9.4	5.0	9.7	5.0	9.6
Income Taxes	1.9 ⁽⁴⁾	8.5	1.9 ⁽⁴⁾	8.7 ⁽⁵⁾	1.9 ⁽⁴⁾	8.7
Ad Valorem Taxes	1.1	1.7	1.0	1.8	1.0	1.8
Operation	0.9	0.9	0.6	0.5	0.4	0.3
Maintenance	3.5	3.4	3.6	3.4	3.8	3.6
Administration and General	0.4	0.4	0.4	0.4	0.4	0.4
Royalties	1.8	2.9	1.7	3.0	1.7	2.9
Reservoir Development	0.9	0	0.9	0	0.9	0
Total Well Field Costs (Mills/kWh)	17.6	29.1	17.2	29.4	17.2	29.2

Notes:

- (1) Includes lower of turbine-generator price quotations received.
- (2) Includes higher of turbine-generator price quotations received.
- (3) Includes construction cost, owner's costs, and AFDC.
- (4) Includes deduction for bonded debt interest.
- (5) 100% equity financed (no interest deduction).

Table 7-4

**ENERGY PRODUCTION COSTS DETAIL — CONSTANT POWER OUTPUT
(85% capacity factor in all cases)**

Power Plant	50/50 MWe		50/100 MWe		50/200 MWe	
Turbine-Generator Cost Levelized Power Output Plant Capital Cost (Million \$) ⁽³⁾	Low ⁽¹⁾ 50.0 MWe 38.0	High ⁽²⁾ 50.0 MWe 43.6	Low 100.0 MWe 77.9	High 100.0 MWe 89.4	Low 200.0 MWe 166.5	High 200.0 MWe 190.4
Depreciation + Return + Income Taxes	14.3 mills/kWh	16.4	14.6	16.8	15.7	17.9
Ad Valorem Taxes	2.6	2.9	2.6	3.0	2.8	3.2
Plant Insurance	0.1	0.1	0.1	0.1	0.1	0.1
Operation and Maintenance	2.0	2.3	2.1	2.4	2.2	2.6
Administration and General	0.5	0.6	0.5	0.6	0.6	0.6
Total Power Plant Costs (Mills/kWh)	19.5	22.3	19.9	22.9	21.4	24.4
Well Field						
Financing Basis	Regulated Utility	Energy Company	Regulated Utility	Energy Company	Regulated Utility	Energy Company
Rate of Return	10.8%	20%	10.8%	20%	10.8%	20%
Book Depreciation	2.1 mills/kWh	1.9	2.1	2.0	2.2	1.9
Return on Investment	5.0	9.4	5.0	9.8	4.9	9.5
Income Taxes	1.9 ⁽⁴⁾	8.4 ⁽⁵⁾	1.9 ⁽⁴⁾	8.9 ⁽⁵⁾	1.8 ⁽⁴⁾	8.5 ⁽⁵⁾
Ad Valorem Taxes	1.0	1.7	1.0	1.8	1.0	1.7
Operation	0.9	0.9	0.5	0.5	0.3	0.3
Maintenance	3.4	3.3	3.6	3.4	3.8	3.6
Administration and General	0.4	0.4	0.4	0.4	0.4	0.4
Royalties	1.7	2.9	1.7	3.0	1.7	2.9
Reservoir Development	0	0	0.3	0	0.9	0
Total Well Field Costs (Mills/kWh)	17.3	28.9	17.1	29.8	17.0	28.8

Notes:

- (1) Includes lower of turbine-generator price quotations received.
- (2) Includes higher of turbine-generator price quotations received.
- (3) Includes construction cost, owner's costs, and AFDC.
- (4) Includes deduction for bonded debt interest.
- (5) 100% equity financed (no interest deduction).

Table 7-5

ENERGY PRODUCTION COSTS DETAIL — CONSTANT BRINE FLOW RATE
(85% capacity factor in all cases)

Power Plant	50/50 MWe		50/100 MWe		50/200 MWe	
Turbine-Generator Cost	Low ⁽¹⁾	High ⁽²⁾	Low	High	Low	High
Levelized Power Output	51.9 MWe	51.9 MWe	106.0 MWe	106.0 MWe	218.5 MWe	218.5 MWe
Plant Capital Cost (Million \$) ⁽³⁾	39.1	45.4	81.0	94.4	176.1	206.1
Depreciation + Return + Income Taxes	14.2 mills/kWh	16.5	14.4	16.7	15.2	17.7
Ad Valorem Taxes	2.5	2.9	2.6	3.0	2.7	3.2
Plant Insurance	0.1	0.1	0.1	0.1	0.1	0.1
Operation and Maintenance	2.0	2.4	2.1	2.4	2.2	2.5
Administration and General	0.5	0.6	0.5	0.6	0.5	0.6
Total Power Plant Costs (Mills/kWh)	19.3	22.5	19.7	22.8	20.7	24.1
Well Field						
Financing Basis	Regulated Utility	Energy Company	Regulated Utility	Energy Company	Regulated Utility	Energy Company
Rate of Return	10.8%	20%	10.8%	20%	10.8%	20%
Book Depreciation	2.0 mills/kWh	1.8	2.0	1.8	2.0	1.8
Return on Investment	4.8	8.9	4.7	9.1	4.6	8.9
Income Taxes	1.8 ⁽⁴⁾	8.0 ⁽⁵⁾	1.8 ⁽⁴⁾	8.2 ⁽⁵⁾	1.8 ⁽⁴⁾	8.0 ⁽⁵⁾
Ad Valorem Taxes	1.0	1.6	1.0	1.7	1.0	1.6
Operation	0.9	0.8	0.5	0.5	0.3	0.3
Maintenance	3.3	3.2	3.5	3.3	3.7	3.5
Administration and General	0.4	0.4	0.4	0.4	0.4	0.4
Royalties	1.7	2.8	1.6	2.8	1.6	2.7
Reservoir Development	0.8	0	0.8	0	0.8	0
Total Well Field Costs (Mills/kWh)	16.7	27.5	16.3	27.8	16.2	27.2

Notes:

- (1) Includes lower of turbine-generator price quotations received.
- (2) Includes higher of turbine-generator price quotations received.
- (3) Includes construction cost, owner's costs, and AFDC.
- (4) Includes deduction for bonded debt interest.
- (5) 100% equity financed (no interest deduction).

7.3.2 Comparative Analyses of Results

Tables 7-1 through 7-5 illustrate the influences of four factors on the cost of electric energy production:

- Declining temperature versus constant temperature in the base case plant
- Constant power output versus constant brine flow operating modes
- Differing plant capacities
- Low-risk utility financing versus risk-adjusted energy company financing

Declining versus Constant Brine Temperature. The cost of electric energy produced by the 50/50 MWe base case well field and power plant under constant brine temperature conditions increases 6 to 8 percent (depending on type of financing) when subject to declining brine temperature. This increase is due primarily to two factors. First plant power output drops with declining brine temperature, causing a drop in level power output of about 6 percent. This will cause an almost proportional increase in energy production costs expressed in mills per kilowatt-hour.

Secondly, production well flow drops with declining brine temperature, causing additional costs for wells in the later years of the project's life to maintain constant brine flow into the plant. The costs of these later wells will be discounted and will not influence energy production costs as much as the original wells, but these later wells will cause an increase in energy production costs to a minor degree.

Constant Power versus Constant Flow. The cost of electric energy produced by a 50/50 MWe well field and plant subject to declining brine temperature decreases 2 to 3 percent (depending on type of

financing) when the base case design is modified to a constant power output design. When modified to a constant brine flow design, the cost decrease is 4 to 6 percent (again depending on the type of financing). On this basis, the constant brine flow design appears to be slightly more economic than the constant power output design. The primary reasons for this are twofold. First, on a dollars per net levelized kilowatt basis, the constant flow power plant and well field capital cost is about 5 percent less than the base case capital cost, while the capital cost of the plant and well field designed for constant power is 1 to 3 percent^{*} less.

Secondly, although both the constant flow and constant power designs produce 50 MWe of power on the basis of an undiscounted, life-time arithmetic average, the power output in the early years of the constant flow design is higher than in later years. When levelized, the earlier high power is discounted less than the later low power, resulting in a net levelized power rating that is higher than 50 MWe. This causes lower energy production costs, expressed in mills per kilowatt-hour, for the well field and power plant in the constant flow case.

Differing Plant Capacities. In all plant cases, the energy production cost associated with the power plant increases as the plant capacity increases from 50 to 100 to 200 megawatts. This energy production cost increase is directly attributable to the increase in capital costs per kilowatt for the larger capacity plants as discussed in Section 5.9.

While plant capacity and power plant energy production costs both increase, the energy production cost associated with the well field

^{*}Three percent less in year 1; 1 percent less by year 30 due to increase in well field costs required to maintain constant power by increasing brine flow as brine temperature declines.

decreases slightly. This is primarily due to economies of scale gained with the larger plants because of more fully utilized well islands and main brine piping in the early, less discounted, years of well field operation.

Low-Risk versus Risk-Adjusted Financing. In all cases the energy production cost associated with the well field increases 65 to 75 percent when the basis of well field financing is changed from a low-risk regulated utility base to a risk-adjusted energy company base. This considerable increase is due to several factors. First, and of greatest significance, is the increase in DCF rate of return from 10.8 percent for the low-risk case, to 20 percent for the risk-adjusted case, as discussed in Section 7.2.2. This rate of return adjustment causes an increase in the well field gross revenue requirements and, therefore, related increases in income taxes, production (i.e., ad valorem) taxes, and royalties.

Secondly, for the low-risk utility based case a debt/equity ratio of 49/51 is assumed with a debt interest rate of 9-1/2 percent. This interest is tax deductible and serves to keep well field income taxes low. For the risk-adjusted energy company financing base, 100 percent equity financing is assumed and no tax deduction for interest can be claimed. This results in a significant increase in income taxes for the energy company base over the utility base.

Section 8

MULTISTAGE FLASH/BINARY PROCESS

The multistage flash/binary energy conversion process, using isopentane as the working fluid and geothermal brine as the heat source, was selected for the 50 MWe power plants at Niland, California. The conceptual design for the base case process without regeneration was developed during the previous study and is more fully described in the final report for that study (Ref. 1-2).

This section describes the site and its facilities, the multistage flash/binary process without regeneration, and the conceptual design of process equipment. A description of the multistage flash/binary process with regeneration is then developed to provide the basis for technical, environmental, and economic comparisons of the process with and without regeneration. These comparisons are developed in succeeding sections of the report. Regeneration is potentially attractive, because it recovers some of the waste heat from the turbine exhaust vapor to preheat the isopentane working fluid before it goes to the main geothermal heat transfer equipment.

8.1 NILAND SITE DESCRIPTION

8.1.1 Location

The Niland plant site lies within the Salton Sea Geothermal Field. The town of Niland is located in the Imperial Valley of California, approximately 4-1/2 miles east of the Salton Sea and 100 miles east

of San Diego. The plant site, located about eight miles southwest of Niland, is situated on agricultural land. An area of eight acres is required to accommodate all facilities within the site boundaries of the 50 MWe power plant.

8.1.2 Climatic Conditions

The Imperial Valley is a flat, arid, hot region lying mostly below sea level.

Climatic conditions used in this study are based on Yuma, Arizona, which is 64 miles southeast of the Niland site. Yuma conditions were used because the data are complete and are representative of the Niland area. Designs, from these conditions, are based on a prevailing summer wind from the southeast at 8.5 mph and temperatures of 111°F dry bulb and 79°F wet bulb. These temperatures are equaled or exceeded during only 1 percent of the hours of June through September of an average year. The mean daily dry bulb temperature ranges from 55°F in January to 93°F in July.

8.1.3 Brine Supply and Reinjection

The temperature, salinity, and noncondensable gas content of the geothermal brine from the existing wells varies over wide ranges. For design purposes, representative values are used.

The brine is assumed to have a downhole temperature of 550°F at saturated liquid conditions, to expand at constant enthalpy, and to be supplied to the power plant in the two-phase state at a temperature of 443°F and a pressure of 315 psia.

Brine delivered from the production wells experiences a drop in pressure as it rises in the well bore and a further drop due to line and valve losses. As a result, it flashes in the line and is supplied to the power plant as a two-phase mixture.

A composition of 250,000 ppm total dissolved solids is selected as a representative brine for the study with a noncondensable gas content of 0.5 percent by weight of the total brine flow.

Nearly all the brine supplied to the plant is returned to the field for reinjection. The cool brine leaves the plant as a liquid at a pressure of 315 psia, which is the nominal pressure needed for reinjection.

8.1.4 Water Supply

The plant site is bordered by both an irrigation water distribution canal and a drainage canal. Water pumped from the distribution canal can be used to supply the plant's fire water protection system and for general purpose domestic water, except drinking.

The Alamo River flows south to north about 2.8 miles east of the plant site. Water from this river can be piped to the plant site for cooling water makeup. The total dissolved solids content of the river water varies from 2,500 to 4,000 ppm, depending on the time of the year.

8.1.5 Electrical Transmission

The net power generated by the power plant can be supplied to the Imperial Irrigation District's network through a switching station that would be approximately 12 miles from the plant site.

8.2 DESCRIPTION OF MULTISTAGE FLASH/BINARY PROCESS

8.2.1 Without Regeneration

The multistage flash/binary process without regeneration is shown in the schematic diagram, Figure 8-1. The process converts heat energy stored in geothermal brine to electrical energy by using an organic working fluid, isopentane, as a heat transfer medium.

Figure 8-1. SCHEMATIC DIAGRAM: MULTISTAGE FLASH/BINARY ENERGY CONVERSION PROCESS WITHOUT REGENERATION

Figure 8-2. CYCLE DIAGRAM: MULTISTAGE FLASH/BINARY ENERGY CONVERSION PROCESS WITHOUT REGENERATION

The brine enters the separator-heat exchanger as a two-phase mixture of steam and brine. The steam passes through a mist eliminator and condenses on the exterior of heat exchange tubes, giving up its heat to the isopentane working fluid flowing inside the tubes. As the steam condensate falls back into the brine, it washes back the entrapped salt solution from the mist eliminator. Noncondensable gases, liberated from the geothermal fluid, are vented from the vessel.

Residual brine, diluted back to its initial concentration by the falling condensate, flows to the first flash stage of the multistage flash unit, which is at a lower pressure. A fraction of its water content flashes to steam, which again condenses on the tubes containing the organic working fluid. The brine continually decreases in temperature as the flashing-condensing process continues through all the stages. Finally, the cooled brine, still at its original concentration, is discharged from the last stage of the multistage flash unit and is pumped to the reinjection wells.

The isopentane flows through the separator-heat exchanger and the multistage flash unit, described above, countercurrent to the flow of flashing brine. This organic fluid, now converted to vapor, drives the turbine generator, and exhausts to the surface condenser. The organic vapor is desuperheated and condensed in the surface condenser, and the waste heat is transferred to cooling water, which circulates through a mechanical draft evaporative cooling tower. Condensate is then recycled through the organic heating circuit by the feed pumps. The cycle diagram of Figure 8-2 shows the process.

The multistage flash/binary process has the advantage of isolating the turbine and its controls from the corrosive and scale-forming constituents of the geothermal fluids. The process has a further advantage of employing proven commercial components in the brine circuit, which are all in wide use for the desalination of seawater.

8.2.2 With Regeneration

The multistage flash/binary energy conversion process with regeneration is a variation of the multistage flash/binary process without regeneration, discussed in the previous section. The potential improvement is in the organic fluid loop, where regenerators are installed before the multistage flash unit, as shown in Figure 8-3. This enables the organic fluid to be preheated by utilizing some of the turbine exhaust heat, which is otherwise rejected in the condenser to the cooling water.

Figure 8-4, the cycle diagram with regeneration, shows the state point (2) at the turbine exhaust to be in a superheated condition. The regenerator recovers the loss in heat content of the vapor between points (2) and (3) by transferring this heat to the liquid, which causes the state change from point (5) to (6). This results in the isopentane liquid being preheated before entering the multistage flash unit. Due to necessary terminal temperature differences in the heat exchange equipment, point (3) does not fall on the saturated vapor line.

To achieve high plant performance, the pressure drop through the vapor side of the regenerator must be minimized, thereby permitting the maximum expansion of the organic fluid in the turbine. In this regenerator design, an innovative and somewhat unconventional approach was taken to minimizing the pressure drop, with the turbine exhaust vapor being on the tube side of the regenerator rather than on the shell side.

Section 9

CONCEPTUAL DESIGNS OF POWER PLANTS

9.1 MULTISTAGE FLASH/BINARY PROCESS WITHOUT REGENERATION

The major equipment items, connecting piping, major valves, and controls of the multistage/binary process without regeneration are shown in Figure 9-1 (Drawing M-400) as developed in the initial study (Ref. 1-2). The process includes four main systems, the brine system, the isopentane system, the cooling system, and the electrical system. The equipment in these systems, subsequently described in this section, was either conceptually designed (the multistage flash units) or is commercially available (the cooling tower). Flow rates and thermodynamic state points at principal locations in the process are summarized in Table 9-1 for processes both with and without regeneration.

The function of the brine system is to extract the heat from the geothermal fluid, transfer this heat to the isopentane, and return the cooled brine for reinjection. The required brine flow rate is 3.6×10^6 pounds per hour with inlet conditions to the power plant of 315 psia and 443°F. Heat is transferred from the brine to the isopentane in the multistage flash units and the separator-heat exchanger at a rate of 1.21×10^9 Btu/hr. At the exit from the last stage of the multistage flash unit, the brine pressure is 3.04 psia. The reinjection pumps increase the pressure to 315 psia and return 3.57×10^6 pounds per hour of 154°F brine to the reinjection wells. The flow difference from inlet to outlet of the system is due to the loss of noncondensable gases. These gases are extracted from the heat transfer equipment, processed in a scrubber to remove hydrogen sulfide, and vented to the atmosphere.

Table 9-1

COMPARISON OF FLOW RATES AND
THERMODYNAMIC STATE POINTS
50MWe (NET) GEOTHERMAL POWER PLANT

Equipment	Without Regeneration	With Regeneration
Brine System		
Separator Heat Exchanger Inlet		
Temperature (°F)	443	443
Pressure (psia)	315	315
Flow (10 ⁶ lb/hr)	3.60	3.67
Rejection Pump Inlet		
Temperature (°F)	152	228
Pressure (psia)	3.04	15.6
Flow (10 ⁶ lb/hr)	3.57	3.63
Rejection Pump Outlet		
Temperature (°F)	154	229
Pressure (psia)	315	315
Flow (10 ⁶ lb/hr)	3.57	3.63
Isopentane System		
Condenser Outlet		
Temperature (°F)	113	114
Pressure (psia)	25.8	26.3
Flow (10 ⁶ lb/hr)	2 x 2.68	2 x 2.82
Main Feed Pump Outlet		
Temperature (°F)	117	117
Pressure (psia)	585	591
Flow (10 ⁶ lb/hr)	5.37	5.63
Regenerator Inlet		
Temperature (°F)		117
Pressure (psia)		591
Flow (10 ⁶ lb/hr)		5.63
Regenerator Outlet		
Temperature (°F)		191
Pressure (psia)		578
Flow (10 ⁶ lb/hr)		5.63
Multistage Flash Unit Inlet		
Temperature (°F)	117	191
Pressure (psia)	585	578
Flow (10 ⁶ lb/hr)	5.37	5.63
High Pressure Turbine Inlet		
Temperature (°F)	390	390
Pressure (psia)	550	550
Flow (10 ⁶ lb/hr)	5.37	5.63
Low Pressure Turbine Outlet		
Temperature (°F)	212	223
Pressure (psia)	28.8	32.8
Flow (10 ⁶ lb/hr)	2 x 2.28	2 x 2.41
Regenerator Inlet		
Temperature (°F)		223
Pressure (psia)		32.8
Flow (10 ⁶ lb/hr)		2 x 2.41
Regenerator Outlet		
Temperature (°F)		130
Pressure (psia)		28.8
Flow (10 ⁶ lb/hr)		2 x 2.82
Condenser Inlet		
Temperature (°F)	212	130
Pressure (psia)	28.8	28.8
Flow (10 ⁶ lb/hr)	2 x 2.68	2 x 2.82
Cooling Water System		
Circulating Water Pump		
Outlet Flow (10 ⁶ lb/hr)	44.2	37.2
Cooling Tower Inlet		
Flow (10 ⁶ lb/hr)	43.1	36.8
Makeup Flow (10 ⁶ lb/hr)	1.53	1.24
Blowdown Flow (10 ⁶ lb/hr)	0.51	0.41

Figure 9-1

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 30 MW (NET) GEOTHERMAL POWER PLANT NILES, CALIFORNIA		
FLOW DIAGRAM BASE CASE		
REV. NO. 1	DATE 11-76	BY C-101-1024
DESIGNER N-400	REVIEWER 0	APPROVER 0

The function of the isopentane system is to convert the heat energy obtained from the brine system to mechanical energy in the turbines. The system is a closed loop continually recycling 5.37×10^6 pounds per hour of the working fluid. Isopentane is drawn from a receiver tank and pressurized by motor driven low pressure feed pumps and the turbine driven main feed pump to 585 psia. The supercritical isopentane liquid flows through the tube side of the multistage flash units and separator-heat exchanger and is vaporized. The superheated vapor, with throttle conditions of 550 psia and 390°F , expands through the high pressure turbine and exhausts at 120 psia. It is further expanded, to 28.8 psia through the two back-to-back low pressure turbine stages and through the main feed pump turbine. Superheated vapor from the turbine exhausts enters the shell side of the condensers, where it is desuperheated and condensed. Condensation starts at 120°F and, due to the 3 psi pressure drop through the condenser, finishes at 113°F . Isopentane returns to the receiver tank by gravity, thus completing the isopentane loop.

The cooling system absorbs rejected heat from the isopentane system. The heat is absorbed by the cooling water when the isopentane vapor is desuperheated and condensed in the condensers. The heat is dissipated to the atmosphere by the cooling tower. Cooling water pumped by the circulating water pumps from the cooling tower flows at a rate of 43.6×10^6 pounds per hour through the tube side of the condensers. Heat is transferred to the water at a rate of 1.0×10^9 Btu/hr, with the water entering the condensers at 87°F and leaving at 110°F . The warm water returns to the cooling tower, where it is cooled by evaporation and reused. The evaporation process increases the concentration of dissolved solids in the cooling water by about three times. Therefore, the cooling tower water is continuously blown down with the wastewater being deaerated before being pumped, offsite, to a separate reinjection well.

9.1.1 Electrical System

The electrical system consists of the main generation system, the auxiliary system, and the plant/utility interface system. Its function is to supply power to the utility network during normal operation and to the plant auxiliary loads during normal operation as well as during startup and emergency operation. The main generator produces 55.65 MWe gross power output of which 5.65 MWe is for plant auxiliaries. Details of the auxiliary power requirements are given in Table 9-2, for the process both with and without regeneration. Electric motor efficiencies are assumed to be 92 percent. The 50 MWe (net) produced is transmitted to the Imperial Irrigation District 92 kV network through one or two switching stations approximately 12 miles from the plant site. Transmission lines connect the plant switchyard to the 92 kV system.

9.1.2 Facility Layout

The general arrangement of equipment is shown in Figure 9-2. This drawing shows the arrangement of buildings, major equipment, brine supply and reinjection lines, cooling water makeup lines, and electrical transmission lines. The turbine building houses the turbine-generator, its support equipment, and the main isopentane feed pump and drive. All other equipment is located adjacent to the building in the open.

A separate control building houses the electrical and control equipment. The main transformer and switchyard are located adjacent to the control building.

9.1.3 Equipment Description

The major items of equipment are described in the following paragraphs for the process without regeneration. Equipment numbers that are listed correspond to those in Figure 9-1. Standard power plant design practice was followed in the selection and arrangement of plant equipment. In

Table 9-2

AUXILIARY POWER REQUIREMENTS
50MWe(Net) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Equipment	Without Regeneration (kW)	With Regeneration (kW)
Brine Reinjection Pumps	1,230	1,190
Circulating Water Pumps	2,550	2,130
Low Pressure Feed Pumps	360	400
Makeup Water Pumps	110	90
Blowdown Rejection Pumps	200	160
Ejector Condenser Pumps	20	-
Scrubber Water Supply Pumps	10	10
Cooling Tower Fans	940	840
Power for Other Services (estimated)	230	230
Total Auxiliary Power	5,650	5,050
Net Electrical Output	50,000	50,000
Gross Power Generated	55,650	55,050

Figure 9-2. PLOT PLAN: 50 MWe (NET) MULTISTAGE FLASH/BINARY POWER PLANT WITHOUT REGENERATION, NILAND, CALIFORNIA

addition, the plant was designed to minimize auxiliary power requirements, without adding excessively to plant investment costs. Expected pump reliability was considered in determining if a standby pump was required for each application.

9.1.4 Brine System Equipment

Separator-Heat Exchanger (T-5). The two-phase geothermal fluid entering the plant is separated into brine and steam by the separator heat exchanger. In this vessel, the steam is condensed by transferring its heat to isopentane that is flowing through the tube bundle. The total quantity of heat transferred to the isopentane is 403×10^6 Btu/hr. The residual brine, diluted back to its initial concentration by the falling condensate, flows to the multistage flash units. Noncondensable gases, liberated from the geothermal fluids, are vented from the vessel.

The vessel is made of carbon steel with a 2-inch wall, of which $3/4$ inch is corrosion allowance. Titanium was selected for the tube bundle and the brine inlet distribution system. Other fittings are stainless steel.

Multistage Flash Section (T-1, T-2, T-3, and T-4). This section comprises four vessels, each consisting of 12 chambers or stages that successively reduce the brine pressure in 48 stages. At each stage steam flashes, rises, and condenses on the tube bundle, where it gives its heat at a rate of 806×10^6 Btu/hr to the isopentane flowing inside the tubes. Condensate falls back into the brine and is discharged to the next lower pressure stage where the flashing process is repeated. Noncondensable gases are cascaded and removed from the last stage by the jet ejector.

Each of the four vessels consists of a cylindrical shell of carbon steel, 2 inches thick, including a 3/4-inch corrosion allowance. The heat exchange tubes are titanium.

Brine Reinjection Pumps (P-1A, P-1B, and P-1C). Three, 50 percent capacity, vertical, turbine barrel type, centrifugal pumps take suction from the last stage of the multistage flash units at a pressure of 3.04 psia and discharge the cold brine at 315 psia to the line going to the reinjection wells. Stainless steel is used for both impellers and bowls to increase pump life and to reduce pump maintenance costs.

Jet Ejector and Condenser (J-1). Steam and noncondensable gases are removed at a rate of 2,890 pounds per hour from the last stage of the multistage flash units and from the cooling tower blowdown deaerator by a single-stage jet ejector. The ejector is driven by 29,300 pounds per hour of mixed steam and noncondensable gases that are vented from the separator-heat exchanger at a pressure of 315 psia. The steam is condensed in the direct contact ejector condenser, and the remaining noncondensable gases are vented to the atmosphere after passing through a hydrogen sulfide scrubber.

Hydrogen Sulfide Scrubber (T-8). About 18,000 pounds per hour of noncondensable gases, vented from the separator-heat exchanger, the multistage flash units, and the cooling tower blowdown deaerator pass through a hydrogen sulfide scrubber. There, the quantity of hydrogen sulfide is reduced to an environmentally acceptable level. The remaining gases, mainly carbon dioxide, are vented to the atmosphere.

9.1.5 Isopentane System Equipment

Main Turbine (K-1). The 76,000 shaft horsepower organic fluid turbine drives the main generator, which produces 55.65 MWe gross power output.

Of the generator output, 5.65 MWe is for plant auxiliaries. The turbine configuration selected is the radial inflow type and includes a single high pressure rotor and two back-to-back low pressure rotors all mounted in tandem and directly coupled to the generator. The expansion efficiency for the turbine was calculated by the manufacturer to be 85 percent. The turbine mechanical efficiency, which accounts for bearing and windage losses, is 97 percent. A pressurized lubrication system supplies filtered and cooled oil to the turbine generator bearings. Shaft seals have been developed to prevent leakage of organic fluid to the atmosphere.

Feed Pump Turbine (K-2). Since the drive for the main feed pump requires 6,610 horsepower, an auxiliary isopentane turbine is preferable to an electric motor drive for this large load. Consequently, the conceptual design includes a radial inflow feed pump turbine, operating over the same conditions as the low pressure stages of the main turbine. An organic turbine of this capacity maintains its best expansion efficiency (calculated by the manufacturer to be 84 percent) at speeds of about 10,000 rpm. Since the main feed pump operates at 3,100 rpm, a gearbox is provided for speed reduction. Lubrication and seals are similar to those of the main turbine.

Condensers (C-1 and C-2). The condensers are two identical horizontal shell and tube heat exchangers connected in parallel. Each condenser consists of a cylindrical shell 12 feet in diameter and 60 feet in length, fabricated from 3/4-inch-thick carbon steel. Each condenser has a heat transfer duty of 502×10^6 Btu/hr and uses copper nickel tubes.

Isopentane Receiver Tank (T-6). The receiver has a volume of 15,750 cubic feet, which is sufficient capacity to store the entire inventory of isopentane, as well as the volume lost during a system purge and

replacement plus an allowance for leakage. The buried receiver is coated with phenolic-epoxy (amine-cured), and cathodic protection is provided.

Isopentane Pumps. Pumps are required for three separate duties in the isopentane system. These are the low pressure feed pumps (P-2A, P-2B, P-2C, and P-2D), the main feed pump (P-9), and the auxiliary feed pump (P-10). There are four electric motor driven, 33 percent capacity, low pressure feed pumps. These pumps take suction below the liquid level in the receiver to give adequate operating net positive suction head. The main feed pump is driven, through a gearbox by the feed pump turbine. The pump is a two-stage horizontal centrifugal type and receives suction from the low pressure feed pumps at a pressure that meets its required net positive suction head under all operating conditions. An electric motor driven auxiliary feed pump is used during plant startup to produce enough isopentane flow, at the required pressure, to operate the main feed pump turbine.

9.1.6 Cooling System Equipment

Cooling Tower (E-1). The mechanical draft evaporative cooling tower consists of eight cells, each containing a fan and electric motor drive. The tower cools 43.7×10^6 pounds per hour of water from 110°F to 87°F at a design wet bulb temperature of 79°F and a design approach of 8°F .

Circulating Water Pumps (P-12A, P-12B, and P-12C). Three 33 percent capacity, vertical circulating water pumps are located in the cooling tower basin. In addition to the 43.6×10^6 pounds per hour of cooling water that is pumped to the main condensers, another 0.6×10^6 pounds per hour are required by the ejector condenser. Each pump has a capacity of 29,500 gpm at 122-foot head.

Deaerator (T-7). The vertical deaerator, 7 feet in diameter and 15 feet 6 inches long deaerates cooling tower blowdown before it is pumped to the reinjection wells.

Makeup Water Pumps (P-11A and P-11B). Two 100 percent capacity, vertical centrifugal type, makeup water pumps, each delivering 3,060 gpm of water at 132-foot head, are used. These pumps are mounted, offsite, in an intake structure located at the Alamo River.

9.1.7 Electrical System Equipment

Main Generator (G-1). The main generator is a three-phase, synchronous machine, totally enclosed, with water-air cooled windings. The generator is rated at 61,800 kVA at 0.9 PF, 13,800 volts with an efficiency of 97.5 percent. The rated speed is 3,600 rpm, and the frequency is 60 Hz. Excitation is by means of a shaft mounted exciter, and regulation is by means of a static voltage regulator.

9.2 MULTISTAGE FLASH/BINARY PROCESS WITH REGENERATION

The flow diagram for the multistage flash/binary energy conversion process with regeneration is shown in Figure 9-3 (Drawing M-401). The systems are similar to those described in Section 9.1 for the process without regeneration, but with the addition of two regenerators for heat recovery.

On the isopentane vapor side, the two regenerators are located in parallel between the two low pressure turbine exhausts and the two condensers. Isopentane liquid discharged from the main feed pump flows through the regenerators and then to the multistage flash units. In order to keep pressure drop on the vapor side to a minimum, these shell and tube heat exchangers are designed with the vapor in the tubes. Even with a minimum pressure drop on the vapor side, the turbine

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Figure 9-3

NOTE: 1. TYP. 2 INDICATES TYPICAL 2 PLACES

BECHTEL
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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
SUNNYSIDE GEOTHERMAL POWER PLANT
HILAND, CALIFORNIA

PROCESS WITH REGENERATION

JOB NO.	DESIGN NO.	REV.
67-76 C-30-104	M-401	0

expansion is reduced since its exhaust pressure is increased. Thus, to maintain the same net electrical power output of 50 MWe as the process without regeneration, the isopentane flow is increased by 70,000 pounds per hour. However, the isopentane on the liquid side is now preheated by 75°F, which reduces the heat that has to be transferred from the brine. Thus, there is a reduction in multistage flash and condenser heat transfer duty. The reduced duty not only decreases the size of the heat exchange equipment, but also decreases the size of the cooling system, because of the reduction in waste heat rejection. Table 9-3 lists the equipment sizes for the energy conversion processes both with and without regeneration.

9.2.1 Equipment Description

Most of the equipment for the multistage flash/binary process with regeneration is similar to that described in Section 9.1.3 for the process without regeneration. The major differences in equipment for the process with regeneration are described below.

Separator-Heat Exchanger (T-5). There is no change in the size of this unit, since the heat exchange duty has increased by less than 5 percent.

Multistage Flash Section (T-1, T-2, T-3, and T-4). With the addition of the regenerators, the quantity of heat that is transferred to the isopentane in the multistage flash units is reduced from 806×10^6 Btu/hr to 608×10^6 Btu/hr. Each of the four units is then reduced from 12 stages to 10 stages, and the length of each unit is reduced by 12 feet.

Jet Ejector and Condenser (J-1). This unit is not required, since the last stage of the multistage flash unit operates above atmospheric pressure allowing venting of the noncondensable gases.

Table 9-3
COMPARISON OF EQUIPMENT
50MWe(NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Equipment	Without Regeneration	With Regeneration
Regenerator		
Quantity	0	2
Type		Horizontal, Shell & Tube
Size		122" dia x 326" long
Shell		Carbon Steel, 3/4" thick
Tubes		
Type		3/4: (.083") C.S.
Number		13,468
Surface		71,822 sq. ft.
Jet Ejector Unit		
Jet Ejector	1	0
Ejector Condensor	1	0
Condenser Pump	2	0
Separator-Heat Exchnager		
Quantity	1	1
Size	10'dia x 60' long	10'dia x 60' long
Multistage Flash Unit		
Quantity(Units)	4	4
Stages/Unit	12	10
Size	9'dia x 60' long	9'dia x 52' long
Tube Surface	17,671 sq. ft.	14,844 sq. ft.
Condenser		
Quantity	2	2
Size	12' dia x 60' long	12' dia x 50' long
Tube Surface	149,000 sq. ft.	136,000 sq. ft.
Main Feed Pump Turbine		
Shaft Horsepower	6610	6920
Cooling Tower		
Cells	8	7
Overall Size	288' long x 53' wide	252' long x 53' wide
Circulating Water Pump		
Quantity	3	3
Capacity	29,500 gpm	24,800 gpm
Motor	1,050 hp	876 hp
Makeup Water Pump		
Quantity	2	2
Capacity	3,060 gpm	2,480 gpm
Motor	130 hp	107 hp
Blowdown Rejection Pump		
Quantity	2	2
Capacity	1,030 gpm	824 gpm
Motor	240 hp	189 hp
Makeup Water Pump		
Quantity	2	2
Capacity	3,060 gpm	2,480 gpm
Motor	130 hp	107 hp
Piping Diameter		
Main Cooling Water	60 inch	55 inch
Blowdown	8 inch	8 inch
Makeup	16 inch	14 inch
Isopentane to Turbine	36 inch	36 inch

Isopentane Condenser (C-1 and C-2). Due to the addition of the regenerators, the heat content of the vapor at entry to the condensers is reduced. Thus, each condenser duty is reduced from 503×10^6 Btu/hr to 420×10^6 Btu/hr. This reduces the required heat transfer surface area, and, as the isopentane vapor flow rate through the tubes is approximately the same, the overall length of each condenser is reduced by 10 feet.

Regenerators (R-1 and R-2). The regenerators are two identical shell and tube heat exchangers connected in parallel. Each regenerator consists of a cylindrical shell approximately 10 feet in diameter and 27 feet long, fabricated from 3/4-inch-thick carbon steel. Each regenerator has a heat transfer duty of 122×10^6 Btu/hr and uses carbon steel tubes. The isopentane vapor flows inside the tubes, and the isopentane liquid flows outside the tubes.

Circulating Water Pumps. Due to the reduced amount of heat transferred in the condensers, less cooling water has to be pumped in the cooling system. The three circulating water pumps are reduced in capacity by 4,700 gpm to 24,800 gpm each.

Cooling Tower. With less cooling water going to the cooling towers, the heat dissipation duty is reduced from $1,000 \times 10^6$ Btu/hr to 835×10^6 Btu/hr. This enables the tower to be reduced by one cell, decreasing the overall length by 36 feet to 252 feet.

9.2.2 Revised Facility Layout

The plot plan for the Niland plant (Figure 9-2) for the process without regeneration will require modification with the addition of regeneration. The cooling tower is reduced by one cell, which gives a smaller overall length. The two condensers, which are now smaller

in length, are moved further away from each side of the turbine building. This allows the two regenerators to be aligned parallel to the condensers between the turbine building and the condensers. The two turbine exhaust ducts exit the opposite sides of the turbine building connecting to the regenerators at one end; isopentane vapor flows to the other end. The vapor then flows to the mid-point of the condenser and after condensation flows, by gravity, to the isopentane receiver.

Section 10

COST ESTIMATES

10.1 CAPITAL COST ESTIMATES OF POWER PLANTS

10.1.1 General

Conceptual capital cost estimates for the two commercial 50 MWe (net) geothermal power plants, one with regeneration and the other without, described in the preceding two sections of this report, are included in this section. Plant capital costs include the cost of all equipment, bulk materials, and site improvements within the plant site boundaries.

A capital cost estimate of the base case plant design without regeneration was developed in the previous study (Ref 1-2) in terms of fourth quarter 1975 dollars. For the current study reported herein, this estimate was updated to fourth quarter 1976. This was accomplished by obtaining current turbine-generator price estimates and escalating all other plant costs by a factor for this period (approximately 7 percent) from the Hardy-Whitman Electric Light and Power Construction Index (Ref. 10-1).

As noted in Section 8, the design for the plant with regeneration is based on the plant design without regeneration. Suitable modifications have been made, as described in Section 9.2, to reflect the changes caused by the addition of the regenerators. The cost estimate for the plant with regeneration was prepared from revised equipment and piping lists from the plant without regeneration. Costs for electrical equipment, electrical bulk materials, and civil/structural work are taken directly from the escalated estimate for the plant without regeneration, since they are essentially alike for the two plants.

10.1.2 Pricing

Estimates for each plant are at fourth quarter 1976 price and wage levels, with all equipment and material considered purchased within the United States. No allowance has been made for escalation beyond the fourth quarter 1976.

10.1.3 Field Construction Costs

Direct Field Costs. The direct field construction costs of plant equipment, materials, and subcontracts were estimated on the following basis:

- Equipment. Suppliers' estimates were obtained for the following major mechanical and electrical equipment for each plant: turbine-generator, pumps and drives, separator-heat exchanger, multistage flash units, cooling tower, steam jet ejectors, turbine crane, air compressors, vacuum pump, cooling water treatment system, transformers, and switchgear. The balance of the equipment was estimated using fourth quarter 1975 prices from Bechtel sources escalated to fourth quarter 1976 price levels.
- Bulk Material. Quantity takeoffs for concrete, steel, piping, and wiring have been made from the engineering drawings. These quantities were priced using escalated fourth quarter 1975 unit prices from Bechtel sources; other bulk materials that would be shown on final engineering drawings have been included as a percentage of the identified bulk materials.
- Subcontracts. Subcontract costs for equipment and bulk material normally installed by subcontractors have been estimated using escalated fourth quarter 1975 prices from Bechtel sources.
- Construction Labor. The value for labor productivity used in the initial Niland estimate is also used for this study. The average labor wage rate has been escalated from the initial study and includes allowances for travel and subsistence, 5 percent for casual overtime and 1 percent for craft furnished supervision.

Indirect Field Costs. Indirect field costs are estimated as 65 percent of the direct construction labor costs. The items covered by indirect field costs include temporary construction facilities, miscellaneous construction services, construction equipment and supplies, field office costs, preliminary checkout and acceptance testing, project insurance, taxes, and permits. Indirect costs are included in the site improvement costs and installation costs of direct equipment and bulk materials.

10.1.4 Engineering Services

Engineering services include engineering costs, fee, and other home office costs. Other home office costs include procurement, estimating, scheduling, quality assurance, and project management. Engineering services have been estimated at 14 percent of the field construction cost.

10.1.5 Allowance for Uncertainty

Within the scope of each estimate, an allowance for uncertainty in the quantity of material, pricing of equipment, or productivity of labor has been included. This allowance is often referred to as a contingency allowance. The allowance will be expended during the project, and it cannot be considered as a source of funds for overruns or additions to the project scope.

10.1.6 Qualifications

The following qualifications apply to each estimate:

- Carbon steel is specified for all geothermal fluid piping.
- Existing hydrocarbon turbine design is adaptable to the process conditions of the conceptual design.

- Brine modification programs are being conducted at the San Diego Gas & Electric/ERDA Geothermal Loop Experimental Facility at Niland. It is assumed that these experiments in scale prevention will be successful and that brine treatment prior to reinjection will not be necessary.

10.1.7 Exclusions

The following items are excluded from the scope of the capital cost estimated for the power plants:

- Research and development associated with plant equipment and processes
- Any special construction, such as widening and strengthening of existing roads
- Building of railroads
- Client engineering, financing, and other client costs⁽¹⁾
- Development costs for plant equipment such as the H₂S scrubber
- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽¹⁾
- Brine field production and reinjection wells; brine piping between the wells and the plant site fence⁽²⁾
- Power transmission lines beyond the plant site fence
- Allowance for interest during construction⁽³⁾
- Training of plant operators⁽¹⁾
- Plant startup and operation⁽¹⁾

Notes:

- (1) Included with Owners' Costs in the Cost of Electric Energy, Section 10.3.
- (2) Included in the Well Field Capital Costs, Section 10.2.
- (3) Included in the Cost of Electric Energy, Section 10.3.

10.1.8 Estimate Tables

The total estimated costs of field construction, engineering services, and allowance for uncertainty for the Niland plants without regeneration and with regeneration are shown in Table 10-1. This table also shows a breakdown of the field construction costs into mechanical equipment, piping and instrumentation, electrical, and civil/structural costs. Further detail is provided in Tables 10-2 and 10-3, which separate for the plant without regeneration and with regeneration, respectively, the installed cost into the three categories of equipment and materials, installation, and subcontracts.

10.2 CAPITAL COST ESTIMATES OF WELL FIELD

10.2.1 General

Conceptual well field designs and capital cost estimates have been developed for commercial 50 MWe (net) geothermal power plants based on the multistage flash/binary process both with and without regeneration. However, because the production brine, reinjection brine, and cooling tower blowdown flow rates are essentially equal for each plant, one well field design and conceptual capital cost estimate is appropriate for both. The well field capital cost includes the cost of the production wells, reinjection wells, production well island and associated equipment, reinjection well island, and field piping for production brine, reinjection brine, and cooling tower blowdown.

10.2.2 Layout of Well Field

The conceptual estimate for each plant is based on the following well field design information:

- Production Wells. Production wells are slant-drilled from a production well island to a nominal 6,000-foot depth. A naturally flowing well with a 10-3/4-inch casing is assumed to flow 800,000 pounds per hour of brine. Drilling time is approximately one month per well. Five production wells and one spare are required for years 1 through 30 of plant operation.

Table 10-1

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

Field Construction	Installed Cost (\$1,000) ⁽¹⁾	
	Without Regeneration	With Regeneration
Mechanical Equipment		
Turbine-Generator	4,110	4,110
Multistage Flash Units	3,420	3,130
Separator-Heat Exchanger	1,310	1,310
Regenerators	—	1,010
Condensers	3,440	2,990 ⁽²⁾
Cooling Tower	1,220	1,010
Pumps and Drives	2,290	2,010
Auxiliary Systems	1,130	1,130
Total	16,920	16,700
Piping and Instrumentation		
Piping, Valves, and Insulation	4,310	4,325
Instrumentation and Controls	1,570	1,575
Total	5,880	5,900
Electrical		
Distribution Equipment	1,150	1,150
Cable and Raceways	1,320	1,320
Lighting and Miscellaneous	630	630
Total	3,100	3,100
Civil/Structural		
Turbine Building	670	670
Control Building	620	620
Site Improvements	510	510
Concrete and Earthwork	1,200	1,200
Total	3,000	3,000
Total Field Construction Cost	28,900	28,700
Engineering Services	4,000	4,000
Allowance for Uncertainty	6,600	6,500
Total Installed Cost	39,500	39,200

Notes: (1) Fourth quarter 1976.
(2) Jet ejector eliminated.

Table 10-2

CONCEPTUAL CAPITAL COST ESTIMATE DETAIL — PLANT WITHOUT REGENERATION
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Field Construction (\$1,000) ⁽¹⁾	Materials and Equipment	Installation	Subcontracts	Installed Cost
Mechanical Equipment				
Turbine-Generator	3,620	490		4,110
Multistage Flash Units	3,340	80		3,420
Separator-Heat Exchanger	1,190	120		1,310
Condensers	2,780	660		3,440
Cooling Towers		20	1,200	1,220
Pumps and Drives	2,100	190		2,290
Auxiliary Systems	850	170	110	1,130
Total	13,880	1,730	1,310	16,920
Piping and Instrumentation				
Piping, Valves, and Insulation	2,190	1,970	150	4,310
Instrumentation and Controls	790	780		1,570
Total	2,980	2,750	150	5,880
Electrical				
Distribution Equipment	1,050	100		1,150
Cable and Raceways	450	870		1,320
Lighting and Miscellaneous	150	480		630
Total	1,650	1,450		3,100
Civil/Structural				
Turbine Building	250	50	370	670
Control Building			620	620
Site Improvements	130	330	50	510
Concrete and Earthwork	280	920		1,200
Total	660	1,300	1,040	3,000
Total Field Construction Cost	19,170	7,230	2,500	28,900

Note: (1) Fourth quarter 1976.

Table 10-3

CONCEPTUAL CAPITAL COST ESTIMATE DETAIL — PLANT WITH REGENERATION
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Field Construction (\$1,000) ⁽¹⁾	Materials and Equipment	Installation	Subcontracts	Installed Cost
Mechanical Equipment				
Turbine-Generator	3,620	490		4,110
Multistage Flash Units	3,050	80		3,130
Separator-Heat Exchange	1,190	120		1,310
Regenerators	970	40		1,010
Condensers	2,460	530		2,990
Cooling Towers		20	990	1,010
Pumps and Drives	1,840	170		2,010
Auxiliary Systems	850	170	110	1,130
Total	13,980	1,620	1,100	16,700
Piping and Instrumentation				
Piping, Valves, and Insulation	2,200	1,965	160	4,325
Instrumentation and Controls	790	785		1,575
Total	2,990	2,750	160	5,900
Electrical				
Distribution Equipment	1,050	100		1,150
Cable and Raceways	450	870		1,320
Lighting and Miscellaneous	150	480		630
Total	1,650	1,450		3,100
Civil/Structural				
Turbine Building	250	50	370	670
Control Building			620	620
Site Improvements	130	330	50	510
Concrete and Earthwork	280	920		1,200
Total	660	1,300	1,040	3,000
Total Field Construction Cost	19,280	7,120	2,300	28,700

Note: (1) Fourth quarter 1976.

- Reinjection Wells. Reinjection wells are slant-drilled from a reinjection well island, also to a nominal 6,000-foot depth. A pumped reinjection well with a 10-3/4-inch casing is assumed to flow twice the mass flow of a production well, or approximately 1,600,000 pounds per hour of brine. Drilling time per well is approximately one month. Three brine reinjection wells, one spare and one cooling tower blowdown injection well are required for years 1 through 30 of plant operation. The cooling tower blowdown is not compatible with the reinjection brine, and a separate blowdown injection well is required.
- Production Well Island. One production well island, adjacent to the plant site boundary, is required for the production wells. The well island includes the production wells, sand settling tanks, cold brine dump pit for well startup, cold brine pump for the slow reinjection of cold brine from the pit into the production brine header, an insulated brine header with valves, and associated miscellaneous well equipment.
- Reinjection Well Island. The reinjection well island includes the reinjection wells, a cooling tower blowdown injection line, and an insulated reinjection brine header. One reinjection well island is required for either power plant and is located 2.0 miles from the plant site boundary.
- Field Piping. Insulated production brine piping is above ground due to the short pipe run from the production well island to the plant site fence. This piping for the five active well production island is a 20-inch line. The cooling tower blowdown line and insulated reinjection piping are placed side-by-side and run underground due to the two-mile lengths. The blowdown and reinjection field piping includes the piping from the plant site fence to the reinjection well island. A 20-inch line is required for the reinjection brine flow and an 8-inch line for the cooling tower blowdown flow.

The well field capital cost estimates are based on the plot plans, general arrangement sketches, piping lists, and equipment lists in Sections 8 and 9.

10.2.3 Capital Cost Estimates

The well field capital cost estimate is based on the well field design, which is described in Section 10.2.2

Pricing. The estimate is at fourth quarter 1976 price and wage levels. No allowance has been made for escalation.

Direct Field Construction Costs. The direct field construction costs of permanent plant equipment, bulk materials, and subcontracts were estimated on the following basis:

- Equipment and Bulk Materials. Suppliers' estimates were obtained for the preinsulated production and reinjection brine piping. Quantity takeoffs for concrete, piping, and excavation were made from the engineering drawings and sketches, and these quantities, together with miscellaneous equipment and materials, were priced using current prices from Bechtel sources.
- Subcontracts. The production and reinjection wells are installed on a subcontract basis; each production and reinjection well costs approximately \$425,000 (Ref. 6-1). The subcontract price includes the cost of drilling, casing, wellhead equipment, directional work, well engineering, and an allowance for equipment failures and unforeseen problems.
- Construction Labor. The average wage rate and the value for labor productivity are the same for the well field capital cost estimate and the plant capital cost estimate; the labor mix for the installation of the well field equipment and piping will be similar to the labor force for power plant construction.

Indirect Field Costs. The well field cost estimate uses a value for the indirect field costs of 65 percent of direct construction labor cost, which is the same as used in the plant capital cost estimates.

Engineering Services. Engineering services have been included at 20 percent of the wellfield surface construction cost. Surface construction costs include the installed cost of the production and reinjection well islands with their associated equipment, excluding the cost of the wells, plus the cost of piping for the production brine, reinjection brine, and cooling tower blowdown. Engineering services for the production and reinjection wells are performed by the subcontractor's drilling engineers and are included with the subcontract drilling cost.

Allowance for Uncertainty. Within the scope of each estimate, an allowance for uncertainty in the quantity of material, pricing of equipment, or productivity of labor has been included. For the production and reinjection wells only, this allowance has been included in the subcontract drilling cost.

Qualifications. The following qualifications apply to each estimate:

- Carbon steel is specified for the production and reinjection geothermal brine piping.
- Production and reinjection wells have a service life of 30 years.

Exclusions. The following items are excluded from the well field capital cost estimates:

- Any special construction, such as widening and strengthening of existing roads
- Client engineering, financing, and other client costs⁽¹⁾
- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽²⁾

- Allowance for interest during construction⁽¹⁾
- Training of well field operator; well field startup and operation⁽²⁾

Notes: (1) Included with Owner's Costs in the Cost of Electric Energy, Section 10.3.

(2) Included in the Cost of Electric Energy, Section 10.3.

Estimate Table. The total estimated costs of the well field surface equipment, production and reinjection wells, engineering services, and allowance for uncertainty for the 50 MWe power plants with and without regeneration, are shown in Table 10-4. Also shown are the number of production and reinjection wells and the number of production and reinjection islands required for each plant.

Table 10-4

CONCEPTUAL WELL FIELD CAPITAL COST ESTIMATE
(WITH AND WITHOUT REGENERATION)
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Number of Production Wells	5
Number of Reinjection Wells	4
Number of Production Well Islands	1
Number of Reinjection Well Islands	1
Installed Cost (\$1,000) ⁽¹⁾	
Surface Equipment	4,800
Production and Reinjection Wells	3,800
Field Construction Cost	8,600
Engineering Services	1,000
Allowance for Uncertainty	1,200
Total Installed Cost	10,800

Note: (1) Fourth quarter 1976.

expansion is reduced since its exhaust pressure is increased. Thus, to maintain the same net electrical power output of 50 MWe as the process without regeneration, the isopentane flow is increased by 70,000 pounds per hour. However, the isopentane on the liquid side is now preheated by 75°F, which reduces the heat that has to be transferred from the brine. Thus, there is a reduction in multistage flash and condenser heat transfer duty. The reduced duty not only decreases the size of the heat exchange equipment, but also decreases the size of the cooling system, because of the reduction in waste heat rejection. Table 9-3 lists the equipment sizes for the energy conversion processes both with and without regeneration.

9.2.1 Equipment Description

Most of the equipment for the multistage flash/binary process with regeneration is similar to that described in Section 9.1.3 for the process without regeneration. The major differences in equipment for the process with regeneration are described below.

Separator-Heat Exchanger (T-5). There is no change in the size of this unit, since the heat exchange duty has increased by less than 5 percent.

Multistage Flash Section (T-1, T-2, T-3, and T-4). With the addition of the regenerators, the quantity of heat that is transferred to the isopentane in the multistage flash units is reduced from 806×10^6 Btu/hr to 608×10^6 Btu/hr. Each of the four units is then reduced from 12 stages to 10 stages, and the length of each unit is reduced by 12 feet.

Jet Ejector and Condenser (J-1). This unit is not required, since the last stage of the multistage flash unit operates above atmospheric pressure allowing venting of the noncondensable gases.

Table 9-3
COMPARISON OF EQUIPMENT
50MWe(NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Equipment	Without Regeneration	With Regeneration
Regenerator		
Quantity	0	2
Type		Horizontal, Shell & Tube
Size		122" dia x 326" long
Shell		Carbon Steel, 3/4" thick
Tubes		
Type		3/4" (.083") C.S.
Number		13,468
Surface		71,822 sq. ft.
Jet Ejector Unit		
Jet Ejector	1	0
Ejector Condensor	1	0
Condenser Pump	2	0
Separator-Heat Exchanger		
Quantity	1	1
Size	10'dia x 60' long	10'dia x 60' long
Multistage Flash Unit		
Quantity(Units)	4	4
Stages/Unit	12	10
Size	9'dia x 60' long	9'dia x 52' long
Tube Surface	17,671 sq. ft.	14,844 sq. ft.
Condenser		
Quantity	2	2
Size	12' dia x 60' long	12' dia x 50' long
Tube Surface	149,000 sq. ft.	136,000 sq. ft.
Main Feed Pump Turbine		
Shaft Horsepower	6610	6920
Cooling Tower		
Cells	8	7
Overall Size	288' long x 53' wide	252' long x 53' wide
Circulating Water Pump		
Quantity	3	3
Capacity	29,500 gpm	24,800 gpm
Motor	1,050 hp	876 hp
Makeup Water Pump		
Quantity	2	2
Capacity	3,060 gpm	2,480 gpm
Motor	130 hp	107 hp
Blowdown Rejection Pump		
Quantity	2	2
Capacity	1,030 gpm	824 gpm
Motor	240 hp	189 hp
Makeup Water Pump		
Quantity	2	2
Capacity	3,060 gpm	2,480 gpm
Motor	130 hp	107 hp
Piping Diameter		
Main Cooling Water	60 inch	55 inch
Blowdown	8 inch	8 inch
Makeup	16 inch	14 inch
Isopentane to Turbine	36 inch	36 inch

Isopentane Condenser (C-1 and C-2). Due to the addition of the regenerators, the heat content of the vapor at entry to the condensers is reduced. Thus, each condenser duty is reduced from 503×10^6 Btu/hr to 420×10^6 Btu/hr. This reduces the required heat transfer surface area, and, as the isopentane vapor flow rate through the tubes is approximately the same, the overall length of each condenser is reduced by 10 feet.

Regenerators (R-1 and R-2). The regenerators are two identical shell and tube heat exchangers connected in parallel. Each regenerator consists of a cylindrical shell approximately 10 feet in diameter and 27 feet long, fabricated from 3/4-inch-thick carbon steel. Each regenerator has a heat transfer duty of 122×10^6 Btu/hr and uses carbon steel tubes. The isopentane vapor flows inside the tubes, and the isopentane liquid flows outside the tubes.

Circulating Water Pumps. Due to the reduced amount of heat transferred in the condensers, less cooling water has to be pumped in the cooling system. The three circulating water pumps are reduced in capacity by 4,700 gpm to 24,800 gpm each.

Cooling Tower. With less cooling water going to the cooling towers, the heat dissipation duty is reduced from $1,000 \times 10^6$ Btu/hr to 835×10^6 Btu/hr. This enables the tower to be reduced by one cell, decreasing the overall length by 36 feet to 252 feet.

9.2.2 Revised Facility Layout

The plot plan for the Niland plant (Figure 9-2) for the process without regeneration will require modification with the addition of regeneration. The cooling tower is reduced by one cell, which gives a smaller overall length. The two condensers, which are now smaller

in length, are moved further away from each side of the turbine building. This allows the two regenerators to be aligned parallel to the condensers between the turbine building and the condensers. The two turbine exhaust ducts exit the opposite sides of the turbine building connecting to the regenerators at one end; isopentane vapor flows to the other end. The vapor then flows to the mid-point of the condenser and after condensation flows, by gravity, to the isopentane receiver.

Section 10

COST ESTIMATES

10.1 CAPITAL COST ESTIMATES OF POWER PLANTS

10.1.1 General

Conceptual capital cost estimates for the two commercial 50 MWe (net) geothermal power plants, one with regeneration and the other without, described in the preceding two sections of this report, are included in this section. Plant capital costs include the cost of all equipment, bulk materials, and site improvements within the plant site boundaries.

A capital cost estimate of the base case plant design without regeneration was developed in the previous study (Ref 1-2) in terms of fourth quarter 1975 dollars. For the current study reported herein, this estimate was updated to fourth quarter 1976. This was accomplished by obtaining current turbine-generator price estimates and escalating all other plant costs by a factor for this period (approximately 7 percent) from the Hardy-Whitman Electric Light and Power Construction Index (Ref. 10-1).

As noted in Section 8, the design for the plant with regeneration is based on the plant design without regeneration. Suitable modifications have been made, as described in Section 9.2, to reflect the changes caused by the addition of the regenerators. The cost estimate for the plant with regeneration was prepared from revised equipment and piping lists from the plant without regeneration. Costs for electrical equipment, electrical bulk materials, and civil/structural work are taken directly from the escalated estimate for the plant without regeneration, since they are essentially alike for the two plants.

10.1.2 Pricing

Estimates for each plant are at fourth quarter 1976 price and wage levels, with all equipment and material considered purchased within the United States. No allowance has been made for escalation beyond the fourth quarter 1976.

10.1.3 Field Construction Costs

Direct Field Costs. The direct field construction costs of plant equipment, materials, and subcontracts were estimated on the following basis:

- Equipment. Suppliers' estimates were obtained for the following major mechanical and electrical equipment for each plant: turbine-generator, pumps and drives, separator-heat exchanger, multistage flash units, cooling tower, steam jet ejectors, turbine crane, air compressors, vacuum pump, cooling water treatment system, transformers, and switchgear. The balance of the equipment was estimated using fourth quarter 1975 prices from Bechtel sources escalated to fourth quarter 1976 price levels.
- Bulk Material. Quantity takeoffs for concrete, steel, piping, and wiring have been made from the engineering drawings. These quantities were priced using escalated fourth quarter 1975 unit prices from Bechtel sources; other bulk materials that would be shown on final engineering drawings have been included as a percentage of the identified bulk materials.
- Subcontracts. Subcontract costs for equipment and bulk material normally installed by subcontractors have been estimated using escalated fourth quarter 1975 prices from Bechtel sources.
- Construction Labor. The value for labor productivity used in the initial Niland estimate is also used for this study. The average labor wage rate has been escalated from the initial study and includes allowances for travel and subsistence, 5 percent for casual overtime and 1 percent for craft furnished supervision.

Indirect Field Costs. Indirect field costs are estimated as 65 percent of the direct construction labor costs. The items covered by indirect field costs include temporary construction facilities, miscellaneous construction services, construction equipment and supplies, field office costs, preliminary checkout and acceptance testing, project insurance, taxes, and permits. Indirect costs are included in the site improvement costs and installation costs of direct equipment and bulk materials.

10.1.4 Engineering Services

Engineering services include engineering costs, fee, and other home office costs. Other home office costs include procurement, estimating, scheduling, quality assurance, and project management. Engineering services have been estimated at 14 percent of the field construction cost.

10.1.5 Allowance for Uncertainty

Within the scope of each estimate, an allowance for uncertainty in the quantity of material, pricing of equipment, or productivity of labor has been included. This allowance is often referred to as a contingency allowance. The allowance will be expended during the project, and it cannot be considered as a source of funds for overruns or additions to the project scope.

10.1.6 Qualifications

The following qualifications apply to each estimate:

- Carbon steel is specified for all geothermal fluid piping.
- Existing hydrocarbon turbine design is adaptable to the process conditions of the conceptual design.

- Brine modification programs are being conducted at the San Diego Gas & Electric/ERDA Geothermal Loop Experimental Facility at Niland. It is assumed that these experiments in scale prevention will be successful and that brine treatment prior to reinjection will not be necessary.

10.1.7 Exclusions

The following items are excluded from the scope of the capital cost estimated for the power plants:

- Research and development associated with plant equipment and processes
- Any special construction, such as widening and strengthening of existing roads
- Building of railroads
- Client engineering, financing, and other client costs⁽¹⁾
- Development costs for plant equipment such as the H₂S scrubber
- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽¹⁾
- Brine field production and reinjection wells; brine piping between the wells and the plant site fence⁽²⁾
- Power transmission lines beyond the plant site fence
- Allowance for interest during construction⁽³⁾
- Training of plant operators⁽¹⁾
- Plant startup and operation⁽¹⁾

Notes:

- (1) Included with Owners' Costs in the Cost of Electric Energy, Section 10.3.
- (2) Included in the Well Field Capital Costs, Section 10.2.
- (3) Included in the Cost of Electric Energy, Section 10.3.

10.1.8 Estimate Tables

The total estimated costs of field construction, engineering services, and allowance for uncertainty for the Niland plants without regeneration and with regeneration are shown in Table 10-1. This table also shows a breakdown of the field construction costs into mechanical equipment, piping and instrumentation, electrical, and civil/structural costs. Further detail is provided in Tables 10-2 and 10-3, which separate for the plant without regeneration and with regeneration, respectively, the installed cost into the three categories of equipment and materials, installation, and subcontracts.

10.2 CAPITAL COST ESTIMATES OF WELL FIELD

10.2.1 General

Conceptual well field designs and capital cost estimates have been developed for commercial 50 MWe (net) geothermal power plants based on the multistage flash/binary process both with and without regeneration. However, because the production brine, reinjection brine, and cooling tower blowdown flow rates are essentially equal for each plant, one well field design and conceptual capital cost estimate is appropriate for both. The well field capital cost includes the cost of the production wells, reinjection wells, production well island and associated equipment, reinjection well island, and field piping for production brine, reinjection brine, and cooling tower blowdown.

10.2.2 Layout of Well Field

The conceptual estimate for each plant is based on the following well field design information:

- Production Wells. Production wells are slant-drilled from a production well island to a nominal 6,000-foot depth. A naturally flowing well with a 10-3/4-inch casing is assumed to flow 800,000 pounds per hour of brine. Drilling time is approximately one month per well. Five production wells and one spare are required for years 1 through 30 of plant operation.

Table 10-1

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

Field Construction	Installed Cost (\$1,000) ⁽¹⁾	
	Without Regeneration	With Regeneration
Mechanical Equipment		
Turbine-Generator	4,110	4,110
Multistage Flash Units	3,420	3,130
Separator-Heat Exchanger	1,310	1,310
Regenerators	—	1,010
Condensers	3,440	2,990 ⁽²⁾
Cooling Tower	1,220	1,010
Pumps and Drives	2,290	2,010
Auxiliary Systems	1,130	1,130
Total	16,920	16,700
Piping and Instrumentation		
Piping, Valves, and Insulation	4,310	4,325
Instrumentation and Controls	1,570	1,575
Total	5,880	5,900
Electrical		
Distribution Equipment	1,150	1,150
Cable and Raceways	1,320	1,320
Lighting and Miscellaneous	630	630
Total	3,100	3,100
Civil/Structural		
Turbine Building	670	670
Control Building	620	620
Site Improvements	510	510
Concrete and Earthwork	1,200	1,200
Total	3,000	3,000
Total Field Construction Cost	28,900	28,700
Engineering Services	4,000	4,000
Allowance for Uncertainty	6,600	6,500
Total Installed Cost	39,500	39,200

Notes: (1) Fourth quarter 1976.

(2) Jet ejector eliminated.

Table 10-2

CONCEPTUAL CAPITAL COST ESTIMATE DETAIL — PLANT WITHOUT REGENERATION
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Field Construction (\$1,000) ⁽¹⁾	Materials and Equipment	Installation	Subcontracts	Installed Cost
Mechanical Equipment				
Turbine-Generator	3,620	490		4,110
Multistage Flash Units	3,340	80		3,420
Separator-Heat Exchanger	1,190	120		1,310
Condensers	2,780	660		3,440
Cooling Towers		20	1,200	1,220
Pumps and Drives	2,100	190		2,290
Auxiliary Systems	850	170	110	1,130
Total	13,880	1,730	1,310	16,920
Piping and Instrumentation				
Piping, Valves, and Insulation	2,190	1,970	150	4,310
Instrumentation and Controls	790	780		1,570
Total	2,980	2,750	150	5,880
Electrical				
Distribution Equipment	1,050	100		1,150
Cable and Raceways	450	870		1,320
Lighting and Miscellaneous	150	480		630
Total	1,650	1,450		3,100
Civil/Structural				
Turbine Building	250	50	370	670
Control Building			620	620
Site Improvements	130	330	50	510
Concrete and Earthwork	280	920		1,200
Total	660	1,300	1,040	3,000
Total Field Construction Cost	19,170	7,230	2,500	28,900

Note: (1) Fourth quarter 1976.

Table 10-3

CONCEPTUAL CAPITAL COST ESTIMATE DETAIL — PLANT WITH REGENERATION
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Field Construction (\$1,000) ⁽¹⁾	Materials and Equipment	Installation	Subcontracts	Installed Cost
Mechanical Equipment				
Turbine-Generator	3,620	490		4,110
Multistage Flash Units	3,050	80		3,130
Separator-Heat Exchange	1,190	120		1,310
Regenerators	970	40		1,010
Condensers	2,460	530		2,990
Cooling Towers		20	990	1,010
Pumps and Drives	1,840	170		2,010
Auxiliary Systems	850	170	110	1,130
Total	13,980	1,620	1,100	16,700
Piping and Instrumentation				
Piping, Valves, and Insulation	2,200	1,965	160	4,325
Instrumentation and Controls	790	785		1,575
Total	2,990	2,750	160	5,900
Electrical				
Distribution Equipment	1,050	100		1,150
Cable and Raceways	450	870		1,320
Lighting and Miscellaneous	150	480		630
Total	1,650	1,450		3,100
Civil/Structural				
Turbine Building	250	50	370	670
Control Building			620	620
Site Improvements	130	330	50	510
Concrete and Earthwork	280	920		1,200
Total	660	1,300	1,040	3,000
Total Field Construction Cost	19,280	7,120	2,300	28,700

Note: (1) Fourth quarter 1976.

- Reinjection Wells. Reinjection wells are slant-drilled from a reinjection well island, also to a nominal 6,000-foot depth. A pumped reinjection well with a 10-3/4-inch casing is assumed to flow twice the mass flow of a production well, or approximately 1,600,000 pounds per hour of brine. Drilling time per well is approximately one month. Three brine reinjection wells, one spare and one cooling tower blowdown injection well are required for years 1 through 30 of plant operation. The cooling tower blowdown is not compatible with the reinjection brine, and a separate blowdown injection well is required.
- Production Well Island. One production well island, adjacent to the plant site boundary, is required for the production wells. The well island includes the production wells, sand settling tanks, cold brine dump pit for well startup, cold brine pump for the slow reinjection of cold brine from the pit into the production brine header, an insulated brine header with valves, and associated miscellaneous well equipment.
- Reinjection Well Island. The reinjection well island includes the reinjection wells, a cooling tower blowdown injection line, and an insulated reinjection brine header. One reinjection well island is required for either power plant and is located 2.0 miles from the plant site boundary.
- Field Piping. Insulated production brine piping is above ground due to the short pipe run from the production well island to the plant site fence. This piping for the five active well production island is a 20-inch line. The cooling tower blowdown line and insulated reinjection piping are placed side-by-side and run underground due to the two-mile lengths. The blowdown and reinjection field piping includes the piping from the plant site fence to the reinjection well island. A 20-inch line is required for the reinjection brine flow and an 8-inch line for the cooling tower blowdown flow.

The well field capital cost estimates are based on the plot plans, general arrangement sketches, piping lists, and equipment lists in Sections 8 and 9.

10.2.3 Capital Cost Estimates

The well field capital cost estimate is based on the well field design, which is described in Section 10.2.2.

Pricing. The estimate is at fourth quarter 1976 price and wage levels. No allowance has been made for escalation.

Direct Field Construction Costs. The direct field construction costs of permanent plant equipment, bulk materials, and subcontracts were estimated on the following basis:

- Equipment and Bulk Materials. Suppliers' estimates were obtained for the preinsulated production and reinjection brine piping. Quantity takeoffs for concrete, piping, and excavation were made from the engineering drawings and sketches, and these quantities, together with miscellaneous equipment and materials, were priced using current prices from Bechtel sources.
- Subcontracts. The production and reinjection wells are installed on a subcontract basis; each production and reinjection well costs approximately \$425,000 (Ref. 6-1). The subcontract price includes the cost of drilling, casing, wellhead equipment, directional work, well engineering, and an allowance for equipment failures and unforeseen problems.
- Construction Labor. The average wage rate and the value for labor productivity are the same for the well field capital cost estimate and the plant capital cost estimate; the labor mix for the installation of the well field equipment and piping will be similar to the labor force for power plant construction.

Indirect Field Costs. The well field cost estimate uses a value for the indirect field costs of 65 percent of direct construction labor cost, which is the same as used in the plant capital cost estimates.

Engineering Services. Engineering services have been included at 20 percent of the wellfield surface construction cost. Surface construction costs include the installed cost of the production and reinjection well islands with their associated equipment, excluding the cost of the wells, plus the cost of piping for the production brine, reinjection brine, and cooling tower blowdown. Engineering services for the production and reinjection wells are performed by the subcontractor's drilling engineers and are included with the subcontract drilling cost.

Allowance for Uncertainty. Within the scope of each estimate, an allowance for uncertainty in the quantity of material, pricing of equipment, or productivity of labor has been included. For the production and reinjection wells only, this allowance has been included in the subcontract drilling cost.

Qualifications. The following qualifications apply to each estimate:

- Carbon steel is specified for the production and reinjection geothermal brine piping.
- Production and reinjection wells have a service life of 30 years.

Exclusions. The following items are excluded from the well field capital cost estimates:

- Any special construction, such as widening and strengthening of existing roads
- Client engineering, financing, and other client costs⁽¹⁾
- Environmental data acquisition, preparation, and filing of reports⁽¹⁾
- Land acquisition and rent⁽¹⁾
- Royalties and process licenses⁽²⁾

- Allowance for interest during construction⁽¹⁾
- Training of well field operator; well field startup and operation⁽²⁾

Notes: (1) Included with Owner's Costs in the Cost of Electric Energy, Section 10.3.

(2) Included in the Cost of Electric Energy, Section 10.3.

Estimate Table. The total estimated costs of the well field surface equipment, production and reinjection wells, engineering services, and allowance for uncertainty for the 50 MWe power plants with and without regeneration, are shown in Table 10-4. Also shown are the number of production and reinjection wells and the number of production and reinjection islands required for each plant.

Table 10-4

CONCEPTUAL WELL FIELD CAPITAL COST ESTIMATE
(WITH AND WITHOUT REGENERATION)
50 MWe (NET) GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

Number of Production Wells	5
Number of Reinjection Wells	4
Number of Production Well Islands	1
Number of Reinjection Well Islands	1
Installed Cost (\$1,000) ⁽¹⁾	
Surface Equipment	4,800
Production and Reinjection Wells	3,800
Field Construction Cost	8,600
Engineering Services	1,000
Allowance for Uncertainty	1,200
Total Installed Cost	10,800

Note: (1) Fourth quarter 1976.

10.3 ENERGY PRODUCTION COSTS

Energy production costs for the power plants and well fields in the Niland study are estimated according to the same bases and approach as discussed in Sections 7.1 and 7.2. As in the Heber study, well field energy production costs were estimated with both a low-risk, utility financed discounted cash flow (DCF) rate of return of 10.8 percent and a risk-adjusted, energy company financed DCF rate of return of 20 percent. As mentioned earlier, it is probable that capital for geothermal well field developments will be obtained at a risk-adjusted rate of return that is higher than the low-risk, 10.8 percent rate of return.

Table 10-5 presents a summary of the energy production costs estimated for the multistage flash/binary plants both with and without regeneration. These results are based on an 85 percent plant capacity factor. Capacity factors other than 85 percent will produce an inversely proportional change in energy production costs.

Details of the costs shown in Table 10-5 are presented in Tables 10-6 for the plant without regeneration and the plant with regeneration. An analysis of the results of these energy production cost estimates is presented in Section 11.

Table 10-5.

SUMMARY OF ENERGY PRODUCTION COSTS

	Net Power Output	Power Plant Cost	Well Field Cost	Total Cost
	(MWe)	(Mills/kWh)	(Mills/kWh)	(Mills/kWh)
Multistage Flash/Binary Plant without Regeneration	50.0	24.2	10.2 @10.8% ⁽¹⁾	34.4
	—	—	17.0 @20%	41.2
Multistage Flash/Binary Plant with Regeneration	50.0	24.0	10.2 @10.8%	34.2
	—	—	17.0 @20%	41.0

Note:

- (1) 10.8% is a low-risk, utility financed discounted cash flow rate of return; 20% is a risk-adjusted, energy company financed discounted cash flow rate of return

Table 10-6

DETAILS OF ENERGY PRODUCTION COSTS
(85% capacity factor in All Cases)

Power Plant		
Multistage Flash/Binary Plant	Without Regeneration	With Regeneration
Power Output	50.0 MWe	50.0 MWe
Plant Capital Cost ⁽¹⁾	\$47.3 Million	\$46.9 Million
Depreciation + Return + Income Taxes	17.8 mills/kWh	17.6 mills/kWh
Ad Valorem Taxes	3.2	3.2
Plant Insurance	0.1	0.1
Operation and Maintenance	2.5	2.5
Administration and General	0.6	0.6
Total Power Plant Costs	24.2 mills/kWh	24.0 mills/kWh
Well Field		
Financing Basis	Regulated Utility	Energy Company
Rate of Return	10.8%	20%
Book Depreciation	1.3 mills/kWh	1.1 mills/kWh
Return on Investment	3.1	5.6
Income Taxes	1.2 ⁽²⁾	5.1 ⁽³⁾
Ad Valorem Taxes	0.6	1.0
Operation	0.7	0.7
Maintenance	1.6	1.6
Administration and General	0.2	0.2
Royalties	1.0	1.7
Reservoir Development	0.5	0
Total Well Field Costs	10.2 mills/kWh	17.0 mills/kWh

(1) Includes construction cost, owner's costs, and AFDC

(2) Includes deduction for bonded debt interest

(3) 100% equity financed (no interest deduction)

Section 11

COMPARISONS

This section presents a comparison of the processes with and without regeneration, including the effects of design, performance, and costs and the environmental effects.

11.1 DESIGN

The introduction of a regenerator in the isopentane system changes the pressure and temperature state points of the multistage flash/binary process. This is due to the increased pressure drop on both the vapor and liquid sides of the regenerator and the heat transferred from the isopentane vapor to the isopentane liquid by the regenerator. Table 9-1 compares the flow rates and the thermodynamic state points for the multistage flash/binary process, with and without regeneration, and Table 9-2 compares the auxiliary power requirements. The effects of the changes are discussed below.

The isopentane vapor pressure of 28.8 psia, at the inlet to the condenser (turbine exit), is dependent upon the cooling water inlet temperature. For design conditions, this water temperature is constant, therefore, the condenser inlet pressure is the same for both the process with regeneration and the process without regeneration. Due to the introduction of the regenerator, which has a pressure drop of 4 psi, the turbine exhaust pressure is increased to 32.8 psia. As the regenerator does not change the turbine inlet conditions of 550 psia, 390°F, the work from the vapor expansion through the turbine is reduced due to the increased backpressure. In order to maintain

the same net power output of 50 MWe from the plant, the introduction of the regenerator requires the isopentane flow to be increased by 5 percent to 5.63×10^6 pounds per hour.

On the isopentane liquid side of the regenerator, the pressure drop is 13 psi. This additional system pressure has to be made up by increased discharge pressure from the feed pumps. In the isopentane system, the major effect of the regenerator pressure drops is to increase the electrical power required by the low pressure feed pumps by 11 percent and to increase the power required by the main feed pump turbine by 5 percent.

Since the heat content of the isopentane vapor is reduced as it flows through the regenerator, the condenser duty and, therefore, its heat transfer surface area is reduced. With a reduction in condenser inlet vapor temperature from 212°F to 130°F , the condenser heat transfer surface area is reduced by 9 percent. In addition, since the cooling water temperature rise across the condenser is constant, the rate of cooling water flow in the system is reduced by 16 percent to 36.8×10^6 pounds per hour. The smaller cooling water flow rate reduces the required capacity and power of the circulating water pumps and also reduces the size and power requirements of the cooling tower.

The isopentane liquid, at the outlet from the regenerator, is increased in temperature by 74°F to 191°F , which means that less heat has to be transferred from the brine in the multistage flash units. This reduces the number of stages in each of the four flash vessels from 12 to 10 and reduces the heat transfer tube surface by 16 percent. The duty of the separator-heat exchanger is increased by 5 percent due to the increased isopentane flow.

The preheated isopentane liquid affects the heat balance in the brine system. The higher temperature of the isopentane liquid entering the multistage flash unit increases the temperature of the brine leaving the plant by 76°F to 228°F. Therefore, although the heat transferred in the multistage flash units and the separator-heat exchanger is less, the higher brine exiting temperature reduces the heat extracted from each pound of brine supplied to the plant. The overall result is that the brine system flow rate is increased by 2 percent to 3.67×10^6 pounds per hour. With a higher leaving temperature, the brine has to be expanded through fewer stages in the multistage flash units. The corresponding pressure of the brine as it leaves the multistage flash unit is then 15.6 psia, compared with 3.04 psia for the process without regeneration. As this increases the brine reinjection pump suction pressure, there will be a reduction in the pump differential head. With the change in pump flow and differential head, the pumping power is reduced by 3 percent.

As the pressure in all the stages of the multistage flash vessels is above 15.6 psia, which is above atmospheric pressure, the noncondensable gases are vented without the assistance of the ejector unit that is required for the process without regeneration.

11.2 PERFORMANCE

Performance parameters for the multistage flash/binary process with and without regeneration are compared in Table 11-1.

The total brine system flow rate of 3.67×10^6 pounds per hour for the process with regeneration is 2 percent greater than that for the process without regeneration. Since the net power output for both processes is the same (50 MWe), the process performance in terms of specific net energy, which is equal to net power divided by the brine flow, is less for the process with regeneration by 2 percent.

Table 11-1

COMPARISON OF PLANTS WITH AND WITHOUT REGENERATION
50 MWe GEOTHERMAL POWER PLANT
NILAND, CALIFORNIA

	Units	Without Regeneration	With Regeneration	Percent Change
Brine Inlet Flow Rate	(10 ⁶ lb/hr)	3.60	3.67	+2
Brine Outlet Flow Rate	(10 ⁶ lb/hr)	3.57	3.63	+2
Brine Outlet Temperature	(°F)	154	229	+12 ⁽¹⁾
Vented Gas Flow Rate	(10 ⁶ lb/hr)	0.180	0.183	+2
Gross Power Generated	(kWe)	55,650	55,050	-1
Auxiliary Power (Electrical)	(kWe)	5,650	5,050	-10
Auxiliary Power (Mechanical)	(hp)	6,610	6,920	+5
Net Power Output	(kWe)	50,000	50,000	0
Specific Net Energy	(Wh/lb)	13.9	13.6	-2
Cooling Water Evapora- tion and Drift	(10 ⁶ lb/hr)	1.02	0.33	-18
Cooling Water Blowdown	(10 ⁶ lb/hr)	0.51	0.41	-21
Cooling Water Makeup	(10 ⁶ lb/hr)	1.53	1.24	-19
	(acre-ft/yr)	3,270	2,650	-19
Plant Capital Cost				
	(Million \$)	39.5	39.2	-0.8
	(mills/kWh)	24.2	24.0	-0.8
Well Field Cost				
10.8% ⁽²⁾	(mills/kWh)	10.2	10.2	0
20% ⁽²⁾	(mills/kWh)	17.0	17.0	0
Total Cost of Energy				
10.8% ⁽²⁾	(mills/kWh)	34.4	34.2	-0.6
20%	(mills/kWh)	41.2	41.0	-0.5

Notes:

(1) Based on absolute temperature

(2) Well field costs were computed as follows:

10.8% is a low risk, utility financed discounted cash flow rate of return;
20% is a risk-adjusted, energy company financed discounted cash flow rate
of return.

Normally, lower gross power output is consistent with lower brine flow rates. However, with the regeneration process the auxiliary power requirements are down by 10 percent from 5,650 kW to 5,050 kW. This is due to the reduction in cooling water system power requirements outweighing the increase in isopentane pumping power. Therefore, as the net power output is constant at 50 MWe, the gross power output is less for the regenerative process, even though it requires a greater brine flow rate.

11.3 COSTS

The cost of electric energy produced by the multistage flash/binary process with regeneration is 34.2 to 41.0 mills/kWh (depending on the type of well field financing) and is less than 1 percent lower than that of the process without regeneration. For a given type of well field financing, all of the energy production cost differences are due to the difference in the power plant's capital costs. Well field costs are the same for both processes.

The addition of the two regenerators has the net effect of decreasing the capital cost of the plant with regeneration by approximately \$300,000. The additional cost of the regenerators is more than offset by the savings in smaller pumps, shorter multistage flash units, smaller condensers, and a reduced number of cells in the cooling tower. On the other hand, piping and instrumentation costs are slightly higher for the plant with regeneration.

11.4 ENVIRONMENTAL EFFECTS

The environmental effects for the 50 MWe multistage flash/binary process with and without regeneration are also compared in Table 11-1. The major changes in environmental impact caused by the addition of regeneration are associated with brine reinjection conditions, noncondensable gas processing prior to venting, and cooling water makeup and blowdown requirements.

The brine inlet (production) flow rate is approximately equal to the brine outlet (reinjection) flow rate for both processes. In both cases, the 0.5 percent difference between the system inlet and outlet is due to non-condensable gases that are vented to the atmosphere. The vented gases are mainly carbon dioxide and trace amounts of methane and ammonia. Most of the hydrogen sulfide present in the gases is redissolved in brine exiting the plant by a scrubber and reinjected with the cool brine.

For the process with regeneration, the brine reinjection temperature is increased by 75°F to 229°F. This may contribute to a lower reservoir temperature decay rate over the lifetime of the power plant. However, such a contribution cannot be anticipated with any certainty, since there has been no long-term reinjection experience. One possible benefit of a higher brine reinjection temperature, is increased solubility of silica, barium sulfate, and strontium sulfate. This may result in less scaling in the reinjection line and may extend the life of the reinjection wells. However, it is anticipated that scaling from calcium sulfate may be somewhat greater at higher temperatures, because of its reverse temperature-solubility relationship.

The process with regeneration, because of its lower heat rejection rate, loses less cooling water by evaporation and drift. Therefore, its total blowdown and makeup flow rates are correspondingly less. For the process with regeneration, approximately 1.24×10^6 pounds per hour of makeup water to the cooling water system are required under cooling tower design conditions (79° wet bulb ambient temperature). This is 19 percent less than the process without regeneration with the same wet bulb temperature and gives a significant reduction in annual water usage. The average makeup water requirement throughout the year is about 78 percent of the design makeup water requirement and amounts to approximately 2,650 acre-feet of total annual water consumption, assuming the 85 percent plant capacity factor. This compares with a requirement of 3,270 acre-feet of water for the process without regeneration.

For the process with regeneration, cooling tower blowdown is discharged from the cooling water system at a rate of 0.41×10^6 pounds per hour under design conditions, which is a reduction of 21 percent compared with the process without regeneration. Blowdown is required, since the concentration of dissolved solids in the cooling water is continually increasing due to evaporation in the cooling tower. Blowdown controls the level of concentration to approximately three times the value of dissolved solids in the makeup water. This wastewater, after deaeration, is pumped to the well field and injected into the reservoir by a single, but separate well.

In the process with regeneration, the evaporation and drift is 0.83×10^6 pounds per hour, which is a reduction of 18 percent

To summarize, the environmental effects of adding regeneration to the multistage flash/binary process are all positive. Cooling water makeup and blowdown requirements are substantially reduced as is heat rejection to the atmosphere by evaporation from the cooling tower. Additionally, the brine reinjection temperature is increased by 75°F .

APPENDIX

COMPUTER PROGRAM GEOPRS CALCULATION PROCEDURE

1.0 OBJECTIVE OF COMPUTER PROGRAM GEOPRS

The steam turbine for a geothermal power plant using the flashed-steam energy conversion process is designed to admit steam at specified inlet pressures. For a given initial brine temperature, given initial flash pressures, and the given turbine, program GEOPRS calculates new flash pressures based on different inlet brine temperatures for two plant operating modes:

- (1) Constant plant net output power, which is maintained by controlling the brine flow rate
- (2) Constant brine flow rate

Flash pressures calculated by GEOPRS are input to GEOTHM, which calculates the plant performance.

2.0 ASSUMPTIONS

The following assumptions have been made:

- (1) A two-stage flashed-steam energy conversion process is used.
- (2) Perfect gas relationships hold.
- (3) Impulse-type turbines such as those manufactured by General Electric and Mitsubishi are used.
- (4) The turbine contains five stages with admission of low pressure steam between the second and third stages. The program can be readily extended to perform calculations for any number of stages.

- (5) The mass flow rate of steam to the steam jet ejector is negligible compared to the mass flow rate of steam generated in the first-stage flash vessel.
- (6) The computations are being performed for low-salinity geothermal brine resources whose thermodynamic properties can be closely approximated by those of pure water.

3.0 CALCULATIONS

3.1 CONSTANTS THAT ARE INPUT TO THE PROGRAM:

- Brine Temperature, T_B
- Brine flow rate, $\dot{w}_B$

3.2 INITIAL VALUES THAT ARE INPUT TO THE PROGRAM

After the first iteration of the program, these parameters have the values obtained from the last simultaneous solution of Equations 8 through 14 listed below.

- Turbine stage pressures p_1 through p_5
- High and low pressure steam flow rates, $\dot{w}_H$ and $\dot{w}_L$

3.3 CALCULATION OF TURBINE CONSTANTS C_1 THROUGH C_5

- 3.3.1 Pressures P_1 and P_3 are selected to obtain maximum specific net energy for initial plant operation, assuming that only the last turbine stage is choked.
- 3.3.2 The GEOTHM program calculates the brine flow rate for the appropriate brine temperature and the desired net output.
- 3.3.3 A semilog plot of turbine stage pressures is constructed by drawing a straight line through pressures p_1 and p_3 as shown in Figure A-1.

Figure A-1. Stage Inlet Pressure versus Stage Number

3.3.4 Pressures p_2 , p_4 , and p_5 are read from the plot.

3.3.5 v_1 , the specific volume of the steam at the high pressure turbine inlet, is calculated.

3.3.6 h_{2s} is the enthalpy after an isentropic expansion of the high pressure steam from pressure p_1 to pressure p_2 . h_2 is the actual enthalpy upstream of the turbine's second stage (at pressure p_2) and is calculated from:

$$h_2 = h_1 - (h_1 - h_{2s}) \eta_t, \quad (1)$$

where η_t is the overall expansion efficiency of the turbine.

3.3.7 v_2 is determined at the state point defined by pressure p_2 and enthalpy h_2 .

3.3.8 Specific volumes v_3 , v_4 , and v_5 are calculated by the same procedure used to calculate v_2 . For each case, expansion is taken from the superheated vapor state at pressure p_1 , using the expansion efficiency η_t .

3.3.9 Turbine constants C_1 through C_5 are calculated from:

$$C_1 = \frac{\dot{w}_H \sqrt{\frac{v_1}{p_1}}}{\left(\frac{p_2}{p_1}\right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_2}{p_1}\right)^{\frac{K-1}{K}}}} \quad (2)$$

$$C_2 = \frac{\dot{w}_H \sqrt{\frac{v_2}{p_2}}}{\left(\frac{p_3}{p_2}\right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_3}{p_2}\right)^{\frac{K-1}{K}}}} \quad (3)$$

$$C_3 = \frac{(\dot{w}_H + \dot{w}_L) \sqrt{\frac{v_3}{p_3}}}{\left(\frac{p_4}{p_3}\right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_4}{p_3}\right)^{\frac{K-1}{K}}}} \quad (4)$$

$$C_4 = \frac{(\dot{w}_H + \dot{w}_L) \sqrt{\frac{v_4}{p_4}}}{\frac{1}{K} \sqrt{1 - \left(\frac{p_5}{p_4}\right)^{\frac{K-1}{K}}}} \quad (5)$$

$$C_5 = \frac{(\dot{w}_H + \dot{w}_L) \sqrt{\frac{v_5}{p_5}}}{\left(\frac{2}{K+1}\right)^{\frac{1}{K-1}} \sqrt{\frac{K-1}{K+2}}} \quad (6)$$

3.4 CALCULATION OF STATE POINT PROPERTIES

The 1968 ASME steam tables package of subroutines (Ref. 1) is utilized by GEOPRS. This feature enables the program to compute specific volumes and enthalpies.

3.4.1 Calculation of Specific Volumes

- v_1 , the specific volume of the steam at the high pressure turbine inlet is computed from pressure p_1 and enthalpy h_1 in superheated region.
- h_{2s} is the enthalpy after an isentropic expansion of the high pressure steam from its superheated vapor state at p_1 to pressure p_2 . h_2 is the actual enthalpy at pressure p_2 and is calculated from:

$$h_2 = h_1 - (h_1 - h_{2s}) \eta_t$$

- v_2 is determined at the state point defined by pressure p_2 and enthalpy h_2 .

- Specific volumes v_3 , v_4 , and v_5 are calculated by the same procedure used to calculate v_2 . For each case, expansion is taken from the superheated vapor state at pressure p_1 , using the expansion efficiency η_t .

3.4.2 Calculation of Enthalpies

Given the pressure p_1 at the high pressure turbine inlet point and the pressure loss Δp_1 between the first-stage flash tank and the turbine inlet point, enthalpies h_{fH} and h_{gH} are calculated at the saturated states corresponding to the flash pressure $p_1 + \Delta p_1$. Enthalpies h_{fL} and h_{gL} are determined similarly for $p_3 + \Delta p_3$, where p_3 is the pressure at the low pressure admission point and Δp_3 is the pressure loss between the second-stage flash tank and the low pressure admission point.

3.5 GOVERNING EQUATIONS

The following seven equations are solved simultaneously for unknowns p_1 , p_2 , p_3 , p_4 , p_5 , $\dot{w}_H$, and $\dot{w}_L$. Equations 8 through 12 are derived from basic relationships of compressible fluid flow (Ref. 2). Equations 13 and 14 are derived from mass and energy balances around the flash tanks.

$$\dot{w}_H = C_1 \sqrt{\frac{p_1}{v_1}} \left(\frac{p_2}{p_1}\right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_2}{p_1}\right)^{\frac{K-1}{K}}} \quad (8)$$

$$\dot{w}_H = C_2 \sqrt{\frac{p_2}{v_2}} \left(\frac{p_3}{p_2}\right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_3}{p_2}\right)^{\frac{K-1}{K}}} \quad (9)$$

$$\dot{w}_H + \dot{w}_L = C_3 \sqrt{\frac{p_3}{v_3}} \left(\frac{p_4}{p_3} \right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_4}{p_3} \right)^{\frac{K-1}{K}}} \quad (10)$$

$$\dot{w}_H + \dot{w}_L = C_4 \sqrt{\frac{p_4}{v_4}} \left(\frac{p_5}{p_4} \right)^{\frac{1}{K}} \sqrt{1 - \left(\frac{p_5}{p_4} \right)^{\frac{K-1}{K}}} \quad (11)$$

$$\dot{w}_H + \dot{w}_L = C_5 \sqrt{\frac{p_5}{v_5}} \left(\frac{2}{K+1} \right)^{\frac{1}{K-1}} \sqrt{\frac{K-1}{K+1}} \quad (12)$$

$$\dot{w}_H = \dot{w}_B \left(\frac{h_B - h_{fH}}{h_{gH} - h_{fH}} \right) \quad (13)$$

$$\dot{w}_L = \dot{w}_B \left(\frac{h_{fH} - h_{fL}}{h_{gL} - h_{fL}} \right) \left(1 - \frac{h_B - h_{fH}}{h_{gH} - h_{fH}} \right) \quad (14)$$

4.0 METHOD OF SOLUTION

Equations 8 through 14 are solved iteratively as explained below.

- (1) Calculate C_1 through C_5 for a given set of T_B , $\dot{w}_B$, p_1 , and p_2 , representing the plant design conditions.
- (2) Determine values for T_B and $\dot{w}_B$, corresponding to an off-design condition.
- (3) Assume p_1 .
- (4) Calculate $\dot{w}_H$ from Equation 13.
- (5) Calculate p_2 from Equation 8.

- (6) Calculate p_3 from Equation 9.
- (7) Calculate $\dot{w}_L$ from Equation 14.
- (8) Calculate p_4 from Equation 10.
- (9) Calculate p_5 from Equation 11.
- (10) If either of the steam flow rates, $\dot{w}_H$ or $\dot{w}_L$, is larger than or equal to the critical flow rate in calculation steps 5 through 9 (that is, if any of stages 1 through 4 is choked, then go to Step 12.
- (11) If Equation 12 is satisfied within the given limits, then terminate the iterations. The last set of p_1 and p_2 is the solution. Otherwise, go to Step 12.
- (12) Assume a value of p_1 lower than assumed in Step 3 by some specified increment. If this value of p_1 is equal to the previous value within the specified limits, then terminate the iterations. The last set of p_1 and p_2 is the solution. Otherwise go back to Step 4.

- Notes:
- (1) The calculation is completed either when Equation 12 is satisfied or when p_1 converges.
 - (2) Equation 12 may never be satisfied if choking occurs in some stages. For example, if a turbine is designed for the initial year when the brine temperature has its highest value, then some of the first turbine stages may be choked for lower brine temperatures in later years. In such a case, the iteration process converges when the last value of p_1 comes very close to satisfying Equation 12, but is not in fact the exact solution.

NOMENCLATURE

<u>Symbol</u>	<u>Description</u>
$\dot{w}_H$	High pressure steam flow rate (lb/hr)
$\dot{w}_L$	Low pressure steam flow rate (lb/hr)
$\dot{w}_B$	Brine flow rate (lb/hr)
P_1	Pressure ahead of first turbine stage (psia)
P_2	Pressure ahead of second turbine stage (psia)
P_3	Pressure ahead of third turbine stage (psia)
P_4	Pressure ahead of fourth turbine stage (psia)
P_5	Pressure ahead of fifth turbine stage (psia)
T_B	Downhole temperature of brine ($^{\circ}\text{F}$)
C_1	First turbine stage flow rate proportionality constant
C_2	Second turbine stage flow rate proportionality constant
C_3	Third turbine stage flow rate proportionality constant
C_4	Fourth turbine stage flow rate proportionality constant
C_5	Fifth turbine stage flow rate proportionality constant
η_t	Overall turbine expansion efficiency
v_1	Specific volume ahead of first turbine stage (ft^3/lb)
v_2	Specific volume ahead of second turbine stage (ft^3/lb)
v_3	Specific volume ahead of third turbine stage (ft^3/lb)

<u>Symbol</u>	<u>Description</u>
v_4	Specific volume ahead of fourth turbine stage (ft^3/lb)
v_5	Specific volume ahead of fifth turbine stage (ft^3/lb)
h_1	Actual enthalpy of steam upstream of the turbine's first stage (Btu/lb).
h_2	Actual enthalpy of steam upstream of the turbine's second stage (Btu/lb)
h_{2s}	Enthalpy of steam upstream of the turbine's second stage assuming an isentropic expansion across the first stage (Btu/lb)
h_{fH}	Saturated liquid enthalpy at the high flash pressure (Btu/lb)
h_{gH}	Saturated vapor enthalpy at the high flash pressure (Btu/lb)
h_{fL}	Saturated liquid enthalpy at the low flash pressure (Btu/lb)
h_{gL}	Saturated vapor enthalpy at the low flash pressure (Btu/lb)
h_B	Enthalpy of inlet brine (Btu/lb)
K	Ratio of specific heat c_p/c_v
ΔP_1	Difference between the first-stage flash pressure and P_1
ΔP_3	Difference between the second-stage flash pressure and P_3 .

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