MASTER

ENGINEERING AND ECONOMIC FEASIBILITY OF
UTILIZING GEOTHERMAL HEAT FROM THE HEBER
RESERVOIR FOR INDUSTRIAL PROCESSING PURPOSES
AT VALLEY NITROGEN PRODUCERS INC., EL CENTRO
AGRICULTURAL CHEMICAL PLANT

Final Report

By
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K. L. Newman

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ABSTRACT

The engineering and economic feasibility of utilizing geothermal heat from the Heber KGRA for industrial processing purposes at the Valley Nitrogen Producers, Inc. El Centro, California agricultural chemical plant was investigated. The analysis proceeds through the preliminary economics to determine the restraints imposed by geothermal modification size on internal rates of return, and through the energy utilization evaluation to determine the best method for substituting geothermal energy for existing fossil fuel energy. Finally, several geothermal utilization schemes were analyzed for detailed cost-benefit evaluation. An economically viable plan for implementing geothermal energy in the VNP Plant was identified and the final conclusions and recommendations were made based on these detailed cost-benefit analyses. Costs associated with geothermal energy production and implementation were formulated utilizing a modified Battelle Pacific Northwest Laboratories' "GEOCOST" program.

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2. The second part of the document outlines the specific procedures for recording transactions. It details the steps involved in entering data into the system, from initial verification to final posting.

3. The third part of the document addresses the issue of data security. It discusses the various measures that should be implemented to protect sensitive information from unauthorized access or loss.

4. The fourth part of the document focuses on the training of personnel. It highlights the need for ongoing education and skill development to ensure that all staff are competent in their roles.

5. The fifth part of the document discusses the importance of regular audits. It explains how these audits can help identify potential errors or fraud and ensure that the system is operating as intended.

6. The sixth part of the document provides a summary of the key points discussed and offers some final thoughts on the overall goals of the project.

7. The seventh part of the document contains a list of references and sources used in the research.

8. The eighth part of the document is a conclusion that summarizes the findings of the study and provides recommendations for future work.

9. The ninth part of the document is an appendix that contains additional information, such as sample forms and data tables.

10. The tenth part of the document is a glossary of terms used throughout the document.

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SECTION 1

INTRODUCTION

1.1 STATEMENT OF OBJECTIVES

The overall objective of this study was to determine the engineering and economic feasibility of utilizing geothermal heat from the Heber reservoir for industrial processing purposes at the Valley Nitrogen Producers, Inc. (VNP) El Centro, California agricultural chemical plant. A secondary objective was the development of engineering techniques to use geothermal heat in the production of fertilizers and agricultural chemicals in anticipation that these techniques could be translated to other geothermal resource areas where existing or new chemical plants might be located.

The specific objectives of the study were as follows:

- (1) Conduct an in-depth engineering evaluation of the VNP El Centro plant to identify those process systems and components which could utilize geothermal heat as a substitute for fossil fuel or electrically produced heat.
- (2) Conduct heat balance studies of the entire plant to establish the feasibility of substituting geothermal heat for those lower temperature industrial process functions identified as compatible with the geothermal resource.
- (3) Determine heat conversion methods for translating geothermal heat to industrial process heat for those plant functions identified as compatible with the geothermal resource.
- (4) Prepare cost estimates in terms of plant modification (capitalization) and operating costs for each alternative heat conversion approach considered to be feasible.
- (5) Determine the specific benefits of geothermal heat utilization in terms of reduced fossil fuel and electricity consumption and associated reduced energy costs.
- (6) Determine feasible approaches for transporting geothermal heat to the VNP plant based on selected heat delivery approaches.

- (7) Conduct a cost benefit analysis for the entire plant if supplied with geothermal heat based on reduced fossil fuel and electricity costs, cost of geothermal heat, plant modification costs and plant operating costs.
- (8) If it is determined economically feasible to convert the plant to geothermal heat, provide a specific plan of pilot experiments and/or detail engineering requirements to accomplish this objective.

1.2 SUMMARY

This report provides the engineering and economic evaluations of geothermal energy alternatives to natural gas consumption identified for the Valley Nitrogen Producers, Inc. El Centro, California agricultural chemical plant. Initially, an engineering survey of the VNP El Centro plant was conducted to identify and evaluate those process systems and components which could utilize geothermal heat as a substitute for fossil fuel or electrically produced heat. Then, using estimates of well costs, well flow, well life, brine temperature, brine enthalpy, and rates of return on invested capital, the cost of brine production was estimated in terms of a demand charge and an energy charge. Capital costs of geothermal flash steam and binary systems from 5 to 30 Gross MW capacities were estimated utilizing a modified Battelle Pacific Northwest Laboratories "GEOCOST" computer program. Fossil fuel costs, geothermal brine costs, and costs of electrical energy were projected through 1997. Using these data, the thermal cycle efficiencies, and the capital cost data, the projected annual cost savings and the internal rate of return, as a function of the amount of fossil fuel displaced by geothermal energy, were calculated to determine the economic restraints of plant size for potential geothermal modifications. Preliminary conclusions were drawn based on this overall economic evaluation.

In addition to an overall economic evaluation, an individual energy utilization evaluation was undertaken. Using estimates of capital costs, energy costs, and energy conversion efficiencies, a total unit charge rate in \$/Hp-hr was assigned to each existing equipment driver and each proposed energy alternative to determine the best method for substituting geothermal energy for existing fossil fuel energy in the VNP Plant Steam Cycle. A cost-effective plan for individual energy utilization in the VNP Plant Steam Cycle was developed from this evaluation and preliminary conclusions drawn.

For comparison, several geothermal utilization schemes were identified, based on the individual energy utilization analysis, for detailed cost-benefit evaluation. Each proposed

scheme was evaluated based on detailed plant thermal cycle heat balances and detailed capital cost estimates of plant modifications. Final conclusions and recommendations were drawn based on these detailed benefit-cost evaluations.

1.3 CONCLUSIONS AND RECOMMENDATIONS

The conclusions resulting from this engineering and economic feasibility study of utilizing geothermal heat from the Heber reservoir for industrial processing purposes at the Valley Nitrogen Producers, Inc. (VNP) El Centro, California agricultural chemical plant are summarized below.

- An industrial geothermal heat application to the VNP Plant is technically and economically feasible for the hydrothermal resources from the Heber reservoir and can be designed, constructed and operated using current state-of-the-art technology.
- A geothermal binary power cycle utilizing isobutane as the working fluid is economically favored over the flash steam power cycle for replacing existing plant equipment drivers.
- Geothermal brine can be flashed economically to provide process heating functions presently provided by fossil fuel generated steam.
- With a geothermal binary power cycle and flashed auxiliary steam, the VNP Plant can economically eliminate all fossil fuel presently used for steam production without the requirement of additional offsite electrical power demand. However, with the present electrical rate structure, the VNP Plant cannot economically eliminate the present 8 MW demand for offsite electrical power with geothermal energy.
- The elimination of all fossil fuel presently used for steam production without the requirement of additional offsite electrical power demand will require a geothermal binary cycle plant of a gross power equivalent of 34 MW with approximately 9 MW required to run the geothermal auxiliary equipment. The total single-phase brine flow requirement will be approximately 3.1×10^6 lb/hr including brine for flashed auxiliary steam.
- The total estimated capital cost for modifying the VNP Plant is \$26.7 million expressed in fourth-quarter 1977 dollars and includes some allowance

for uncertainty. The estimated internal rate of return to VNP for this capital investment is 14.5 percent based on the present value of money.

- Single-phase brine can be economically piped from the Heber reservoir to the VNP Plant assuming that existing rights-of-way are utilized.

As a result of the VNP Plant engineering and economic feasibility analysis, it is recommended that the following analytical and fieldwork be initiated:

- Provide, as a proof-of-concept geothermal field experiment, a geothermal binary power cycle to replace one of the existing Cooling Water Pump Turbines. Estimated capital costs for such an experiment would be \$2 million. This field experiment would provide VNP with valuable operating experience utilizing hydrothermal resources for non-electric power generation.
- Introducing a toxic and flammable hydrocarbon such as isobutane into the VNP Plant would be difficult to justify from a safety standpoint, therefore additional work should be done to analyze other candidate binary fluids.
- An economic optimization program is recommended for geothermal transport between the Heber reservoir and the VNP Plant. The objective would be to determine whether a cost-benefit would result from transporting cooler brine that is closer to the plant over transporting hotter brine that is at the center of the reservoir.
- Explore the economic advantages of sharing brine transmission costs with other brine users along the rights-of-way between Heber and El Centro.
- Investigate the possibility of a Heber reservoir non-electric geothermal loop which would deliver fluid in a cascade arrangement designed to fully utilize the energy available.

- Look at the economic advantages of increasing plant production capacity by adding additional ammonia refrigeration capacity using a binary driven compression refrigeration unit or a geothermally heated ammonia absorption refrigeration cycle.
- Investigate the possibility of utilizing low level sources of waste heat in the plant, that are presently rejected to the cooling tower, in a binary power cycle.
- As a part of the proof-of-concept geothermal field experiment, begin brine flow tests to the VNP Plant to test brine transmission characteristics such as well reliability, downhole pump reliability, brine scaling characteristics, brine transmission heat losses, and brine reinjection well characteristics.
- Begin investigating institutional barriers and, if required, preparing an environmental impact report for the proposed plant modifications.
- Begin examining potential rights-of-way for a brine transmission pipeline between Heber and VNP. It is recommended that VNP finance the construction of the brine pipeline regardless of who builds it or operates it, so that the investment can be depreciated over a longer period than might be expected if the transmission cost were included with the brine cost.
- Investigate the possibility of reinjecting plant waste water, including cooling tower blowdown, to maintain brine inventory by testing waste water characteristics in well core samples.

1.4 BACKGROUND

The Valley Nitrogen Producers El Centro Plant is part of a grower-owned system of major fertilizer production and distribution facilities organized to provide fertilizer products at low cost to agricultural producers. With growers constantly facing increased costs of farming operations, most of which are energy related, low cost fertilizers become essential to economically viable food production in the United States.

The El Centro plant, operating at full production since 1969, is an energy intensive operation consuming over 25 million SCF of natural gas per day for ammonia feedstock, reformer fuel, and steam generation to power equipment drivers. Its location in the Heber Known Geothermal Resource Area (KGRA) makes it an appropriate candidate for detailed engineering and economic evaluation of possible applications of geothermal heat to plant energy needs.

Valley Nitrogen Producers was notified by Southern California Gas Company in March 1976 that the supply of natural gas to the plant for steam generation would be subject to curtailment based on a California Public Utilities Commission (CPUC) system of end-use priorities established in December 1975. Natural gas would continue to be supplied as NH_3 feedstock and reformer fuel under a 2-A priority. Based on this system the VNP El Centro plant could experience curtailment of natural gas for use as boiler fuel for up to 250 days per year. Under the CPUC order conversion of the plants steam producing boilers was to be completed by December 1976. The company appealed for and received an additional year delay (until December 1977) in assigning a Priority 4 (curtailment of delivery up to 250 days/year) to its industrial boilers in order to complete plant modifications necessary to burn fuel oil (install fuel oil tanks, modify boilers, air pollution control devices, etc.). Nevertheless a conversion of the boilers to fuel oil combustion is underway as a result of the decision and with it associated increases in energy costs will be incurred. The company considers it imperative to evaluate alternative energy sources in conjunction with the conversion of the plant boilers to burn fuel oil and especially imperative to evaluate the use of geothermal heat as a partial energy source considering the fact that the plant is situated on a KGRA.

1.5 DESCRIPTION OF THE HEBER KGRA

1.5.1 Introduction

The geothermal reservoir which is the energy source for this study is embodied in a 13.5 square mile area known as the Heber Known Geothermal Resource Area (KGRA) in the Imperial Valley. This is the southernmost anomaly identified in the Imperial Valley. The area of maximum temperature gradient is centered around the township of Heber which is approximately 2-1/2 miles south of the VNP Plant. The VNP Plant is within the boundary of the Heber KGRA, as designated

by the U.S. Geological Survey. Figure 1-1 indicates the location of the VNP plant with relation to the township of Heber and the 50 MW geothermal plant site proposed by EPRI.

The land within the Heber KGRA is under private ownership and is principally devoted to intensive agricultural utilization. Other land uses include urban and industrial developments. Portions of the City of El Centro, along with the VNP plant, are included in the northern area of the KGRA and the entire Township of Heber is included in the central area.

Geothermal development in the Heber KGRA has been due primarily to the efforts of the Chevron Oil Company, Magma Power and associated organizations. This area has been considered a potential heat anomaly since 1945 when an oil and gas test well was drilled just west of the Heber townsite. Well logs indicated a higher-than-normal heat gradient. In 1963, Chevron confirmed the Heber geothermal anomaly by drilling a shallow test hole and measuring the heat gradient. In 1971, Chevron initiated a geophysical program to more fully evaluate the geothermal potential of the area.

Early in 1972, Magma Energy, Inc., in conjunction with Chevron Oil Company, drilled the Holtz Well #1 to a depth of 5,148 ft. in an area approximately 1 mile southwest of Heber Township. Well conditions were encouraging and prompted Magma to drill a second well nearby. In the fall of 1972, Chevron drilled its first well, Nowlin #1 to a depth of 5,030 ft. in an area due east of the Magma wells.

In 1973, Chevron, New Albion Resources Company (a subsidiary of San Diego Gas & Electric Company) and Magma agreed to a joint-venture at Heber to test and evaluate the geothermal potential indicated in the earlier wells. Chevron was designated as operator for the joint-venture. The test project began in late 1973 and was completed in mid-December 1974. The objective of this program was to determine production and injection capability of the Heber reservoir. Chevron's Nowlin #1 and Magma's Holtz #1 wells were produced and reservoir fluids were injected into Magma's Holtz well #2. Results of these tests encouraged the drilling of three additional wells, two by the Chevron-New Albion-Magma joint venture and one by Chevron on its own behalf.

In 1975, a major effort was funded by the Electric Power Research Institute (EPRI) which, *inter alia*, was to determine the feasibility of constructing and operating a 50 MWe, binary cycle, electric generating demonstration plant

● EXISTING GEOTHERMAL WELLS
 HEBER QUADRANGLE MAP
 7.5 MINUTE SERIES (TOPOGRAPHICAL)
 U. S. DEPT. OF THE INTERIOR
 GEOLOGICAL SURVEY 1957

FIGURE 1-1
 VNP PLANT LOCATION

utilizing the hydro-thermal resources of the Heber KGRA. The results of this study and subsequent plans by EPRI and San Diego Gas & Electric Company to construct a plant at Heber directly impact on resource utilization by the Valley Nitrogen Producers El Centro plant. For this reason, we have established technical communications channels with EPRI, Chevron Oil Company as the major geothermal lease holder, and San Diego Gas & Electric Company.

1.5.2 Reservoir Operation

The geothermal lease holders at the Heber reservoir require that they maintain control of all production and reinjection. Brine within given parameters will be delivered to the VNP plant and waste brine accepted at that point.

Although details of the Heber KGRA are considered proprietary, adequate information has been published to establish basic reservoir characteristics for the purposes of this study. Table 1-1 shows brine chemistry for five wells in an area of three square miles in the center of the KGRA. The Valley Nitrogen Producers El Centro plant is four miles north of the proposed Heber 50 MW power plant, 2.7 miles north of "HULSE No. 1" and on the outer edge of an area where well temperature gradients should be 4° to 6°F per 100 feet in depth. Down hole brine temperatures at the center of the reservoir are in the vicinity of 350-400°F giving a range of options concerning brine temperatures and pressures that can be delivered to the plant.

The reservoir characteristics established in paragraph 1.5.3 are based on the chemistry data in Table 1-1, discussions with the reservoir leaseholder and the assumption that properties of the brine will remain constant over the useful economic life of the VNP plant.

1.5.3 Reservoir Characteristics

Engineering calculations and preliminary system design schemes will be developed based on the following criteria which the leaseholders at Heber have indicated they can meet:

Total Dissolved Solids (TDS)	14000 ppm
Brine Chemistry for Thermodynamic Calculations	14000 ppm solution of NaCl
pH	6.2

Table 1-1

CHEMICAL QUALITY OF WATER, HEBER GEOTHERMAL RESERVOIR
IMPERIAL VALLEY, CALIFORNIA

Parameter*	Nowlin#1	Holtz#1	Holtz#2	C.B. Jackson#1	J.D. Jackson#1
Total Dissolved Solids (TDS)	14,100	13,168	16,330	15,430	15,275
SiO ₂	120	268	187	267	268
Li	6.6	4	4.1	2.8	3.4
Na	3,600	5,500	4,720	4,688	4,563
K	360	220	231	181	197
Ca	880	1,062	1,062	891	781
Mg	2.4	5.6	23	4.7	3.8
Cl	9,000	7,420	8,242	8,320	8,076
SO ₄	100	100	148	152	150
CO ₃	4	NA	NA	NA	NA
HCO ₃	20	NA	NA	NA	NA
F	1.6	1.7	1.5	0.9	0.6
B	4.8	4.1	8	4.8	5.2
Fe	0.9	15	5	20	10
Mn	NA	0.9	0.9	1.3	1.9
Pb	0.1	1.6	0.6	0.6	0.9
Zn	0.68	0.3	0.1	0.4	0.5
Cu	0.2	0.5	0.4	0.4	0.4
Ba	NA	6	3	3	3
Sr	NA	37	42	32	36
Al	0.04	15	12	0.5	18
Ag	NA	NA	NA	NA	NA
Li	4	NA	NA	NA	NA
pH	7.1	NA	7.4	5.8	6.5

*Except pH, all parameters are in parts per million.

CO ₂ by weight of flashed steam	$\leq 0.3\%$
Methane and hydrogen sulfide by weight of flashed steam	trace
Maximum supply rate to VNP plant	500,000 lb/hr per well
Downhole Brine Condition	Saturated @ 360°F
Brine return temperature at reinjection well	$\geq 160^{\circ}\text{F}$

1.6 PLANT DESCRIPTION

1.6.1 General Background Information

The Valley Nitrogen Producers (VNP) El Centro fertilizer and agricultural chemical plant produces four primary nitrogen products:

- (1) Ammonia
- (2) Urea
- (3) Nitric Acid
- (4) Ammonium Nitrate

It also produces fertilizer products such as Tri N 32 (liquid fertilizer) and aqua ammonia by additional processing of the primary products. The plant facility is dedicated to the production of fertilizers and agricultural chemicals. In approximate terms the plant can produce the following quantities of chemicals:

(1) Ammonia (NH ₃)	600 tons/day
(2) Urea	450 tons/day
(3) Nitric Acid	100 tons/day
(4) Ammonium Nitrate	125 tons/day

The nitric acid production is consumed in the production of ammonium nitrate. Because of the increasing demand for liquid fertilizers a substantial portion of the ammonium nitrate production is consumed in the manufacture of Tri N 32 a non-volatile liquid fertilizer with low corrosive properties.

The plant normally operates 24 hours a day, seven days a week except for maintenance actions. Figure 1-2 shows a block diagram of the Valley Nitrogen Plant flow streams.

VALLEY NITROGEN PRODUCERS, INC.

FERTILIZER PRODUCTION BLOCK DIAGRAM

EL CENTRO PLANT

FIGURE 1-2

1.6.2 Production Methods

The production of ammonia is accomplished by using three raw materials - natural gas, water (as steam), and air. These materials react under conditions of elevated temperature and pressure in the presence of catalyst and with suitable purification steps such that a mixture of nitrogen and hydrogen is obtained. As a part of this process, a by-product stream of carbon dioxide is formed, which is either vented to the atmosphere or alternately is used as a raw material for urea production. The mixture of nitrogen and hydrogen, known as Synthesis gas, is produced in a precise ratio necessary for conversion to anhydrous ammonia, which is a chemically combined formula of these two gases. The conversion of the Synthesis gas to anhydrous ammonia is accomplished under conditions of elevated pressure and temperature in the presence of a suitable catalyst. The resulting product is a gas under normal conditions. For economic reasons, it is condensed for storage as a liquid. About one-half the ammonia is shipped directly as a product, the balance is used in production of other chemicals - mostly urea. The plant is designed to produce 600 tons/day of ammonia.

The urea plant is designed to produce about 450 tons per stream day of urea. The urea product, in the form of prills, is used as bulk fertilizer and a bulk feed supplement. It is shipped by bulk or bag from the plant by rail or truck. Urea is produced using as raw materials ammonia and carbon dioxide. Both of these raw materials are available from the ammonia plant. The reaction is accomplished at high pressure and moderate temperatures, forming a urea-water solution which is evaporated to a molten urea product. The product is then cooled and formed into prills by the use of the prill tower. The prills are conveyed to storage where bulk urea is made ready for shipping.

Quantities of ammonia are also consumed in the production of nitric acid and ammonium nitrate. Both ammonium nitrate and urea are consumed in the production of Tri N 32 which is currently a fertilizer product in high demand from the plant (over 6,000 tons per month are presently shipped).

1.6.3 Energy/Raw Materials Utilization

The fertilizer (and bulk feed) production process utilizes only three basic raw materials: air, water and natural gas. The plant uses about 3 million gallons of

water per day supplied by the Imperial Irrigation District (IID) and consumes about 25-27 million standard cubic feet (scf) of natural gas per day supplied by the Southern California Gas Company. About 60 percent of the natural gas is used as ammonia feedstock and fuel for the primary gas reform. About 40 percent of the natural gas is used as fuel gas for steam production.

Additionally, the facility consumes about 180,000 kilowatt hours (KWH) of electricity per day. For this particular plant there is no presently economic substitute for natural gas as a raw material feedstock and primary gas reform fuel for the ammonia production process. However, it is the use of natural gas for steam generation and the consumption of electricity for other plant industrial purposes (heaters, motors, etc.) to which this study for using geothermal heat is directed.

Present energy consumption results in a natural gas cost approaching \$1,000,000 per month and an electrical consumption cost of approximately \$100,000 per month. These factors will continue to escalate with the anticipated rise in both fossil fuel and electricity costs. For steam generation approximately 10 million scf of natural gas are consumed per day for production of 1,500 psi and 450 psi steam which is used in a variety of plant functions which are discussed in detail in the following sections.

1.6.4 Plant Engineering Survey

1.6.4.1 Background

A detailed engineering survey of the existing plant facility was conducted to identify process functions which lend themselves to the utilization of geothermal heat rather than fossil fuel or electrically generated heat. The survey concentrated on developing a model of the plant steam cycle since the primary opportunity to substitute geothermal for fossil fuel energy at the VNP plant will be in the reduction of fired steam production.

1.6.4.2 Steam Generation

The plant steam cycle begins with canal make-up water, supplied by the Imperial Irrigation District, going to the pretreatment water clarifier (See Figure 1-3). The clarified water provides cooling tower make-up water and feedwater to the Demineralization Water Treatment Plant. The mixed bed effluent from the Demineralization Water

FIGURE 1-3

Treatment Plant provides demineralized make-up water, at ambient temperature, to the Package Boiler Deaerators. The mixed bed effluent also provides make-up water to the Ammonia Plant Deaerator, by way of the Ammonia Plant Boiler Feedwater and Condensate Heater. The Ammonia Plant Deaerator provides boiler feedwater to the 1,500 psi gas fired P.C.C. Superheater-Boiler and Process Gas Waste Heat Boilers, which provide almost all the steam requirements of the Ammonia Plant (See Figure 1-4).

The Package Boiler Deaerators provide boiler feedwater to the Nitric Acid Plant and the 450 psi fossil fired Package Boilers (See Figure 1-5). Almost all Nitric Acid Plant steam requirements are provided by a 250 psi process gas combustion unit and a waste gas combustion unit within the Nitric Acid Plant. The Nitric Acid Plant requires no substantial fossil fired steam generation, however the waste gas combustion unit does require a small amount of natural gas to complete combustion and meet EPA Emissions Standards. Modifications to the Nitric Acid Plant will only be considered if a supplemental source of steam is required for other plant areas.

The 450 psi Package Boilers provide Ammonia and Nitric Acid Plant start-up steam and all the steam requirements for the Urea Plant as well as the common plant areas, as described in the following sections.

1.6.4.3 Steam Usage

1.6.4.3.1 Ammonia Plant

The 1500 psi steam, generated in the Ammonia Plant P.C.C. Unit, is used exclusively to drive the Synthesis Gas Compressor Turbine (See Figure 1-6). The greater part of the turbine steam is extracted at 450 psi to supply the Ammonia Plant steam requirements, while the remainder of the turbine steam is exhausted to full condensing. An additional 46,100 lb/hr for Ammonia Plant 450 psi steam requirements is supplied by the fossil fuel fired Package Boilers of the Common 450 psi Steam System. The Ammonia Plant 450 psi steam system provides 97,700 lb/hr for process steam, which is mostly consumed in chemical reactions. Part of the remaining gassy condensate is used in the Urea Plant with the remainder going to waste. The 450 psi steam system also provides 204,400 lb/hr for turbine drives, which exhaust to three discreet states, providing steam for the low pressure steam requirements. Eight turbines exhaust at 50 psi, providing

AMMONIA PLANT BOILER FEEDWATER & CONDENSATE

FIGURE 1-5

FIGURE 1-6

steam for Ammonia Plant and Package Boiler Deaerator heating and for the major driving force of the Refrigeration Compressor Turbine. An excess of 11,160 lb/hr of 50 psi steam exists in the Ammonia Plant, which goes to the Ammonia Storage and Solution Formulation Areas. The Refrigeration Compressor Turbine is driven by both 450 psi and 50 psi steam, which both go to full condensing. The Process Air Compressor Turbine Drive is supplied from 450 psi steam with 3000 lb/hr extracted for a 150 psi steam supply, and the remaining steam going to full condensing. The 150 psi steam provides condenser steam jet air ejectors and heating for the MEA Purifier. Five additional small turbines take 450 psi steam and expand it to full condensing without any additional extraction.

The condensate from the Ammonia Plant Condensers and the MEA Purifier return, in order, to the Condensate Polisher, Boiler Feedwater and Condensate Heater, and Ammonia Plant Deaerator, thereby completing the Ammonia Plant Steam Cycle. The losses from the Ammonia Plant Steam Cycle total 93,770 lb/hr, which is equal to the make-up rate from the Demineralization Water Treatment Plant.

1.6.4.3.2 Urea Plant

The 450 psi Package Boilers provide steam to the Urea Plant to drive the Hydraulic Supply Pump Turbine and the Auxiliary Carbamate Pump Turbine (See Figure 1-7). The Auxiliary Carbamate Pump Turbine exhausts to the 50 psi steam header and is considered a "spare" for the purposes of this study. The Hydraulic Supply Pump Turbine exhausts to a desuperheater, which mixes turbine exhaust, 450 psi steam, and Package Boiler Feedwater to provide a 150 psi saturated steam supply to the 150 psi users. A small part of the 150 psi steam is throttled to 50 psi, with the remaining steam users being supplied at this level. The 150 psi condensate is flashed in a Condensate Flash Tank to generate more 50 psi steam. The Condensate Flash Tank bottoms combine with the 50 psi condensate to make up the Urea Plant Condensate Return. Condensate users in the Urea Plant are supplied by the Ammonia Plant gassy condensate. The Urea Plant condensate is returned to the Package Boiler Deaerators to complete the Urea Plant steam cycle. The losses from the Urea Plant steam system total 1500 lb/hr.

1.6.4.3.3 Common Plant Areas

The 450 psi Package Boilers provide steam to the Ammonia Plant, Urea Plant and common plant areas (See Figure 1-8). A nominal amount of steam is also provided to the Nitric Acid Plant. The 450 psi steam is used directly to drive the Cooling Tower Pump Turbines, and Demineralized

COMMON 450 psi STEAM SYSTEM

FIGURE 1-7

The diagram illustrates a steam system with the following components and flow details:

- 450 psi STEAM** (465 P, 595 F, 1298.6 h) enters from the top left.
- LOSSES**: 500 LB/h.
- HYDRAULIC SUPPLY PUMP TURBINE**: Receives 40,650 LB/h of steam, discharging at 465 F and 1251.6 h.
- AUXILIARY CARBAMATE PUMP TURBINE**: Receives 0 LB/h of steam, discharging at 0 LB/h.
- CONDENSATE USERS**: Receives 3970 LB/h of condensate.
- DESUPERHEATER**: Receives 6740 LB/h of steam, discharging at 477 F and 1258.3 h.
- 175 P**: Pressure point after the desuperheater.
- 150 psi STEAM** (165 P, 366 F, 1195.6 h) enters from the middle left.
- 150 psi USERS**: Two users receiving 32,100 LB/h and 15,560 LB/h of steam.
- LOSSES**: 500 LB/h.
- PACKAGE BOILER DEAERATORS (2)**: Receives 2910 LB/h of steam, discharging at 51,070 LB/h.
- AMMONIA PLANT GASSY CONDENSATE**: Receives 3970 LB/h of condensate.
- 50 psi STEAM** (65 P, 305 F, 1184.4 h) enters from the bottom left.
- 50 psi USERS**: One user receiving 4700 LB/h of steam.
- LOSSES**: 500 LB/h.
- CONDENSATE FLASH TANK** (65 P): Receives 32,100 LB/h of condensate, discharging at 2290 LB/h and 1179.1 h.
- UREA PLANT CONDENSATE RETURN**: Receives 50,070 LB/h of condensate.
- 0 LB NORMAL**: Indicated at several points in the system.

Legend:

- WATER
- STEAM
- LB — FLOW, POUNDS PER HOUR
- GPM — FLOW, GALLONS PER MINUTE
- h — ENTHALPY, BTU PER POUND
- F — TEMPERATURE, °F
- P — PRESSURE, PSIA
- " HGA — PRESSURE, INCHES OF MERCURY ABSOLUTE

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FIGURE 1-8

COMMON 450 psi STEAM SYSTEM

Water Pump Turbine, which are all full condensing units. The 450 psi steam is also used for Condenser Steam Jet Air Ejectors and the Demineralization Plant Caustic Heater.

The 450 psi steam is throttled to 50 psi to provide a small amount of steam to the Ammonia Storage Area and Solution Formulation Area, which is primarily supplied by the Ammonia Plant 50 psi steam header. The condensate from these 50 and 450 psi steam users returns to the Package Boiler Deaerators, completing the common plant area steam cycle. Additional deaerator heating requirements are satisfied by the Ammonia Plant 50 psi steam header with 450 psi steam available as a back-up source. The losses from the common plant areas total 28,490 lb/hr, allowing for make-up from the Ammonia Plant. This loss together with the Urea Plant, Nitric Acid Plant, and the Package Boiler Deaerator vent losses total 39,990 lb/hr, which equals the Demineralization Water Treatment Plant make-up to the Package Boiler Deaerators.

1.6.4.4 Cooling Water

The VNP Plant cooling water is provided by two induced draft wet cooling towers, with a total design capacity of 60,000 gpm (See Figure 1-9). At present, there is a 9,000 gpm excess design capacity. Make-up to the cooling tower basins, for evaporation, blowdown, and wind losses, is provided directly from the Pretreatment Plant Water Clarifier.

1.7 APPLICATIONS OF GEOTHERMAL HEAT TO COMPONENTS AND SYSTEMS

1.7.1 General

The substitution of geothermal for fossil fuel energy at the VNP Plant can best be accomplished by a reduction in fired steam production. The Plant description reveals that the three major steam systems, i.e., 1,500 psi, 450 psi, and 50 psi, are interconnected by a complex system of extraction and back-pressure turbines. Thus, the entire steam supply system must be examined *in toto* to determine where geothermal energy may be applied without upsetting the steam cycle balance.

FIGURE 1-9

1.7.2

Ammonia Plant

In the Ammonia Plant, a reduction in fossil fuel energy can best be accomplished by a reduction in fired 1,500 psi steam. Approximately 109,000 lb/hr of fired steam is generated in the P.C.C. Unit, with the balance being generated by process gas heat recovery (See Figure 1-10). The P.C.C. Unit also provides superheat to the 1,500 psi steam before it goes to the Synthesis Gas Compressor Turbine Drive. This turbine is an extraction type unit and the 450 psi steam system is fed from this unit, with the remaining portion going to full condensing (See Figure 1-6). In order to affect a reduction in the 109,000 lb/hr of fired 1,500 psi steam, it may be necessary to reduce the extraction to 450 psi and increase the amount going to full condensing, while maintaining the horsepower rating of the turbine. Changes in these parameters may require modifications to the P.C.C. Unit, Syn Gas Turbine and Steam Condenser.

In reviewing the Ammonia Plant 450 psi steam system, it becomes obvious that it will be necessary to reduce the 450 psi consumption by the amount of reduced extraction from the Syn Gas Turbine before any meaningful reduction can be made in fossil fuel to the P.C.C. Unit.

An approach to reducing 450 psi steam consumption in the Ammonia Plant would be to replace 450 psi steam users with 50 psi steam users. The increase in 50 psi steam demand would then be met by applying geothermal energy. In particular, the 450 psi turbines exhausting to 50 psi would be replaced with 50 psi turbines going to full condensing. The Refrigeration Compressor Turbine, which uses both 450 psi and 50 psi steam, would be modified to use 50 psi steam exclusively. Also, small full condensing 450 psi turbines may be more economically served by going to electric drives and installing a central geothermal powered turbo-generator. The installation of an electric generating unit, utilizing the geothermal steam source, would not only satisfy any electrical needs for the small turbines taken off the 450 psi system, but would provide the secure power base for the electric control system and critical power requirements. This would prevent a plant shutdown on an outside power utility outage. All of these alternatives require careful evaluation, with the emphasis given to the effects on Ammonia Plant operation and costs of equipment replacement and modification.

1.7.3

Urea Plant

Improvements in the Urea Plant fossil fuel energy consumption can best be accomplished by a reduction in 450

FIGURE 1-10

AMMONIA PLANT
1500 psi STEAM GENERATOR

psi steam utilization. Approximately 41,000 lb/hr of 450 psi steam is used to drive the Hydraulic Supply Pump Turbine (See Figure 1-7). This steam consumption can be reduced by modifying this turbine to a full condensing unit or providing an electric motor to replace it. The 7,290 lb/hr of 450 psi steam used in the desuperheater can be reduced or eliminated by modifying the 150 psi users (urea evaporators) to become 150 psi users in a first stage and providing an alternate source of 150 psi steam for a smaller final stage. The remaining steam users are 50 psi, which can more easily be provided by geothermal energy.

1.7.4 Common Plant Area

The best opportunity for the application of geothermal energy in place of fossil fuel energy, in the common plant area, is in the reduction of 450 psi steam from the Package Boilers (See Figure 1-8). This reduction can be accomplished by utilizing geothermal energy in the Ammonia Storage Area and the Solution Formulation Area, which use primarily 50 psi steam or 450 psi steam throttled to 50 psi. In addition, geothermal energy may be used in the Demineralization Water Treatment Plant to heat caustic, as well as to preheat demineralized make-up water to the Package Boiler Deaerators. Additional Package Boiler Deaerator heating could also be provided by geothermal energy.

1.7.5 Alternative Approach

An alternative approach to the direct application of geothermal energy in the form of hot brine or flashed steam would be the use of a secondary fluid in the application of a binary cycle. The binary fluid would be applied to reduce or eliminate the demand for fossil fired steam generation by augmenting all steam driven equipment with binary expander drivers and using the same binary fluid for process heating. The remaining irreplaceable steam requirements, such as process steam, would be provided by existing process gas heat recovery boilers. This approach might require more capital investment than the one outlined in the previous sections, however, only further cost-benefit analysis can determine its economic feasibility.

1.7.6 Improvements in Plant Reliability

Plant presently consumes about 25-27 million standard cubic feet (scf) of natural gas per day supplied by the Southern California Gas Company. About 60 percent of the natural gas is used as ammonia feedstock and fuel for the primary gas reform. For steam production approximately 10 million scf of natural gas is consumed per day for

production of 1,500 psi and 450 psi steam. It is this 10 million scfd that is subject to curtailment for up to 250 days per year. It is fossil fuel curtailment, now and in the future, that represents the single largest impact on VNP plant reliability.

When implemented, natural gas curtailment will occur with as little as one hour notice. This will require that alternate sources of fossil fuel be kept in "hot standby" and be brought on line to prevent interruption in the steady state plant operation. At present, \$1,300,000 has been budgeted for the conversion of the Common Area Package Boilers to burn both natural gas and fuel oil. This modification includes the addition of fuel oil storage, transfer, and heating facilities along with all associated piping and utilities. The California Public Utilities Commission has not required VNP to modify the Ammonia Plant P.C.C. Unit to fire fuel oil because of the limited size of the fire box. However, if such a requirement is imposed in the future, it will require major modifications to, or even replacement of, the P.C.C. Unit. This modification would require complete Ammonia Plant shutdown at great expense to VNP.

The elimination of all fossil fuel steam production would greatly improve the VNP Plant reliability, by removing the threat of fossil fuel curtailment if the implementation of geothermal heat in place of fossil fuel heat proves to be cost effective.

The loss of electrical power provided by the Imperial Irrigation District to the VNP plant has a devastating effect on plant operation. A complete plant shutdown condition requires 40 hours to resume full production and energy consumption during this period, including natural gas feedstock, is substantially equivalent to "on stream" rates. The need for a reliable source of electrical power as a back up for vital loads has been pointed out by the plant operating personnel. Several schemes will be considered in the detailed engineering analysis.

1.8 SITE CONSIDERATIONS

1.8.1 General

The VNP Plant site is situated on 70 acres of level agricultural land just outside the limits of the city of El Centro

the Imperial County seat. Limits of the plant site are defined by the fenceline around the plant shown in Figure 1-11. The plant is bounded by asphalt paved roads on the south and east, an agricultural drainage ditch on the north, and the Southern-Pacific Railroad right-of-way on the west.

Climatic conditions at the plant site are generally hot and arid with light winds.

Tie-in to the local power grid is made through Imperial Irrigation District switch gear located in the front of the plant on the southern boundary.

Two potential rights-of-way exist for brine transmission between the Heber Reservoir and the VNP Plant. The Southern-Pacific Railroad right-of-way passes approximately four-tenths of a mile east of the proposed 50 MW Geothermal Plant site, while the Dogwood Road right-of-way passes approximately four-tenths of a mile west of the same proposed plant site and through the presently developed geothermal field.

Figure 1-12 is an area plot plan showing major equipment locations in the Ammonia Plant area. The three largest steam turbine driven compressors in the plant are located along the access road on the east battery limits. The remaining steam turbines are scattered within the Ammonia Plant area.

A geothermal plant site can be located on a two acre site adjacent to the Ammonia Plant area providing easy access to the three large turbines. Additional cooling tower capacity can be added adjacent to the existing auxiliary cooling tower.

FIGURE I-11

Section 2

PRELIMINARY ECONOMIC EVALUATION

2.1 INTRODUCTION

A preliminary economic evaluation was completed to determine the overall economic feasibility of substituting geothermal energy for fossil fuel energy at the VNP Plant. The evaluation was completed by comparing the energy cost savings incurred by geothermal energy substitution with the capital costs required for mechanical modifications to the plant. Process modifications were not considered in this evaluation. The energy cost savings were calculated by factoring the predicted geothermal brine costs and fossil fuel costs by the net efficiencies for the existing steam cycle and a proposed geothermal cycle. Capital cost estimates were based on a modified "GEOCOST" computer program developed by Battelle Northwest Laboratories.

2.2 GEOHERMAL FLUID PRICING

One requirement of this study is to determine the potential cost savings that will be incurred by replacing fossil fuel energy with geothermal energy in the VNP plant. Therefore, an accurate prediction of brine pricing over the study period is essential.

The following scenario for brine pricing on the Heber Reservoir was assumed:

Brine pricing will consist of a demand charge and a usage charge. The demand charge will be assessed for the hook-up to the wellhead regardless of the brine usage. The usage charge will reflect actual brine flows. The demand charge will escalate with a cost index reflecting costs for exploration and reservoir development, while the usage charge will escalate with the cost of other industrial fuels. Prices will be structured to recover the cost of exploration and resource development, while providing a reasonable rate of return. The reservoir manager will be selling only the rights to the thermal energy and will maintain the rights to the brine; therefore brine inventory must be maintained. The unit of sale will be BTU/HR and brine will be priced on a cost per million BTU basis. The BTU's will be measured between the actual brine inflow and a reference temperature. The reference temperature will be 160°F for single-phase brine and 200°F for

two-phase brine. The brine temperature at the reinjection wellhead will have to be maintained above 160°F.

Studies done by Stanford Research Institute on the economics of hydrothermal resources indicate that probable pricing of hot water resources in the Imperial Valley (175°C to 200°C) will be in the range of 20 to 27 mills/kwh based on 15 percent and 20 percent discounted cash flow rates of return for private developers, respectively. These are wellhead prices and include both demand and usage charges.

Assuming a reasonable value of 25 mills/kwh for hot water resources and using brine-to-energy conversion factors from work done by Holt/Procon for the Heber Reservoir, of 139 lb/kwh for a binary cycle and 200 lb/kwh for a flash steam cycle, the most probable brine prices in \$/10⁶ BTU are calculated as:

Single-Phase Brine

$$\frac{\$.025}{\text{kwh}} \times \frac{\text{kwh}}{139 \text{ lbs}} \times \frac{\text{lb}}{205 \text{ BTU}} \times \frac{10^6}{10^6} = \frac{\$0.90}{10^6 \text{ BTU}}$$

Two-Phase Brine

$$\frac{\$.025}{\text{kwh}} \times \frac{\text{kwh}}{200 \text{ lbs}} \times \frac{\text{lb}}{165 \text{ BTU}} \times \frac{10^6}{10^6} = \frac{\$0.75}{10^6 \text{ BTU}}$$

A computer model for exploration and reservoir development on the Heber Reservoir was made utilizing the "GEOCOST" program to determine geothermal fluid prices based on drilling and exploration data and thereby to determine the most probable split between demand and usage charges for the total brine prices calculated above. The Reservoir Data used in the model is shown in Table 2-1.

Two reservoir financing options were used to bracket a reasonable development cost:

- (A) 81% Stockholders' Equity
 - 19% Long-Term Debt
 - 8% Bond Interest
 - 15% Return on Equity
- (B) 100% Stockholders' Equity
 - 20% Return on Equity

Table 2-1

RESERVOIR DATA

Average well life = 10 years
Well flow rate = 440,000 lb/hr
Fraction of spare wells = 0.2
Fraction of dry wells = 0.2
Ratio of production wells to injection wells = 2
Reservoir well spacing = 20 acres
Cost of drilling one production well = \$300,000 (DEC '75)
Cost of drilling one dry well = \$300,000 (DEC '75)
Cost of drilling one injection well = \$300,000 (DEC '75)
First year of operation = 1980
Property tax rate = 0.0232
Property insurance rate = 0.0019
Plant operating life = 20 years
Royalty payments = 10%
Geothermal brine temperature at the wellhead = 360°F
Intangible drilling costs = 0.512
Distance from plant to production field = 2.5 miles
Distance from plant to reinjection field = 1 mile
Plant availability = 75%
Federal Income Tax rate = 0.48
State Income Tax rate = 0.09

Option (A) is based on the consolidated balance sheet in the 1976 Annual Report of a major lease holder on the Heber Reservoir. Option (B) is a classic treatment for capital investment analyses. The cost of brine computed reflects both the field development costs and the field operating costs incurred by the lease holder.

The costs for the transmission and disposal systems were assumed to be shared by the lease holder and VNP. All costs associated with the piping systems between the reservoir and the plant were assigned to VNP. The costs for connecting wells within the field were assigned to the lease holder. The binary cycle plant will require a downhole pump for each well to pressurize the brine and prevent it from flashing. A cost of \$100,000 per pump was assumed based on data obtained from pump manufacturers. The downhole pumping costs were assigned to the lease holder.

The flash steam plant was assumed to use two-phase brine which is allowed to flash in the well casing and is transmitted to the VNP Plant under its own pressure. The single-phase brine requires a booster pump to transmit the brine from the wellhead to the VNP Plant without flashing. Transmission pumping costs for the single-phase brine were assigned to the lease holder.

The difference in enthalpies between the wellhead temperature (360°F) and the reference temperatures are 165 BTU/lb for two-phase brine (200°F reference) and 205 BTU/lb for single-phase brine (160°F reference). Using these enthalpies and the "GEOCOST" Program Reservoir Model, the cost of brine as a function of brine flow was calculated for the two reservoir financing options. The results of the computer analysis are shown in Figures 2-1 and 2-2.

Figure 2-1 shows the cost of single-phase brine for flows up to seven million pounds per hour. The assumed price of \$0.90/10⁶ BTU falls between the curves for the two reservoir financing options, which suggests that it is a reasonable price. The lower curve (81% equity, 19% bonds) levels out at \$0.76/10⁶ BTU in December 1977 dollars. Assuming the cost is based on a fully developed reservoir, where the cost of brine has leveled, we shall assume that the demand charge is \$0.76/10⁶ BTU, which will give a reasonable return on equity regardless of brine usage. The difference between this demand charge and the assumed price is \$0.14/10⁶ BTU, which we shall call the usage charge. Thus the demand charge is 84 percent of the total brine cost, which appears to be reasonable.

BRINE COST (DEC' 77)
(DOLLARS PER MMBTU)

SINGLE-PHASE BRINE

FIGURE 2-1

TWO-PHASE BRINE

86
BRINE COST (DEC' 77)
(DOLLARS PER MMBTU)

FIGURE 2-2

Figure 2-2 shows the cost of two-phase brine for flows up to seven million pounds per hour. The lower curve (81% equity, 19% bonds) levels out at $\$0.80/10^6$ BTU which is close to the assumed price of $\$0.75/10^6$ BTU. Using the same criteria applied to determine the demand and usage charges for the single-phase brine, and assuming for the moment that the lease holder's price will be formulated on an equal bus-bar cost basis to encourage the development of flash steam geothermal plants on the Heber Reservoir, we have assigned a demand charge equal to 84 percent of the total assumed brine cost of $\$0.75/10^6$ BTU. Thus the demand charge for two-phase brine is fixed at $\$0.63/10^6$ BTU and the usage charge is fixed at $\$0.12/10^6$ BTU.

2.3 ENERGY COSTS

In any study of alternative energy cost effectiveness it is essential to establish a conservative model of conventional energy costs during the study period. Each of the conventional energy sources available to the VNP Plant was evaluated for constant dollar cost escalations over the study period and appear in Figure 2-3. The following assumptions were made in determining the constant dollar fuel costs:

1. Purchased electricity from the off-site utility will increase 20 percent overall between 1977 and 1985. This 20 percent increase over an eight-year period is equivalent to a 2.3 percent escalation rate per year. Between 1985 and 1990, off-site electricity real costs will be constant. After 1990, the cost of off-site electricity becomes confused by the number of scenarios involving the development of conventional and alternative energy sources. However, since the economic evaluation will be based on a ten-year period from 1980 to 1989, there is no requirement to predict off-site electrical costs beyond the year 1990.

(The assumptions for the cost of purchased electricity do not reflect changes in the present declining block rate structure now being considered by the CERDC and the CPUC, which would greatly increase electrical costs to the VNP Plant, or the ability of the local utility (Imperial Irrigation District) to supply additional electrical demand requirements to the plant.)

2. Fuel oil costs will increase at a rate of five percent per year reflecting the demand for a diminishing resource.
3. Natural gas prices will approach the price of fuel oil between 1977 and 1980 at rates of 18.5 percent in 1978 and 23.5 percent in 1979 and 1980. After 1980, natural

FIGURE 2-3

gas costs will escalate at five percent per year, following fuel oil prices. Since the natural gas for steam production in the VNP Plant could be heavily curtailed by the California Public Utilities Commission during the study period, it will not be considered further in this economic analysis.

4. Single-phase and two-phase brine costs will be divided into demand and usage charges as described in Section 2.2. The demand charges will remain constant on a constant dollar basis. The usage charges will reflect the increase in fuel oil costs and will escalate at the rate of five percent per year on a constant dollar basis.

A more revealing method of comparing alternative fuel costs is to incorporate energy conversion efficiencies into the respective energy costs appearing in Figure 2-3 and compare converted constant dollar fuel costs. The results of this comparison are shown in Figure 2-4. A conversion efficiency of 74 percent for purchased electricity (about 1 kwh = 1 hp) was assumed. Fuel oil and natural gas conversion efficiencies for the existing plant steam cycle of 17.4 percent (calculated in Appendix B) were used. Geothermal energy conversion efficiencies were calculated from the results of "GEOCOST" computer runs. The single-phase brine conversion efficiency, based on an isobutane binary cycle, was calculated to be 9.7 percent. The two-phase brine conversion efficiency, based on a flash steam cycle, was calculated to be 10 percent.

The converted constant dollar fuel costs in Figure 2-4 indicate that two-phase brine will be the cheapest form of future energy available to VNP, with purchased electricity and single-phase brine a close second and third respectively.

This energy cost comparison does not include the capital cost of building the new plant facilities required to convert these forms of energy to useful work, which will have an affect on determining which energy source is truly the most economical for VNP.

2.4 GEOTHERMAL CAPITAL COST MODELS

2.4.1 Introduction

In determining the economic feasibility of replacing fossil fuel, as a source of energy in the VNP

FIGURE 2-4

Plant, with geothermal energy, it is necessary to make a capital cost and thermodynamic model of the geothermal energy plant. The model is useful in several areas of the study, such as estimating the capital cost of modifying the plant, estimating the demand charge for comparing individual equipment replacement options, and calculating the internal rate of return to VNP as a function of the geothermal plant size.

2.4.2 Computer Model

The computer model used for the economic and thermodynamic analysis of the VNP Geothermal Plant was a modified version of the "GEOCOST" program developed by Battelle Pacific Northwest Laboratories to analyze geothermal electric production costs. The computer model was used to estimate the costs of a 5, 10, 15, 20, 25, and 30 gross megawatt plant for both the binary and flash steam power cycles.

The steam cycle is a two-stage flash process driving low pressure saturated steam turbines as shown in Figure 2-5. The geothermal fluid, which is allowed to flash in the well casing, contains 2.5 percent steam at the wellhead and is transmitted to the VNP Plant under its own pressure as two-phase flow.

The binary cycle assumes isobutane as the working fluid, driving high pressure vapor expanders in a sub-critical rankine power cycle as shown in Figure 2-6. The geothermal fluid, which is pressurized in the well casing using a downhole pump, is transmitted to the VNP Plant by a booster pump as single-phase flow.

The "GEOCOST" capital cost estimates were modified to eliminate unnecessary equipment costs and to reflect cost increases resulting from multiple turbine applications. The modifications to the capital cost estimates are discussed in more detail in the following section.

The following categories of equipment and other costs were included in the flash steam plant capital cost estimates:

- Piping, insulation, and tanks
- Turbines
- Flashers
- Miscellaneous process support equipment

TWO-STAGE FLASH STEAM PLANT

FIGURE 2-5

SUB-CRITICAL BINARY FLUID CYCLE PLANT

FIGURE 2-6

- Instrumentation and controllers
- Electrical support equipment
- Condensers
- Installation testing
- Buildings, foundations and support equipment
- Gas ejectors (steam-driven)
- Cooling Water Pump
- Flash Water Reinjection Pump
- Cooling Tower Reinjection Pump
- Cooling Tower System
- Engineering and design
- Administration and indirect costs
- Geothermal fluid transmission system
- Geothermal fluid disposal system
- Other operating costs

The "GEOCOST" cost estimates (in December 1975 dollars)* were escalated by 11.8 percent (based on CPI records and projections) to obtain December 1977 dollars. The total capital cost for each flash steam plant size is shown in Table 2-12.

The following categories of equipment and other costs were included in the binary plant capital cost estimates:

- Piping, insulation, and tanks
- Turbines
- Vapor generator (boiler)
- Miscellaneous process support equipment
- Instrumentation and controllers
- Electrical support equipment
- Condensers
- Installation testing
- Buildings, foundations, and support equipment
- Binary fluid pumps

*The present "GEOCOST" program performs all economic calculations in terms of December 1975 dollars.

- Cooling tower system
- Engineering and design
- Administration and indirect costs
- Geothermal fluid transmission system
- Geothermal fluid disposal system
- Other operating costs

The "GEOCOST" cost estimates (in December 1975 dollars) were escalated by 11.8 percent (based on CPI records and projections) to obtain December 1977 dollars. The total capital costs for each binary cycle plant size is shown in Table 2-11.

2.4.3 Modifications to the Capital Cost Estimates

The "GEOCOST" capital cost estimates were modified to eliminate unnecessary equipment costs which are more typical of power plants, such as an overhead crane for a turbine-generator set and a switchyard for large-scale power transmission. The "GEOCOST" program calculates the cost of one turbine-generator set for each plant size, therefore the capital cost estimates for turbines and associated piping were modified to eliminate the cost of a generator and to reflect the fact that the VNP Plant has many relatively small turbine applications rather than one large turbine.

Cooling tower capital cost estimates were also modified to reflect the fact that present cooling tower capacity can be credited against the cooling tower requirements, calculated in the thermodynamic model of the geothermal plant, by comparing the net thermal efficiencies of the present steam cycle and the proposed geothermal plant thermal cycle.

2.4.3.1 Turbine Costs

Budget quotations for low pressure saturated steam turbines, for flash plant equipment drives, were requested and received from three turbine manufacturers: Turbodyne, Elliott, and Terry. The steam turbine capital costs were converted from April 1977 dollars to December 1975 dollars* and compared to the cost of a totally installed turbogenerator set using the "GEOCOST" capital cost equation. From the comparison of vendor information and the "GEOCOST" equation, shown in Figures 2-7 and 2-8, a conservative

*The present "GEOCOST" program performs all economic calculations in terms of December 1975 dollars.

FLASH PLANT STEAM TURBINES (0-1500 HP)

•--VENDOR QUOTATIONS (DEC'75\$'s)

"GEOCOST" EQUATION (DEC'75 \$'S)

ASSUMED COST (DEC'75 \$'S)

FIGURE 2-7

FLASH PLANT
STEAM TURBINES
(0-15,000 HP)

•--VENDOR QUOTATIONS (DEC'75 \$'s)

"GEOCOST" EQUATION (DEC'75 \$'s)

ASSUMED COST (DEC'75 \$'s)

49
INSTALLED COST, \$ 10³

FIGURE 2-8

estimate of total installed costs for steam turbines was made as a function of turbine size. The cumulative installed turbine costs for each plant size are tabulated along with the "GEOCOST" estimate of the cost of a single turbo-generator set of the same size.

Table 2-2

FLASH STEAM TURBINE COSTS

<u>Plant Size</u>	<u>GEOCOST**</u>	<u>Assumed Cumulative Turbine Costs</u>	<u>No. of Turbines</u>
(MW)	(DEC 75 \$'s)	(DEC 75 \$'s)	
5	1,641,000	1,570,000	1
10	2,616,000	2,725,000	2
15	3,444,000	4,295,000	3
20	4,190,000	5,925,000	3
25	4,880,000	7,495,000	4
30	5,528,000	10,530,000	12

**Based on one turbine-generator set

From Table 2-2 it can be seen that the costs assumed for turbines are greater than what "GEOCOST" would have predicted for a comparable size power plant, thereby accounting for the added cost of multiple turbines in a process plant application.

The binary plant turbine costs were handled in a likewise manner. Budget quotations for radial inflow binary vapor expanders, for the binary plant equipment drives, were requested and received from three vapor expander manufacturers: Rotoflow, Mafi-Trench, and Lotema. The vapor expander capital costs were converted from April 1977 dollars to December 1975 dollars* and compared to the cost of a totally installed turbo-generator set using the "GEOCOST" capital cost equation. From the comparison of vendor information and the "GEOCOST" equation, shown in Figures 2-9 and 2-10, a conservative estimate of total installed costs for binary expanders was made as a function of expander size. The cumulative installed expander costs for each plant size are tabulated along with the "GEOCOST" estimate of the cost of a single turbo-generator set of the same size.

*The present "GEOCOST" program performs all economic calculations in terms of December 1975 dollars.

BINARY PLANT
TURBO - EXPANDERS
(0-1500 Hp)

FIGURE 2-9

BINARY PLANT TURBO-EXPANDERS (0-15,000 Hp)

FIGURE 2-10

Table 2-3

BINARY EXPANDER COSTS

<u>Plant Size</u>	<u>GEOCOST*</u>	<u>Assumed Cumulative Expander Costs</u>	<u>No. of Expanders</u>
(MW)	(DEC 75 \$'s)	(DEC 75 \$'s)	
5	864,000	660,000	1
10	1,491,000	1,330,000	2
15	2,355,000	1,990,000	3
20	2,689,000	3,040,000	3
25	3,553,000	3,700,000	4
30	8,562,000	5,405,000	12

*Based on one expander-generator set.

From Table 2-3 and Figures 2-9 and 2-10 it can be seen that the "GEOCOST" capital cost estimates for vapor expanders are high compared to the vendor budget quotations, even at the largest plant size, where we compare the cost of twelve vapor expanders to one expander-generator set.

2.4.3.2 Piping Costs

The "GEOCOST" program calculates the total piping capital costs for a geothermal power plant based on one turbine-generator set. With multiple turbine applications, inherent in a chemical processing plant, it was necessary to estimate the impact on total plant piping costs of adding additional turbine drivers. For the purposes of this study, it was assumed that each additional flash steam turbine increases plant piping costs by 5 percent and each additional vapor expander increases plant piping costs by 3 percent. Therefore, for the cost estimating cases run, the "GEOCOST" program piping costs were multiplied by the following factors to account for additional turbine piping costs.

Table 2-4

TURBINE PIPING COST FACTORS

<u>Plant Size</u>	<u>No. of Turbines</u>	<u>Flash Plant Cost Factor</u>	<u>Binary Plant Cost Factor</u>
(MW)			
5	1	1	1
10	2	1.05	1.03
15	3	1.10	1.06
20	3	1.10	1.06
25	4	1.15	1.09
30	12	1.55	1.33

2.4.3.3 Cooling Tower Costs

The "GEOCOST" program estimates the total installed cost of providing cooling towers to provide the heat rejection load calculated in the thermodynamic plant model. However, since the existing VNP Plant has cooling tower capacity, it will only be necessary to provide an incremental increase in capacity to reflect the difference in net thermal cycle efficiencies between the two plant cycles. In other words, if the present steam cycle and the proposed geothermal cycle operated at the same net thermal efficiency the total cooling tower requirement would remain constant. However, since the geothermal cycle operates at a lower temperature, and therefore a lower thermal efficiency, the geothermal cycle will reject more heat per horsepower output than the existing steam cycle. Therefore, an incremental cooling tower capacity will be required to handle the increased heat rejection load.

In Appendix A an equation is derived for calculating the fraction of the total cooling tower capacity, given by the "GEOCOST" thermodynamic model, required to meet the incremental heat load increase. It is assumed that the capital cost estimate for cooling towers is proportional to the cooling tower capacity. Therefore, we will factor the cooling tower capital cost estimate, by the fraction of the total cooling tower capacity required, to determine the incremental cooling tower cost.

Assuming a net thermal cycle efficiency for a geothermal plant of 12 percent and using the VNP Plant steam cycle net thermal efficiency of 17 percent calculated in Appendix B, the incremental cooling tower cost fraction is:

$$\text{Cooling Tower Cost Fraction} = 1 - \frac{[(1-0.17)(0.12)]}{[(1-0.12)(0.17)]} = 0.33$$

Therefore, 33 percent of the "GEOCOST" capital cost estimates for cooling towers are used for each plant size.

2.5 PRELIMINARY ECONOMIC FEASIBILITY

To evaluate the economic feasibility of substituting geothermal energy at the VNP Plant, a comparison was made of capital investment costs and fuel cost savings for plant modifications ranging between 5 MW and 30 MW gross capacities for both binary and flash steam geothermal plants. Capital cost estimates for plant modifications were made, as described

in Section 2.4, using the modified "GEOCOST" program. Yearly energy cost savings were calculated for the period 1980 through 1989 by comparing the energy costs and net thermal efficiencies of the existing plant and an alternative geothermal plant of the same capacity using the following equation:

$$S = \frac{C}{\frac{eg}{ef}} \left[a \frac{eg}{ef} - b \right]$$

where:

- S = Yearly cost savings, \$/YR
- C = Yearly geothermal plant net power output, BTU/YR
- ef = Fossil plant net thermal efficiency
- eg = Geothermal plant net thermal efficiency
- a = Cost of fossil fuel, \$/10⁶ BTU
- b = Cost of geothermal fuel, \$/10⁶ BTU

and C can be calculated by:

$$C = (\text{Net Power, KW}) \left(\frac{3412.2 \text{ BTU}}{\text{KWH}} \right) \left(\frac{8760 \text{ HR}}{\text{YR}} \right) (\text{Capacity Factor})$$

Yearly energy cost savings were calculated using the constant dollar yearly fuel costs in Figure 2-3. The net thermal cycle efficiency of 17.4 percent for the existing fossil fuel plant, calculated in Appendix B, was used for this calculation along with geothermal plant net thermal cycle efficiencies of 9.7 percent for the binary cycle and 10 percent for the flash plant cycle, as calculated by the "GEOCOST" geothermal plant thermodynamic model. The yearly energy cost savings are shown for the period 1980 through 1989 in Tables 2-5 and 2-6 for binary and flash steam cycle geothermal plants as a function of gross installed geothermal capacity. The net geothermal capacities can be calculated using the auxiliary power requirements for each geothermal cycle with the following equation:

$$\text{Net Capacity} = \text{Gross Capacity} (1 - \% \text{ Aux. Power})$$

The auxiliary power requirement for each geothermal flash steam cycle is 12 percent, while the geothermal binary cycle requires 20 percent auxiliary power.

Payout periods for financing and repayment of bank loans were calculated for each geothermal plant size. Examples of 25 MW binary and flash steam geothermal plants appear in Tables 2-7 and 2-8. Capital costs for the plant

Table 2-5

Annual Energy Cost Savings for Geothermal
Binary Cycle Plants, \$ Millions (Constant \$ 1977)

<u>Year</u>	<u>Installed Geothermal Capacity</u>					
	<u>5 MW</u>	<u>10 MW</u>	<u>15 MW</u>	<u>20 MW</u>	<u>25 MW</u>	<u>30 MW</u>
1980	0.772	1.534	2.292	3.049	3.808	4.569
1981	0.850	1.689	2.524	3.358	4.194	5.032
1982	0.918	1.825	2.727	3.628	4.531	5.436
1983	1.006	2.000	2.988	3.976	4.965	5.957
1984	1.094	2.175	3.249	4.323	5.399	6.477
1985	1.182	2.349	3.511	4.671	5.833	6.998
1986	1.290	2.563	3.830	5.095	6.363	7.634
1987	1.387	2.757	4.120	5.481	6.845	8.212
1988	1.495	2.971	4.439	5.906	7.375	8.849
1989	1.612	3.204	4.787	6.369	7.954	9.543

Table 2-6

Annual Energy Cost Savings for Geothermal
Steam Cycle Plants, \$ Millions (Constant \$ 1977)

<u>Year</u>	<u>Installed Geothermal Capacity</u>					
	<u>5 MW</u>	<u>10 MW</u>	<u>15 MW</u>	<u>20 MW</u>	<u>25 MW</u>	<u>30 MW</u>
1980	0.965	1.913	2.845	3.795	4.728	5.685
1981	1.042	2.066	3.073	4.099	5.114	6.140
1982	1.129	2.238	3.329	4.440	5.518	6.652
1983	1.215	2.410	3.585	4.782	5.942	7.163
1984	1.302	2.582	3.841	5.123	6.388	7.675
1985	1.399	2.773	4.125	5.503	6.856	8.244
1986	1.495	2.965	4.410	5.882	7.348	8.812
1987	1.601	3.175	4.723	6.300	7.864	9.437
1988	1.717	3.405	5.064	6.755	8.406	10.120
1989	1.833	3.634	5.406	7.210	8.974	10.802

Table 2-7

FINANCING AND REPAYMENT OF BANK LOAN FOR 25 MW BINARY CYCLE PLANT

<u>Year</u>	<u>Beginning Outstanding Debt</u>	<u>Interest @ 8%</u>	<u>Insurance & Taxes @ 2.51%</u>	<u>Energy Cost Savings</u>	<u>Ending Outstanding Debt</u>
1977	7,213,000	577,000	181,000	-----	7,971,000
1978	15,184,000	1,215,000	362,000	-----	16,761,000
1979	23,975,000	1,918,000	543,000	-----	26,436,000
1980	26,436,000	2,115,000	543,000	3,808,000	25,286,000
1981	25,286,000	2,023,000	516,000	4,194,000	23,631,000
1982	23,631,000	1,890,000	489,000	4,531,000	21,479,000
1983	21,479,000	1,718,000	462,000	4,965,000	18,694,000
1984	18,694,000	1,496,000	435,000	5,399,000	15,225,000
1985	15,225,000	1,218,000	407,000	5,833,000	11,018,000
1986	11,018,000	881,000	380,000	6,363,000	5,916,000
1987	5,916,000	473,000	353,000	6,845,000	LOAN REPAYED

Table 2-8

FINANCING AND REPAYMENT OF BANK LOAN FOR 25 MW STEAM CYCLE PLANT

<u>Year</u>	<u>Beginning Outstanding Debt</u>	<u>Interest @ 8%</u>	<u>Insurance & Taxes @ 2.51%</u>	<u>Energy Cost Savings</u>	<u>Ending Outstanding Debt</u>
1977	8,473,000	678,000	213,000	-----	9,364,000
1978	17,837,000	1,427,000	425,000	-----	19,689,000
1979	28,163,000	2,253,000	638,000	-----	31,054,000
1980	31,054,000	2,484,000	638,000	4,728,000	29,448,000
1981	29,448,000	2,356,000	606,000	5,114,000	27,296,000
1982	27,296,000	2,184,000	574,000	5,518,000	24,536,000
1983	24,536,000	1,963,000	542,000	5,942,000	21,100,000
1984	21,100,000	1,688,000	510,000	6,388,000	16,910,000
1985	16,910,000	1,353,000	479,000	6,856,000	11,885,000
1986	11,885,000	951,000	447,000	7,348,000	5,935,000
1987	5,935,000	475,000	415,000	7,864,000	LOAN REPAYED

modifications were assumed to be incurred uniformly over a three-year construction period beginning in 1977. Thus the beginning outstanding debt in 1977 is one-third of the initial capital investment. A loan interest rate of 8 percent was assumed along with a property insurance rate of 0.19 percent and a property tax rate of 2.32 percent. The insurance and taxes are based on 20-year straight-line depreciation of the initial capital investment. For the three years prior to plant operation, the insurance and taxes are equal to:

$$CI \times 0.0251 \times [(3 - (1979 - \text{YEAR})) / 3]$$

where CI is the initial capital investment. For the years of plant operation, the insurance and taxes are equal to:

$$CI \times 0.0251 \times [(2000 - \text{YEAR}) / 20]$$

The energy cost savings are taken directly from Tables 2-5 and 2-6. The ending outstanding debt for each year is equal to the beginning outstanding debt for the year, plus the interest, plus the insurance and taxes, minus the energy cost savings. The loan is completely repaid during the year when the energy cost savings become greater than the sum of the debt plus interest plus insurance and taxes.

Present worth and internal rate of return calculations were done for each geothermal plant size. Examples of 25 MW binary and flash steam geothermal plants appear in Tables 2-7 and 2-8. The net savings shown is the difference between the energy cost savings and the taxes and insurance. To compute the internal rate of return, the present worth of the net savings must be compared with the present worth of the initial investment. Since VNP requires at least a 10 percent rate of return (in constant dollars) over the first 10 years of operation for major capital investments, the net present worth of the cash flows are first calculated at a fixed 10 percent rate of return. A positive net present worth indicates that the actual rate of return is higher than 10 percent. The actual internal rate of return is calculated by trial and error, until the net positive present worth approaches zero at the interest rate chosen. The actual internal rate of return for the 25 MW binary plant, shown in Table 2-9, is calculated to be 17.3 percent over the first 10 years of operation; while the actual internal rate of return for the 25 MW flash plant, shown in Table 2-10, is calculated to be 17.6 percent over the first 10 years of operation. Financial summaries for each binary and steam cycle plant size considered appear in Tables 2-11 and 2-12.

Table 2-9

PRESENT WORTH AND INTERNAL RATE OF RETURN FOR 25 MW BINARY CYCLE PLANT

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Energy Cost Savings</u>	<u>Net Savings</u>	<u>Present Worth Factor @ 10%</u>	<u>Present Worth @ 10%</u>	<u>Present Worth Factor @ 17.3%</u>	<u>Present Worth @ 17.3%</u>
1980	543,000	3,808,000	3,265,000	0.909	2,968,000	0.852	2,782,000
1981	516,000	4,194,000	3,678,000	0.826	3,040,000	0.726	2,671,000
1982	489,000	4,531,000	4,042,000	0.751	3,037,000	0.619	2,502,000
1983	462,000	4,965,000	4,503,000	0.683	3,076,000	0.528	2,376,000
1984	435,000	5,399,000	4,964,000	0.621	3,083,000	0.450	2,232,000
1985	407,000	5,833,000	5,426,000	0.564	3,063,000	0.383	2,079,000
1986	380,000	6,363,000	5,983,000	0.513	3,070,000	0.327	1,954,000
1987	353,000	6,845,000	6,492,000	0.467	3,029,000	0.278	1,807,000
1988	326,000	7,375,000	7,049,000	0.424	2,990,000	0.237	1,672,000
1989	299,000	7,954,000	7,655,000	0.386	2,951,000	0.202	1,548,000
TOTAL:					30,307,000		21,623,000
Initial Investment:					(21,640,000)		(21,640,000)
Net Present Worth:					8,667,000		(17,000)
Internal Rate of Return:							17.3%

Table 2-10

PRESENT WORTH AND INTERNAL RATE OF RETURN FOR 25 MW STEAM CYCLE PLANT

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Energy Cost Savings</u>	<u>Net Savings</u>	<u>Present Worth Factor @ 10%</u>	<u>Present Worth @ 10%</u>	<u>Present Worth Factor @ 17.6%</u>	<u>Present Worth @ 17.6%</u>
1980	638,000	4,728,000	4,090,000	0.909	3,718,000	0.850	3,478,000
1981	606,000	5,114,000	4,508,000	0.826	3,726,000	0.723	3,260,000
1982	574,000	5,518,000	4,944,000	0.751	3,714,000	0.615	3,040,000
1983	542,000	5,942,000	5,400,000	0.683	3,688,000	0.523	2,823,000
1984	510,000	6,388,000	5,878,000	0.621	3,650,000	0.445	2,613,000
1985	479,000	6,856,000	6,379,000	0.564	3,600,000	0.378	2,411,000
1986	447,000	7,348,000	6,901,000	0.513	3,541,000	0.321	2,219,000
1987	415,000	7,864,000	7,449,000	0.467	3,475,000	0.273	2,036,000
1988	383,000	8,406,000	8,023,000	0.424	3,403,000	0.232	1,865,000
1989	351,000	8,974,000	8,623,000	0.386	3,325,000	0.198	1,704,000
TOTAL:					35,839,000		25,449,000
Initial Investment:					(25,420,000)		(25,420,000)
Net Present Worth:					10,419,000		29,000
Internal Rate of Return:							17.6%

Table 2-11

FINANCIAL SUMMARY - BINARY CYCLE PLANTS (CONSTANT \$ 1977)

Plant Size (MW)	Year Bank Loan Repayed With Energy Cost Savings	Capital Investment for Geothermal Conversion (\$ Millions)	Present Worth of Energy Cost Savings Over First 10 Years @ 10% (\$ Millions)	Incremental Benefit-Cost Ratio	Internal Rate of Return Over First 10 Years %
5	1991	6.2	5.9	0.95	9.1
10	1989	10.5	12.0	1.42	12.7
15	1988	14.1	18.1	1.69	15.4
20	1988	18.5	24.1	1.36	15.7
25	1987	21.6	30.3	2.00	17.3
30	1988	27.6	36.2	0.98	15.8

Table 2-12

FINANCIAL SUMMARY - STEAM CYCLE PLANTS (CONSTANT \$ 1977)

Plant Size (MW)	Year Bank Loan Repayed With Energy Cost Savings	Capital Investment for Geothermal Conversion (\$ Millions)	Present Worth of Energy Cost Savings Over First 10 Years @ 10% (\$ Millions)	Incremental Benefit-Cost Ratio	Internal Rate of Return Over First 10 Years %
5	1995	9.4	6.8	0.72	3.9
10	1990	13.6	14.1	1.73	10.7
15	1989	18.7	21.2	1.39	12.6
20	1988	22.7	28.5	1.82	14.8
25	1987	25.4	35.8	2.71	17.6
30	1988	33.6	42.8	0.85	15.2

2.6 SUMMARY

All geothermal steam and binary cycle plant sizes considered show internal rates of return exceeding 10 percent with the exception of the 5 MW binary cycle and 5MW steam cycle plants. The capital investments for the steam cycle plants are greater than the capital investments for the same size binary cycle plants, due primarily to higher turbine costs and higher transmission costs for two-phase brine. Therefore the steam cycle plants have slightly smaller internal rates of return, compared to the binary cycle plants, over the first 10 years of operation. The only exception is the 25 MW plant size, where the energy cost savings of the steam cycle plant are sufficient to provide a slightly higher internal rate of return than the binary cycle plant.

Incremental benefit-cost ratios for each plant size also appear in Tables 2-11 and 2-12. These ratios indicate whether each 5 MW increase in plant size is a cost-effective investment satisfying the 10 percent rate of return requirement. Tables 2-11 and 2-12 show that the 30 MW binary cycle and steam cycle plants would be questionable investments, because the incremental benefit-cost ratio is less than 1. This is due primarily to the high capital cost of multiple turbine applications. Therefore, although the 30 MW binary cycle and flash cycle plants would have internal rates of return of 15.8 percent and 15.2 percent, respectively, over the first 10 years of operation, the incremental increases in energy cost savings over the 25 MW plant sizes would not justify the incremental increases in capital investment. Thus, the internal rate of return for this incremental investment will be less than 10 percent over the first 10 years of operation, which would not satisfy the minimum VNP requirement for major capital investments. All other incremental benefit-cost ratios, except the 5 MW binary cycle and steam cycle plants, with their low internal rates of return, are greater than 1 indicating that they are all acceptable capital investments.

2.7 CONCLUSIONS OF THE PRELIMINARY ECONOMIC EVALUATION

The preliminary economic evaluation shows that the substitution of geothermal energy for fossil fuel energy at the VNP plant can be economically feasible for either binary or flash steam cycle plants, if the plant size is at least 10 MW and the capital costs for large plant modifications

can be held down by limiting the number of geothermal turbine substitutions. This result is largely based on the fuel pricing assumptions made for both fossil fuel and geothermal energy, which provide for an increasing constant dollar price differential over the study period as shown in Figure 2-3. The future announcement of the price structure of geothermal fluid contracts on the Heber Reservoir will confirm or refute this assumption.

This preliminary conclusion also assumes that the substitution of geothermal energy will offset an equivalent amount of fossil fuel energy and that each increment of fossil fuel reduction will have the same thermal efficiency as the overall plant thermal efficiency. With the large amount of waste heat input to the VNP Plant steam cycle and the differences in equipment efficiencies in various parts of the plant, neither of these assumptions may prove to be totally correct.

Section 3

ENERGY UTILIZATION EVALUATION

3.1 INTRODUCTION

An energy utilization evaluation was completed to determine the most cost-effective method for substituting geothermal energy for fossil fuel energy at the VNP Plant. The evaluation was completed by assigning a total unit charge rate in \$/Hp-hr to each existing equipment driver in the plant steam cycle, which reflects the levelized operating cost for the period 1980 through 1989, and to each alternative equipment driver in a new power cycle, which reflects both plant modification capital costs and operating costs for the same period. Capital costs for providing the geothermal power cycle are based on the "GEOCOST" computer program, while capital costs for providing the geothermal cycle equipment drivers and the new electric motors are based on budget quotations received from leading equipment manufacturers.

Yearly fuel costs were inflated for this evaluation at the rate of 6.5 percent per year for the ten year period under consideration to more accurately reflect actual expected fuel cost cash flows. The escalated costs of fuel for the period 1980 through 1989 were simplified by calculating a levelized fuel cost in present worth 1980 dollars to facilitate the calculation of energy charges for each equipment driver option. The calculation of levelized fuel costs is shown in Appendix C.

3.2 ENERGY CHARGES FOR EXISTING TURBINES

3.2.1 Introduction

The cost of operating existing steam turbines was calculated to compare continued operation of these turbines against other alternatives available in the future. Energy charges for steam usage have been calculated on a cost per horsepower-hour basis and have been based on the levelized fuel oil cost, calculated in Appendix C, of \$5.90/ MMBTU for the period 1980 through 1989. An additional charge of \$0.50/1000 lb of steam has been added to the steam cost to account for demineralizing condensate. The cost of steam has been based on the energy required to heat the steam from saturated liquid at the condensing pressure to turbine inlet conditions, taking boiler efficiency into account. Energy charges for each turbine have been based on the amount of

usable energy remaining at the turbine exhaust compared to the total energy used to produce the steam. For example, 50 psi backpressure turbines have been charged for the actual amount of energy used in the steam expansion between the inlet conditions and the exhaust conditions, while full condensing turbines have been charged the total steam cost. In addition to conventional backpressure and full condensing turbines, four special cases of extraction, induction, and high backpressure turbines have been calculated, namely the Synthesis Gas Compressor, Refrigeration Compressor, Process Air Compressor, and Hydraulic Supply Pump Turbines. The results of these calculates are shown in Table 3-2.

3.2.2 Steam Cost

The heat added in 450 psi steam production, assuming a boiler efficiency of 76 percent, equals:

$$Q_{\text{ADDED}} = \frac{(1298.6 - 93.34) \text{ BTU/LB}}{0.76} = \frac{1205.26}{0.76} = 1585.9 \text{ BTU/LB}$$

The cost of steam, using a levelized fuel cost of \$5.90/MMBTU and assuming \$0.50/1000 lb for demineralizing costs is:

$$\begin{aligned} \text{Steam Cost} &= \left[\frac{1585.9 \text{ BTU}}{\text{LB}} \times \frac{1000}{1000} \times \frac{\$5.90}{10^6 \text{ BTU}} \right] + \left[\frac{\$0.50}{1000 \text{ lb}} \right] \\ &= \frac{\$9.34}{1000 \text{ lb}} + \frac{\$0.50}{1000 \text{ lb}} = \frac{\$9.85}{1000 \text{ lb}} \end{aligned}$$

3.2.3 Full Condensing Turbines

Since full condensing turbines are charged the total steam cost, it follows that the energy charge in dollars per horsepower-hour is a function of the steam cost and the actual turbine steam rate, namely:

$$(\text{Energy Charge})_{\text{FC}} = \frac{\$9.85}{1000 \text{ lb}} \left[\frac{\text{S.R. lb}}{\text{Hp-hr}} \right] = \frac{\$}{\text{Hp-hr}}$$

The steam rates and energy charges for full condensing turbines are shown in Table 3-2.

3.2.4 Backpressure Turbines

Backpressure turbines in the VNP Plant are designed to exhaust at 70 psia and 360°F. Therefore, assuming a constant exhaust enthalpy for all backpressure turbines of 1211.4 BTU/LB, and with a turbine inlet enthalpy of 1298.6 BTU/LB, the fraction of the total steam cost chargeable to each backpressure turbine is:

$$\frac{1298.6 - 1211.4}{1298.6 - 93.34} = 0.0724 \text{ of the full condensing cost.}$$

The energy charge for backpressure turbines then becomes:

$$\begin{aligned} (\text{Energy Charge})_{BP} &= \frac{\$9.85}{1000 \text{ lb}} \left[\frac{\text{S.R. lb}}{\text{Hp-hr}} \right] [0.0724] \\ &= \frac{\$0.713}{1000 \text{ lb}} \left[\frac{\text{S.R. lb}}{\text{Hp-hr}} \right] = \frac{\$}{\text{Hp-hr}} \end{aligned}$$

The steam rates and energy charges for backpressure turbines are shown in Table 3-2.

The cost chargeable to the steam exhausting from the backpressure turbines can now be calculated as:

$$\begin{array}{rcccl} \text{Backpressure Exhaust} & = & \frac{\$9.85}{1000 \text{ lb}} & - & \frac{\$0.71}{1000 \text{ lb}} & = & \frac{\$9.14}{1000 \text{ lb}} \\ \text{Steam Cost} & & & & & & \end{array}$$

The backpressure turbine exhaust system supplies a low pressure steam system within the VNP Plant referred to as the 50 psi Steam System.

3.2.5 Hydraulic Supply Pump Turbine

The Hydraulic Supply Pump Turbine is a special case of a backpressure turbine with the turbine exhausting at 174 psia rather than 70 psia. Therefore, assuming a turbine exhaust enthalpy of 1251.6 BTU/LB, based on Figure 1-7 and with a turbine inlet enthalpy of 1298.6 BTU/LB, the fraction of the total steam cost chargeable to the Hydraulic Supply Pump Turbine is:

$$\frac{1298.6 - 1251.6}{1298.6 - 93.34} = 0.039 \text{ of the full condensing cost.}$$

With a steam rate of 54.2 lb/Hp-hr, the energy charge for the Hydraulic Supply Pump Turbine then becomes:

$$\begin{aligned} (\text{Energy Charge})_{\text{HSPT}} &= \frac{\$9.85}{1000 \text{ lb}} \left[\frac{\text{S.R. } 1\text{b}}{\text{Hp-hr}} \right] [0.039] \\ &= \frac{\$9.85}{1000 \text{ lb}} \left[\frac{54.2 \text{ lb}}{\text{Hp-hr}} \right] [0.039] = \frac{\$0.02083}{\text{Hp-hr}} \end{aligned}$$

3.2.6 Process Air Compressor Turbine

The Process Air Compressor Turbine is a special case of a full condensing turbine with a 3000 lb/hr extraction flow at 150 psig. Since the extraction flow is small and at a pressure close to the turbine inlet condition, the turbine steam rate is calculated using the steam flow going to full condensing and the design horsepower rating. The energy charge is calculated as a full condensing turbine, namely:

$$\begin{aligned} \text{Steam Rate} &= \frac{49,000 \text{ lb/hr}}{5112 \text{ Hp}} = 9.6 \frac{\text{lb}}{\text{Hp-hr}} \\ (\text{Energy Charge})_{\text{PACT}} &= \frac{\$9.85}{1000 \text{ lb}} \left[\frac{\text{S.R. } 1\text{b}}{\text{Hp-hr}} \right] \\ &= \frac{\$9.85}{1000 \text{ lb}} \left[\frac{9.6 \text{ lb}}{\text{Hp-hr}} \right] = \frac{\$0.09460}{\text{Hp-hr}} \end{aligned}$$

3.2.7 Refrigeration Compressor Turbine

The Refrigeration Compressor Turbine is a special case of a full condensing turbine with induction flow from the 50 psi Steam System. Both the 450 psi throttle steam and the 50 psi induction steam go to full condensing, therefore, each stream is charged the full cost for steam as its energy level. The steam flows used in this calculation are from the turbine vendor data sheet and are not the same as those appearing on the steam flow diagrams. The charge for 450 psi steam is:

$$\frac{\$9.85}{1000 \text{ lb}} \times \frac{20,300 \text{ lb}}{\text{hr}} = \frac{\$200.00}{\text{hr}}$$

The charge for 50 psi steam (from Section 3.2.4) is:

$$\frac{\$9.14}{1000 \text{ lb}} \times \frac{80,000 \text{ lb}}{\text{hr}} = \frac{\$731.20}{\text{hr}}$$

At a design horsepower rating of 6660 Hp, the total charge rate becomes:

$$(\text{Energy Charge})_{\text{RCT}} = \frac{\$200.00 + \$731.20}{\text{hr} \quad (6660 \text{ Hp})} = \frac{\$0.13984}{\text{Hp-hr}}$$

Using the energy charge and the cost of 450 psi steam, an equivalent steam rate for this turbine then becomes:

$$\text{Equivalent S.R.} = \frac{\$0.13984}{\text{Hp-hr}} \left[\frac{1000 \text{ lb}}{\$9.85} \right] = \frac{14.2 \text{ lb}}{\text{Hp-hr}}$$

3.2.8 Synthesis Gas Compressor Turbine

The Synthesis Gas Compressor Turbine is a special case of a full condensing turbine with extraction flow to the 450 psi Steam System. The extraction steam flow is charged as a backpressure turbine, while the condensing steam flow is charged as a full condensing turbine.

The 1500 psi inlet steam to the Syn Gas Turbine comes from the high pressure steam system, and is generated from a combination of fossil fuel and waste heat. The waste heat is actually a combination of fossil fuel heat from the Primary Reformer and the heat from exothermic reactions in the process. In order to properly charge the energy used in the Syn Gas Turbine, it is necessary to calculate the cost of 1500 psi steam based on the amount of fossil fuel heat used both in the direct fired boiler and as waste heat.

The following Table 3-1 shows the assumptions made for the proportions of waste heat attributable to fossil fuel and exothermic heats of reaction for each source of waste heat recovery.

Table 3-1

	Fossil Fuel	Chemical Reaction
BFW & Condensate Heater (E-409)	100%	0%
BFW Heater (E-709)	0%	100%
BFW Heater (E-106)	100%	0%
Feedwater Economizer (D-104)	100%	0%
Reform Gas W.H. Boiler (E-105)	33%	66%
Converted Gas W.H. Boiler (E-103)	0%	100%

Therefore, using the waste heat loads in Table B-1 of Appendix B the following amounts of waste heat will be included with the fossil fuel in calculating 1500 psi steam costs:

$$\begin{aligned}
 \text{BFW/COND HTR (E-409)} & 1 \times (0.385 \times 10^8 \text{ BTU/HR}) = 0.385 \times 10^8 \text{ BTU/HR} \\
 \text{BFW Heater (E-106)} & 1 \times (0.063 \times 10^8 \text{ BTU/HR}) = 0.063 \times 10^8 \text{ BTU/HR} \\
 \text{FW Econ. (D-104)} & 1 \times (0.433 \times 10^8 \text{ BTU/HR}) = 0.433 \times 10^8 \text{ BTU/HR} \\
 \text{R.G.W.H.B. (E-105)} & 0.33 \times (0.908 \times 10^8 \text{ BTU/HR}) = 0.300 \times 10^8 \text{ BTU/HR} \\
 \text{TOTAL} & = 1.181 \times 10^8 \text{ BTU/HR}
 \end{aligned}$$

Therefore, the fraction of fossil fuel contributing to waste heat, based on the assumption in Table 3-1 is:

$$\begin{aligned}
 \text{Fraction of Fossil Fuel} & = \frac{1.181 \times 10^8}{2.444 \times 10^8} = 0.48 \text{ or } 48\% \\
 \text{Heat in Waste Heat} &
 \end{aligned}$$

The fossil fuel heat attributable to the generation of 1500 psi steam from saturated liquid at the condensing pressure to the Synthesis Gas Turbine inlet condition is now calculated along with the steam cost, taking boiler efficiency into account.

$$\begin{aligned}
 \text{Fossil Fuel Waste Heat} & = 1.18 \times 10^8 \text{ BTU/HR} \\
 \text{PCC Boiler} & = 0.63 \times 10^8 \text{ BTU/HR} \\
 \text{PCC Superheater} & = 0.45 \times 10^8 \text{ BTU/HR} \\
 \text{PCC Superheater} & = 0.25 \times 10^8 \text{ BTU/HR} \\
 \text{TOTAL} & = 2.51 \times 10^8 \text{ BTU/HR}
 \end{aligned}$$

Assuming a boiler efficiency of 76 percent, based on vendor data sheets, the cost of 1500 psi steam becomes:

$$\begin{aligned}
 \text{1500 psi Steam Cost} & = \left[\frac{2.51 \times 10^8 \text{ BTU/HR}}{0.76} \right] \left[\frac{\$5.90}{10^6 \text{ BTU}} \right] \left[\frac{\text{hr}}{325,000 \text{ lb}} \right] \left[\frac{1000}{1000} \right] \\
 & = \underline{\$6.00} \\
 & \quad 1000 \text{ lb}
 \end{aligned}$$

Table 3-2

<u>Turbine</u>	<u>Type</u>	<u>Design Hp</u>	<u>Steam Rate</u> <u>lb/lhp-hr</u>	<u>Energy Charge</u>	
				<u>\$/lhp-hr</u>	<u>\$/hr</u>
1. Syn Gas Comp	*	12,760	4.9	0.0296	377.70
2. Refrig Comp	*	6,660	14.2	0.1398	931.07
3. Air Comp	*	5,112	9.6	0.0946	483.60
4. H.P. BFW PP	BP	1,000	31.3	0.0223	22.30
5. Cooling Water PP	FC	1,880	14.5	0.1429	268.65
6. Nat'l Gas Comp	BP	870	30.5	0.0217	18.88
7. TEA Soln PP	BP	860	31.1	0.0222	19.09
8. Hydr. Supply PP	**	765	54.2	0.0208	15.91
9. I.D. Fan	BP	275	37.4	0.0267	7.34
10.H.P. Blr. Circ. PP	BP	230	37.5	0.0267	6.14
11.Erie II BFW PP	BP	200	41.0	0.0292	5.84
12.Aux. Carbamate PP	BP	200	57.8	0.0412	8.24
13.Turbo-Generator	BP	150	66.5	0.0474	7.11
14.L.P. BFW PP	BP	91	50.3	0.0359	3.27
15.Demin. Water PP	FC	80	33.0	0.3252	26.02
16.Syn Seal Oil PP	FC	62	38.0	0.3745	23.22
17.Syn Lube Oil PP	FC	55	38.0	0.3745	20.60
18.FM Lube Oil PP	FC	29	33.0	0.3252	9.43
19.Refrig L.O. PP	FC	22.5	78.0	0.7686	17.29
20.FM Seal Oil PP	FC	<u>22.5</u>	33.0	0.3252	<u>7.32</u>
TOTAL:		31,324 Hp			2,279.02

FC = Full Condensing

BP = Backpressure

* = Special Case - Full Condensing

** = Special Case - Backpressure

The extraction steam flow is charged as a backpressure turbine, while the condensing steam flow is charged as a full condensing turbine. Therefore, the charge for the extraction steam flow is:

$$\frac{\$6.00}{1000 \text{ lb}} \left[\frac{266,000 \text{ lb}}{\text{hr}} \right] \left[\frac{1316.4 - 1298.6}{1316.4 - 93.34} \right] \frac{\text{BTU/lb}}{\text{BTU/lb}} = \frac{\$23.23}{\text{hr}}$$

The charge for the full condensing steam flow is:

$$\frac{\$6.00}{1000 \text{ lb}} \left[\frac{59,000 \text{ lb}}{\text{hr}} \right] = \frac{\$354.00}{\text{hr}}$$

At a design horsepower of 12,760 Hp, the total charge rate becomes:

$$(\text{Energy Charge})_{\text{SGCT}} = \frac{\$23.23 + \$354.00}{\text{hr (12,760 Hp)}} = \frac{\$0.0296}{\text{Hp-hr}}$$

Using the energy charge and the cost of 1500 psi steam, an equivalent steam rate for this turbine then becomes:

$$\text{Equivalent S.R.} = \frac{\$0.0296}{\text{Hp-hr}} \left[\frac{1000 \text{ lb}}{\$6.00} \right] = 4.93 \frac{\text{lb}}{\text{Hp-hr}}$$

3.2.9 Conclusion.

As a check of the calculation of energy charges attributed to each steam turbine in the VNP Plant, the overall unit cost rate was calculated and compared to the gross unit cost rate using the gross unit efficiency calculated in Appendix B.

$$\begin{aligned} \text{Overall Unit} &= \frac{\sum \left[\frac{\$}{\text{Hp-hr}} \right] [H_F]}{\sum \text{Hp}} = \frac{\$2279.02/\text{hr}}{31,324 \text{ Hp}} = \frac{\$0.073}{\text{Hp-hr}} \\ \text{Cost Rate} & \end{aligned}$$

Now, using the gross unit efficiency of 20 percent, the gross unit cost rate becomes:

$$\begin{array}{rcl} \text{Gross Unit} & = & \frac{\$5.90}{10^6 \text{ BTU}} \left[\frac{2544.4 \text{ BTU}}{\text{Hp-hr}} \right] \left[\frac{1}{0.20} \right] = \frac{\$0.075}{\text{Hp-hr}} \\ \text{Cost Rate} & & \end{array}$$

Therefore, there appears to be good agreement between the approach taken to access energy charges to each steam turbine and the overall plant charge rate based on the calculation of gross rankine cycle thermal efficiency.

3.3 TOTAL CHARGES FOR GEOTHERMAL TURBINES

3.3.1 Introduction

The total cost of operating new geothermal turbines has been calculated to compare with continued operation of existing fossil fuel steam turbines. The total charges were calculated as the sum of the geothermal plant demand charge, the geothermal turbine capital cost charge, and the geothermal turbine energy charge all computed on a cost per horsepower-hour basis for the period 1980 through 1989.

3.3.2 Geothermal Plant Demand Charges

For any comparison of equipment driver options utilizing geothermal energy in place of fossil fuel, it is necessary to calculate the demand charge for building the geothermal plant to supply geothermal energy in a usable form to drive plant equipment. Therefore, geothermal plant demand charges were calculated for both binary and flash steam plants based on the capital cost estimates discussed in Section 2.4. The demand and energy charge for each equipment driver will be added later, therefore the geothermal plant demand charges are calculated for all plant equipment except the turbines. Results of the calculations are shown in Tables 3-3 and 3-4. Because the demand charge varies with the plant size, it is assumed, for these calculations, that the total plant modification is in the range of 20 to 30 MW. Therefore the binary plant demand charge is assumed to be \$670/Hp, while the flash steam plant demand charge is assumed to be \$625/Hp.

Using the fixed charge rate of 17.4 percent calculated in Appendix D to convert capital investment costs

Table 3-3

BINARY PLANT DEMAND CHARGES

(1977 Dollars)

<u>Gross Capacity MW</u>	<u>Total Capital Cost \$ Millions</u>	<u>Installed Turbine Cost \$ Millions</u>	<u>Net Plant Capacity KW</u>	<u>Demand Charge \$/KW</u>	<u>Demand Charge \$/Hp</u>
5	6.20	.74	4,000	1,365	1,018
10	10.53	1.49	8,100	1,116	833
15	14.06	2.22	12,100	979	730
20	18.46	3.40	16,200	930	694
25	21.64	4.14	20,200	866	646
30	27.55	6.04	24,300	885	660

Assuming the geothermal plant will be in the 20 to 30 Gross MW range,
use a demand charge of \$670/Hp.

Table 3-4
FLASH STEAM PLANT DEMAND CHARGE
(1977 Dollars)

<u>Gross Capacity MW</u>	<u>Total Capital Cost \$ Millions</u>	<u>Installed Turbine Cost \$ Millions</u>	<u>Net Plant Capacity KW</u>	<u>Demand Charge \$/KW</u>	<u>Demand Charge \$/Hp</u>
5	9.39	1.76	4,400	1,734	1,294
10	13.61	3.05	8,800	1,200	895
15	18.69	4.80	13,200	1,052	785
20	22.73	6.62	17,600	915	683
25	25.42	8.38	22,000	775	578
30	33.60	11.77	26,400	827	617

Assuming the geothermal plant will be in the 20 to 30 Gross MW range,
use a demand charge of \$625/Hp.

into annual charge rates, the escalation rate of 20.8 percent to convert 1977 costs into 1980 costs, and a plant capacity factor of 75 percent, a unit charge rate for geothermal demand charges is calculated in \$/Hp-hr. Therefore, the unit demand charge rates become:

$$\begin{aligned} \text{Binary Plant Unit} &= \frac{\$670}{\text{Hp}} \times \frac{0.174}{\text{yr}} \times \frac{\text{yr}}{8750 \text{ hr}} \times \frac{1}{0.75} \\ \text{Demand Charge Rate} & \times (1.208) = \frac{\$0.0214}{\text{Hp-hr}} \end{aligned}$$

$$\begin{aligned} \text{Flash Plant Unit} &= \frac{\$625}{\text{Hp}} \times \frac{0.174}{\text{yr}} \times \frac{\text{hr}}{8760 \text{ hr}} \times \frac{1}{0.75} \\ \text{Demand Charge Rate} & \times (1.208) = \frac{\$0.0199}{\text{Hp-hr}} \end{aligned}$$

3.3.3 Energy Charges for Geothermal Turbines

3.3.3.1 Binary Plant Vapor Expanders

Energy charges for operating new radial inflow isobutane vapor expanders were calculated based on converting the isobutane flow rates quoted by the expander vendors to equivalent brine flow rates and charging the expander for the full cost of that equivalent single-phase brine flow. To calculate an equivalent brine flow rate, a heat balance equation was written relating isobutane flow rate to brine flow rate, namely:

$$Q_{\text{ISO}}(\Delta H) = Q_{\text{WAT}}C_p(\Delta T)$$

where:

- Q_{ISO} = Isobutane flow rate
- ΔH = Heat added to the isobutane
- Q_{WAT} = Brine flow rate
- C_p = Brine specific heat
- ΔT = Temperature drop in the brine

Therefore,

$$\frac{Q_{\text{WAT}}}{Q_{\text{ISO}}} = \frac{(\Delta H)}{C_p (\Delta T)} = \frac{162.6}{1 (199.3)} = 0.816$$

For our calculations we will use a value for the ratio of brine flow to isobutane flow of 0.816. Therefore, with this ratio, the rated horsepower, the isobutane flow rate quoted by the vendor, and the levelized single-phase brine cost of \$1.50/10⁶ BTU from Table C-1 of Appendix C, the vapor expander energy charge was calculated in \$/Hp-hr by the following equation:

$$\frac{\$}{\text{Hp-hr}} = \left[\frac{\text{Isobutane Flow, lb/hr}}{\text{Rated Hp}} \right] \times \left[\frac{0.816 \text{ lb brine}}{\text{lb isobutane}} \right] \times \left[\frac{\$1.50}{10^6 \text{ BTU}} \right] \times \left[\frac{205 \text{ BTU}}{\text{lb}} \right]$$

3.3.3.2

Flash Plant Steam Turbines

The three brine flashing pressures for the flash steam cycle plant were determined by calculations appearing in Appendix E. Therefore, the energy charges for operating new saturated flash steam turbines were calculated based on steam costs found by proportioning the cost of two-phase brine between the three flash stages as a function of the total BTU's extracted from each stage. Assuming 1000 pounds of brine entering the first flash stage of the three stage cascading flash system, the three flash stages will generate the following amounts of steam: 48 pounds of 65 psia steam, 44 pounds of 33 psia steam, and 37 pounds of 16 psia steam. The brine rejected from the final stage will therefore be at the saturation temperature corresponding to 16 psia, namely 216°F.

Energy charges were based on the levelized cost for two-phase brine of \$1.25/10⁶ BTU from Table C-1 of Appendix C for the period 1980 through 1989. Therefore, levelized steam costs are calculated for each flash steam pressure and are \$1.37 per 1000 pounds of 65 psia steam, \$1.35 per 1000 pounds of 33 psia steam, and \$1.33 per 1000 pounds of 16 psia steam.

The energy charge in \$/Hp-hr for each full condensing saturated steam turbine is calculated in an identical manner to the calculation of energy charges for the existing full condensing steam turbines operating on fossil fuel, by multiplying the actual turbine steam rate by the cost per 1000 pounds of the throttle steam at its inlet pressure. Therefore,

$$\frac{\$}{\text{Hp-hr}} = \left[\frac{\$}{1000 \text{ lb}} \right] \times \left[\frac{\text{S.R., lb}}{\text{Hp-hr}} \right]$$

Induction steam turbine energy charges were calculated using the steam flows to each turbine inlet to determine total \$/hr steam costs and dividing by the rated Hp to give \$/Hp-hr energy charges.

3.3.4 Conclusions

3.3.4.1 Binary Plant Vapor Expanders

The total charges for binary vapor expanders in \$/Hp-hr were calculated as the sum of the geothermal plant demand charge, binary vapor expander installed capital cost charge, and the brine energy charge all in \$/Hp-hr. The geothermal plant demand charge is calculated in Section 3.3.2. The brine energy charge equation is given in Section 3.3.3.1. The binary vapor expander installed capital cost was calculated based on budget quotations submitted by three vapor expander manufacturers: Rotoflow, Mafi-Trench, and Lotema. Capital cost charges for vapor expanders were calculated using the fixed charge rate of 17.4 percent (calculated in Appendix D), factors for inflation and installation costs, and a capacity factor of 75 percent. Total charges in \$/Hp-hr were calculated for each vapor expander proposed and the lowest total charge was selected for each expander application. A summary of the calculations of the lowest total charges for each vapor expander is shown in Table 3-6. Item 21 in Table 3-6 is for an 8 MW turbogenerator set to provide the present plant electrical demand and will be used later in this study to determine on-site power generation costs from a geothermal binary plant.

3.3.4.2 Flash Plant Steam Turbines

The total charges for flash plant steam turbines in \$/Hp-hr were calculated as the sum of the geothermal plant demand charge, flash steam turbine installed capital cost charge, and the brine energy charge, all in \$/Hp-hr. The geothermal plant demand charge is calculated in Section 3.3.2. The brine energy charge equation is given in Section 3.3.3.2. The flash steam turbine installed capital cost was calculated based on budget quotations submitted by three steam turbine manufacturers: Elliott, Turbodyne, and Terry. Capital cost charges for steam turbines were calculated using the fixed charge rate of 17.4 percent (calculated in Appendix D), factors for inflation and installation costs, and a capacity factor of 75 percent.

TABLE 3-6

GEOTHERMAL BINARY EXPANDERS
LEVELIZED CHARGES FOR PERIOD 1980 TO 1989
\$/Hp-hr

Replace Existing Turbines	NORMAL HP	RATED HP	DESIGN RPM	ISOBUTANE FLOW (lb/hr)	TURBINE COST \$(1977)	TURBINE INSTALLED COST \$(1977)	CAPITAL COST \$/Hp-hr (1980)	DEMAND CHARGE \$/Hp-hr (1980)	EXPANSION EFFICIENCY %	ENERGY CHARGE \$/Hp-hr (1980)	TOTAL CHARGES \$/Hp-hr (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	703,000	200,000	230,000	.0005	.0214	83	.0126	.0345
2. REFRIG COMPRESSOR	6,600	7,325	8,550	682,700	350,000	402,500	.0018	.0214	84	.0234	.0466
3. AIR COMPRESSOR	5,112	5,625	3,625	525,157	300,000	345,000	.0020	.0214	84	.0234	.0468
4. H.P. BFW PUMP	1,000	1,320	3,570	112,000	130,000	149,500	.0036	.0214	83	.0213	.0463
5. COOLING WATER PUMP	940	980	5,280	104,730	120,000	138,000	.0045	.0214	81	.0268	.0527
6. NATURAL GAS COMPRESSOR	870	960	8,535	97,400	110,000	126,500	.0042	.0214	81	.0255	.0511
7. T.E.A. SOL'N PUMP	860	960	3,570	96,354	110,000	126,500	.0042	.0214	81	.0252	.0508
8. HYDRAULIC SUPPLY PUMP	765	840	4,500	83,790	110,000	126,500	.0048	.0214	81	.0250	.0512
9. I.D. FAN	275	275	4,496	34,610	80,000	92,000	.0107	.0214	76	.0316	.0637
10. H.P. BOILER CIRC. PUMP	230	248	4,500	29,600	80,000	92,000	.0119	.0214	76	.0299	.0632
11. ERIE 2 BFW PUMP	200	250	3,550	26,500	70,000	80,500	.0103	.0214	75	.0266	.0583
12. AUX. CARBAMATE PUMP	200	250	2,000	26,500	70,000	80,500	.0103	.0214	75	.0266	.0583
13. TURBO-GENERATOR	150	186	1,800	19,000	130,000	149,500	.0257	.0214	75	.0256	.0727
14. L.P. BFW PUMP	91	95	3,550	14,545	55,000	63,250	.0213	.0214	68	.0384	.0811
15. DEMIN. WATER PUMP	80	80	3,550	13,725	55,000	63,250	.0253	.0214	68	.0430	.0897
16. SYN SEAL OIL PUMP	62	80	3,550	11,480	55,000	62,250	.0253	.0214	68	.0360	.0827
17. SYN LUBE OIL PUMP	55	80	3,550	10,925	55,000	63,250	.0253	.0214	66	.0343	.0810
18. FM LUBE OIL PUMP	29	40	3,550	7,715	55,000	63,250	.0506	.0214	55	.0484	.1204
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	6,885	55,000	63,250	.0675	.0214	53	.0576	.1465
20. FM SEAL OIL PUMP	22.5	22.5	3,550	6,885	55,000	63,250	.0899	.0214	53	.0768	.1881
<u>Add Additional Turbine</u>											
21. TURBO-GENERATOR	10,725	12,000	3,600	1,224,539	500,000*	575,000	.0015	.0214	84	.0256	.0485

*INCLUDES GENERATOR

Total charges in \$/Hp-hr were calculated for each steam turbine proposed and the lowest total charge was selected for each turbine application. A summary of the calculations of the lowest total charges for each steam turbine is shown in Table 3-7. Item 21 in Table 3-7 is for an 8 MW turbo-generator set to provide the present plant electrical demand and will be used later in this study to determine on-site power generation costs from a geothermal flash steam plant.

3.4 TOTAL CHARGES FOR ELECTRIC MOTORS

3.4.1 Introduction

The total cost of operating existing and new electric motors has been calculated to compare with operation of turbine powered equipment drivers, both geothermal and fossil fuel powered. Existing electric motor operating costs were based on energy charges for each source of electrical power from both off-site and on-site generation. New electric motor total operating costs were based on the sum of the capital cost charges for new electric motors and the electric energy charges from each power source considered. All charges were computed on a cost per horsepower-hour basis for the period 1980 through 1989.

3.4.2 Capital Cost Charges for New Electric Motors

New electric motors were considered as alternative drivers for plant equipment, with electrical power supplied from both on-site and off-site sources, where on-site electrical power includes both fossil and geothermal sources of energy. Therefore, it was necessary to determine the cost of installing new electric motors for plant equipment drivers. Installed capital costs were estimated based on all work being performed by an outside electrical contractor, with associated labor costs, indirect costs, and profit included.

Prices for electric motors, motor controls, and required gearing for capacities in excess of 250 Hp were based on budget prices received from a major motor manufacturer. Vendor quotations included prices for NEMA type 1 motor starters and circuit breakers. Feeder material and installation costs were based on 500 lineal feet conductor pull-through for each motor. Space heater, instrumentation, and emergency shut-down wiring and installation was not included. Differentiation of conductor and conduit size was considered, however their effect on the total installation cost was determined to be of little significance. The total capital costs for materials and installation are summarized for each motor size in Table 3-8.

TABLE 3-7

GEOHERMAL FLASHED STEAM TURBINES LEVELIZED CHARGES FOR PERIOD 1980 TO 1989 \$/Hp-hr												
<u>Replace Existing Turbines</u>	NORMAL HP	RATED HP	DESIGN RPM	THROTTLE PRESS. PSIA	INDUCTION PRESS. PSIA	TURBINE COST \$(1977)	TURBINE INSTALLED COST \$(1977)	CAPITAL COST \$/Hp-hr (1980)	DEMAND CHARGE \$/Hp-hr (1980)	STEAM RATE lb/Hp-hr	ENERGY CHARGE \$/Hp-hr (1980)	TOTAL CHARGES \$/Hp-hr (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	33	16	950,000	1,016,500	.0023	.0199	21.4	.0287	.0509
2. REFRIG COMPRESSOR	6,600	7,325	8,550	33	16	800,000	856,000	.0037	.0199	21.84	.0293	.0529
3. AIR COMPRESSOR	5,112	5,625	3,625	33	16	750,000	802,500	.0046	.0199	21.15	.0284	.0529
4. H.P. BFW PUMP	1,000	1,320	3,570	33	--	165,000	176,550	.004	.0199	27.0	.0365	.0604
5. COOLING WATER PUMP	940	980	5,280	33	--	200,000	214,000	.0068	.0199	20.3	.0274	.0541
6. NATURAL GAS COMPRESSOR	870	960	8,585	33	--	315,000	337,050	.0112	.0199	25.0	.03375	.0649
7. T.E.A. SOL'N PUMP	860	960	3,570	33	--	165,000	176,550	.006	.0199	27.0	.0365	.0624
8. HYDRAULIC SUPPLY PUMP	765	840	4,500	33	--	260,000	278,200	.0106	.0199	22.6	.0305	.0610
9. I.D. FAN	275	275	4,496	33	--	40,000	42,800	.0016	.0199	23.0	.031	.0525
10. H.P. BOILER CIRC. PUMP	230	248	4,500	33	--	40,000	42,800	.0055	.0199	23.0	.031	.0564
11. ERIE 2 BFW PUMP	200	250	3,550	33	--	40,000	42,800	.0055	.0199	24.6	.0332	.0586
12. AUX. CARBAMATE PUMP	200	250	2,000	33	--	45,000	48,150	.0062	.0199	31.0	.04185	.0680
13. TURBO-GENERATOR	150	186	1,800	33	--	55,000	58,850	.010	.0199	31.0	.04185	.0718
14. L.P. BFW PUMP	91	95	3,550	33	--	40,000	42,800	.0144	.0199	24.6	.0332	.0675
15. DEMIN. WATER PUMP	80	80	3,550	33	--	40,000	42,800	.0171	.0199	24.6	.0332	.0702
16. SYN SEAL OIL PUMP	62	80	3,550	33	--	40,000	42,800	.0171	.0199	24.6	.0332	.0702
17. SYN LUBE OIL PUMP	55	80	3,550	33	--	40,000	42,800	.0171	.0199	24.6	.0332	.0702
18. FM LUBE OIL PUMP	29	40	3,550	33	--	40,000	42,800	.0342	.0199	30.0	.0405	.0946
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	33	--	40,000	42,800	.0514	.0199	30.0	.0405	.1118
20. FM SEAL OIL PUMP	22.5	22.5	3,550	33	--	40,000	42,800	.0608	.0199	30.0	.0405	.1212
<u>Add Additional Turbine</u>												
21. TURBO-GENERATOR	10,725	----	3,600	33	16	1,250,000	1,337,500*	.004	.0199	22.3	.030	.0539

*INCLUDES GENERATOR

TABLE 3-8

NEW ELECTRIC MOTOR DEMAND CHARGES \$/Hp-hr	NORMAL H.P.	RATED H.P.	SPEED RPM	MATERIAL COSTS \$(1977)	CONTRACT LABOR COSTS \$(1977)	CONTRACT INDIRECT COSTS \$(1977)	CONTRACT PROFIT \$(1977)	CAPITAL COST \$(1977)	DEMAND CHARGE \$/Hp-hr (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	795,635	156,908	81,782	103,324	1,137,757	.0026
2. REFRIG COMPRESSOR	6,660	8,000	8,550	489,622	96,558	50,328	63,651	700,159	.0028
3. AIR COMPRESSOR	5,112	5,500	3,625	324,593	64,013	33,365	42,197	464,168	.0027
4. H.P. BFW PUMP	1,000	1,500	3,570	154,053	27,619	14,395	19,606	215,673	.0046
5. COOLING WATER PUMP	940	1,000	5,280	114,915	17,855	9,306	14,208	156,284	.0050
6. NATURAL GAS COMPRESSOR	870	1,000	8,585	104,950	16,934	8,826	13,071	143,781	.0046
7. T.E.A. SOL'N PUMP	860	1,000	3,570	111,795	18,039	9,402	13,924	153,160	.0049
8. HYDRAULIC SUPPLY PUMP	765	900	4,500	108,830	17,560	9,152	13,554	149,096	.0053
9. I.D. FAN	275	300	4,496	46,196	7,177	3,740	5,711	62,824	.0067
10. H.P. BOILER CIRC. PUMP	230	250	4,500	44,817	6,963	3,629	5,541	60,950	.0078

NOTES: 1. ALL MOTORS ARE WEATHER PROTECTED, TYPE 2, 1800 RPM: 4,000 VOLT/3 PH/60 HERTZ: SERVICE FACTOR 1.0
 2. MOTOR PRICES INCLUDE COST OF INSTALLED GEARING.
 3. STARTER AND SWITCHGEAR BREAKER ENCLOSERS ARE NEMA 1.
 4. ASSUME \$6.88 PER MANHOUR FOR CONTRACTORS INDIRECT COSTS.
 5. ASSUME 10% PROFIT FOR CONTRACTOR.
 6. ASSUME LABOR COST AT \$13.20 PER MANHOUR.

Prices for synchronous electric motors and motor controls for capacities between 20 Hp and 250 Hp were taken directly from industrial cost estimating standards. Electric motors, motor starters, and circuit breakers were assumed to be explosion proof. Feeder material and installation costs were based on 500 lineal feet conductor pull-through for each motor. Space heater, instrumentation, and emergency shut-down wiring and installation was not included. Differentiation of conductor and conduit size was considered, however their effect on the total installation cost was determined to be of little significance. The total capital costs for materials and installation are summarized for each motor size in Table 3-9.

The demand charge for each electric motor was calculated from the total capital cost by means of the fixed charge rate, rated horsepower, capacity factor, and escalation rate. Motor demand charges for each motor size also appear in Tables 3-8 and 3-9.

3.4.3 Energy Charges for Electric Motors

3.4.3.1 Introduction

Total charges were calculated for operating existing VNP Plant electrical motors and proposed new electrical motors on off-site and on-site electrical power from both fossil and geothermal sources of energy. Off-site power was charged at the levelized cost for the period 1980 through 1989, calculated in Appendix C. On-site fossil fuel electrical power costs include the cost of providing a turbine-generator set that operates off of the existing VNP Plant steam system. On-site geothermal electrical power costs include the cost of providing a complete geothermal power plant. A conversion efficiency for electrical power from bus-bar kilowatt-hours to shaft horsepower-hours of 74 percent was assumed, which is equivalent to 1 KW/Hp.

3.4.3.2 Off-site Electrical Power

The levelized off-site electrical power cost for the period 1980 through 1989, calculated in Appendix C, is \$10.53/10⁶ BTU. Using the ideal conversion ratio between BTU's and Hp-hr's and the assumed electrical conversion efficiency of 74 percent, the energy charge rate for electric motors operating on off-site electrical power becomes:

TABLE 3-9

NEW ELECTRIC MOTOR DEMAND CHARGES \$/Hp-hr	NORMAL H.P.	RATED H.P.	SPEED RPM	MATERIAL COSTS \$(1977)	CONTRACT LABOR COSTS \$(1977)	CONTRACT INDIRECT COSTS \$(1977)	CONTRACT PROFIT \$(1977)	CAPITAL COST \$(1977)	DEMAND CHARGE \$/Hp-hr (1980)
11. ERIE 2 BFW PUMP	200	250	3,550	21,552	5,955	3,104	3,061	33,672	.0043
12. AUX. CARBAMATE PUMP	200	250	2,000	20,052	5,955	3,104	2,911	32,022	.0041
13. TURBO-GENERATOR	150	186	1,800	-----	-----	-----	-----	-----	-----
14. L.P. BFW PUMP	91	95	3,550	10,087	3,883	2,024	1,599	17,593	.0056
15. DEMIN. WATER PUMP	80	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
16. SYN SEAL OIL PUMP	62	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
17. SYN LUBE OIL PUMP	55	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
18. FM LUBE OIL PUMP	29	40	3,550	3,967	1,938	1,010	691	7,606	.0061
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	3,564	1,911	996	647	7,118	.0076
20. FM SEAL OIL PUMP	22.5	22.5	3,550	2,580	1,536	800	492	5,408	.0069

NOTES: 1. ALL MOTORS ARE EXPLOSION PROOF, CLASS 1, GROUP D, 480 V/3PH/60 HERTZ.
 2. STARTERS AND CIRCUIT BREAKERS ARE EXPLOSION PROOF.
 3. ASSUME \$6.88 PER MANHOUR FOR CONTRACTORS INDIRECT COSTS.
 4. ASSUME 10% PROFIT FOR CONTRACTOR.
 5. ASSUME LABOR COST AT \$13.20 PER MANHOUR.

$$(\text{Energy Charge})_{\text{OFFSITE}} = \frac{\$10.53}{10^6 \text{ BTU}} \times \frac{2544.4 \text{ BTU}}{\text{Hp-hr}} \times \frac{1}{0.74} = \frac{\$.0362}{\text{Hp-hr}}$$

This figure constitutes the total charge for operating existing motors on off-site electrical power. The total charge for operating new electrical motors on off-site electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.3 On-Site Fossil Fuel Power

The total charge for generating on-site fossil fuel electrical power at the VNP plant was based on using 450 psig extraction steam from the Synthesis Gas Compressor Turbine Drive and providing a 25 MW turbine-generator set. A budget quotation was received from a leading turbine manufacturer, satisfying the above conditions:

Table 3-10

25 MW Turbine-Generator Set
 Inlet Conditions: 465 psia, 595° F
 Exhaust Conditions: 4" HgA
 Speed: 3600 r.p.m.
 Actual Steam Rate: 8.65 lb/Hp-hr
 Turbine Cost: \$1,030,000
 Generator Cost: \$1,000,000

Assuming the total installed cost for a 25 MW Turbine-generator is twice the equipment cost, the capital charge rate is calculated using the fixed charge rate, escalation rate, and plant capacity factor:

$$25,000 \text{ KW} \times \frac{\text{Hp}}{0.746 \text{ KW}} = 33,512 \text{ Hp}$$

$$\left[\begin{array}{l} \text{Capital} \\ \text{Charge} \\ \text{Rate} \end{array} \right] = (\$4,060,000)(1.208)(0.174) \left[\frac{1}{33,512 \text{ Hp}} \right] \left[\frac{\text{YR}}{8760 \text{ hr}} \right] \left[\frac{1}{0.75} \right]$$

$$= \$0.0039/\text{Hp-hr}$$

The energy charge for operating the full condensing turbine was calculated by multiplying the actual turbine steam rate with the cost charge for 450 psi extraction

steam. From previous calculations in Section 3.2.8, the cost for 1500 psi steam to the Syn Gas Turbine is \$1950/hr. The energy charge for the Syn Gas Turbine is \$377.23/hr. Therefore, the cost for the 266,000 lb/hr extraction steam from the Syn Gas Turbine is:

$$\begin{aligned} \text{Extraction Steam} &= \frac{\$1950}{\text{hr}} - \frac{\$377.23}{\text{hr}} = \frac{\$1572.77}{\text{hr}} \\ \text{Cost} &= \frac{\$1572.77}{\text{hr}} \times \frac{\text{hr}}{266,000 \text{ lb}} \times \frac{1000}{1000} = \frac{\$5.90}{1000 \text{ lb}} \end{aligned}$$

Therefore, the energy charge for the 25 MW Turbine-Generator is:

$$\left[\begin{array}{l} \text{Energy Charge} \\ \text{25 MW T.G.} \end{array} \right] = \frac{\$5.90}{1000 \text{ lb}} \left[\begin{array}{l} 8.65 \text{ lb} \\ \text{Hp-hr} \end{array} \right] = \frac{\$0.0510}{\text{Hp-hr}}$$

Assuming a 74 percent conversion efficiency from the bus-bar electrical power to the electric motor shaft horsepower, the total charge for on-site fossil fuel power generation is the sum of the Capital Charge Rate and the converted Energy Charge Rate:

$$\left[\begin{array}{l} \text{Total Energy} \\ \text{Charge} \end{array} \right]_{\text{ON-SITE FOSSIL}} = \frac{\$.0039}{\text{Hp-hr}} + \frac{\$.051}{(0.74) \text{ Hp-hr}} = \frac{\$.0728}{\text{Hp-hr}}$$

This figure constitutes the total charge for operating existing motors on on-site fossil fuel electrical power. The total charge for operating new electric motors with on-site fossil fuel electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.4

On-site Geothermal Binary Cycle Power

The total charge for generating on-site power utilizing a geothermal binary cycle was calculated using the Turbine Capital Cost Charge, Geothermal Plant Demand Charge, and the Turbine Energy Charge listed in

Table 3-6 as Item 21, "Additional Turbo-Generator". Energy charges were converted assuming a 74 percent conversion efficiency from the bus-bar electrical power to the electric motor shaft horsepower. Therefore, the total charge for on-site geothermal binary cycle electrical power is:

$$\begin{aligned} \left[\begin{array}{c} \text{Total Energy} \\ \text{Charge} \end{array} \right] \text{ ONSITE BINARY} &= \left[\begin{array}{c} .0015 \\ + \\ .0214 \\ + \\ \frac{.0256}{0.74} \end{array} \right] \frac{\$}{\text{Hp-hr}} \\ &= \frac{\$.0575}{\text{Hp-hr}} \end{aligned}$$

The total charge for operating new electric motors with on-site geothermal binary cycle electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.5

On-site Geothermal Flash Cycle Power

The total charge for generating on-site power utilizing a geothermal flash steam cycle was calculated using the Turbine Capital Cost Charge, Geothermal Plant Demand Charge, and the Turbine Energy Charge listed in Table 3-7 as Item 21, "Additional Turbo-Generator". Energy charges were converted assuming a 74 percent conversion efficiency from the bus-bar electrical power to the electric motor shaft horsepower. Therefore, the total charge for on-site geothermal flash steam cycle electrical power is:

$$\begin{aligned} \left[\begin{array}{c} \text{Total Energy} \\ \text{Charge} \end{array} \right] \text{ ONSITE FLASH} &= \left[\begin{array}{c} .0040 \\ + \\ .01699 \\ + \\ \frac{.0300}{0.74} \end{array} \right] \frac{\$}{\text{Hp-hr}} \\ &= \frac{\$.0644}{\text{Hp-hr}} \end{aligned}$$

The total charge for operating new electric motors with on-site geothermal flash steam cycle electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Table 3-8 and 3-9.

3.5 SUMMARY

Levelized costs for operating each of twenty turbine driven pumps and compressors with fossil, geothermal, and

off-site electrical energy are summarized in Table 3-11. Costs are in \$/Hp-hr units, which minimizes the effect of capital cost estimates and reflects more heavily the cost of energy for equipment operation. These are relative costs for comparison and are not meant to represent total plant operating costs. Columns 1 through 5 deal with operating existing steam turbines on fossil fuel and operating existing back-up electric motors on both off-site power, and on-site fossil and geothermal energy. The "not applicable" symbol (NA) is used in columns 2 through 5 where there is no existing back-up electric motor. Columns 6 and 7 deal with operating new binary vapor expanders and flash steam turbines using geothermal energy in both cases. Columns 8 through 11 deal with operating new electric motors on both off-site power, and on-site fossil and geothermal energy. The "not applicable" symbol (NA) is used in columns 8 through 11 where back-up electric motors already exist, except for the Cooling Water Pump and Demin Water Pump which have half-capacity back-up electric motors and would require additional motor capacity.

The three lowest cost alternatives for each equipment driver are ranked in Table 3-11 from lowest to highest. Several trends appear from this ranking process, however, care must be taken in drawing conclusions from this method of analysis:

1. Existing backpressure steam turbines are much more economical than the full condensing steam turbines. This is not to say that running existing backpressure turbines should be chosen over all other alternatives, but merely if a choice arose between keeping a full condensing or a backpressure turbine, the backpressure turbine should be maintained.
2. Operating a combination of existing and new electric motors on off-site electrical power would be a cost effective alternative. This assumes that the local utility can supply the additional electrical demand and that the present declining block rate structure will remain unchanged.
3. The binary cycle process appears to be favored over the flash cycle process as an alternative to more conventional energy sources.

Table 3-11 weighs the cost of each alternative on an equal basis, regardless of equipment size. However, to arrive at the best alternative plant arrangement, it will be necessary to weigh the cost of each alternative taking

TABLE 3-11

LEVELIZED COSTS FOR PERIOD 1980-1989 \$/Hp-hr		EXISTING TURBINES (FOSSIL)	EXISTING MOTORS OFFSITE POWER	EXISTING MOTORS ONSITE POWER (FOSSIL)	EXISTING MOTORS ONSITE POWER (BINARY)	EXISTING MOTORS ONSITE POWER (FLASH)	BINARY TURBINE	FLASH TURBINE	NEW MOTORS OFFSITE POWER	NEW MOTORS ONSITE POWER (FOSSIL)	NEW MOTORS ONSITE POWER (BINARY)	NEW MOTORS ONSITE POWER (FLASH)
<u>TURBINES</u>	RATED Hp											
1. SYN. GAS COMPRESSOR	14,000	.0296 ¹	NA	NA	NA	NA	.0345 ²	.0509	.0388 ³	.0754	.0601	.0670
2. REFRIG COMPRESSOR	7,325	.1398	NA	NA	NA	NA	.0466 ²	.0529 ³	.0390 ¹	.0756	.0603	.0672
3. AIR COMPRESSOR	5,625	.0946	NA	NA	NA	NA	.0468 ²	.0529 ³	.0380 ¹	.0746	.0593	.0662
4. H.P. BFW PUMP	1,320	.0223 ¹	.0362 ²	.0728	.0575	.0644	.0463 ³	.0604	NA	NA	NA	NA
5. COOLING WATER PUMP	980	.1429	.0362 ¹	.0728	.0575	.0644	.0527 ³	.0541	.0396 ²	.0762	.0609	.0678
6. NATURAL GAS COMPRESSOR	960	.0217 ¹	NA	NA	NA	NA	.0511 ³	.0649	.0396 ²	.0762	.0609	.0678
7. T.E.A. SOL'N PUMP	960	.0222 ¹	.0362 ²	.0728	.0575	.0644	.0508 ³	.0624	NA	NA	NA	NA
8. HYDRAULIC SUPPLY PUMP	840	.0208 ¹	NA	NA	NA	NA	.0512 ³	.0610	.0400 ²	.0766	.0613	.0682
9. I.D. FAN	275	.0267 ¹	NA	NA	NA	NA	.0637	.0525 ³	.0398 ²	.0764	.0611	.0680
10. H.P. BOILER CIRC. PUMP	248	.0267 ¹	.0362 ²	.0728	.0575	.0644	.0632	.0564 ³	NA	NA	NA	NA
11. ERIE 2 BFW PUMP	250	.0292 ¹	.0362 ²	.0728	.0575	.0644	.0583	.0586	NA	NA	NA	NA
12. AUX CARBAMATE PUMP	250	.0412 ²	NA	NA	NA	NA	.0583 ³	.0680	.0403 ¹	.0769	.0616	.0685
13. TURBO-GENERATOR	186	.0474 ¹	NA	NA	NA	NA	.0727 ³	.0718 ²	NA	NA	NA	NA
14. L.P. BFW PUMP	95	.0359 ¹	.0362 ²	.0728	.0575 ³	.0644	.0811	.0675	NA	NA	NA	NA
15. DEMIN. WATER PUMP	80	.3252	.0362 ¹	.0728	.0575 ³	.0644	.0897	.0702	.0418 ²	.0784	.0631	.0700
16. SYN SEAL OIL PUMP	80	.3745	.0362 ¹	.0728	.0575 ²	.0644 ³	.0827	.0702	NA	NA	NA	NA
17. SYN LUBE OIL PUMP	80	.3745	.0362 ¹	.0728	.0575 ²	.0644 ³	.0810	.0702	NA	NA	NA	NA
18. FM LUBE OIL PUMP	40	.3252	.0362 ¹	.0728	.0575 ²	.0644 ³	.1204	.0946	NA	NA	NA	NA
19. REFRIG LUBE OIL PUMP	30	.7686	.0362 ¹	.0728	.0575 ²	.0644 ³	.1465	.1118	NA	NA	NA	NA
20. FM SEAL OIL PUMP	22.5	.3252	.0362 ¹	.0728	.0575 ²	.0644 ³	.1881	.1212	NA	NA	NA	NA

equipment size into consideration, because the potential energy cost savings are much greater from the larger equipment than from the smaller equipment. Therefore, in Table 3-12 the costs from Table 3-11 have been multiplied by the rated horsepower for each equipment driver to give costs in units of \$/hr. These are relative costs and are not meant to represent total plant operating costs, however these costs will allow the comparison of various alternatives by adding the \$/hr cost for each piece of equipment and determining a relative total plant operating cost.

From Table 3-12 it can be seen that the major portion of potential cost savings will come from changes to the three largest turbines in the plant, which represent about 80 percent of the total fossil fuel turbine costs. It can be assumed, for the present, that large blocks of "inexpensive" offsite electrical power will not be made available to the VNP Plant, in the near term, for operating large electrical motors. Therefore, the optimum solution to reducing fossil fuel energy costs in the VNP Plant steam cycle appears to be:

1. Minimize operating costs for the three largest turbines;
2. Maintain maximum waste heat utilization; and
3. Maintain a balanced steam cycle using a combination of backpressure turbines and electric motors.

This solution can be verified by a comparison of alternatives utilizing the \$/hr costs from Table 3-12. The alternative cost comparisons are listed in Table 3-13, where the "% Reduction" shows the operating cost savings over running the existing turbines on fuel oil.

3.6 CONCLUSIONS OF THE ENERGY UTILIZATION EVALUATION

From Table 3-13, it appears that an optimal solution for reducing fossil fuel costs in the VNP Plant will come by integrating a geothermal binary cycle into the existing plant steam cycle. The Syn Gas Turbine would be maintained and every attempt would be made to run the turbine on steam generated from waste heat exclusively. The extraction steam from the Syn Gas Turbine would be used primarily for process steam requirements with any remaining steam going to back-pressure turbines and intermediate pressure steam requirements.

TABLE 3-12

LEVELIZED COSTS FOR
PERIOD 1980-1989
\$/HR

		EXISTING TURBINES (FOSSIL)	EXISTING MOTORS OFFSITE POWER	EXISTING MOTORS ONSITE POWER (FOSSIL)	EXISTING MOTORS ONSITE POWER (BINARY)	EXISTING MOTORS ONSITE POWER (FLASH)	BINARY TURBINES	FLASH TURBINES	NEW MOTORS OFFSITE POWER	NEW MOTORS ONSITE POWER (FOSSIL)	NEW MOTORS ONSITE POWER (BINARY)	NEW MOTORS ONSITE POWER (FLASH)
	<u>TURBINES</u>	RATED Hp										
1.	SYN GAS COMPRESSOR	14,000	414.4 ¹	NA	NA	NA	483.0 ²	712.6	543.2 ³	1055.6	841.4	938.0
2.	REFRIG COMPRESSOR	7,325	1024.0	NA	NA	NA	341.3 ²	387.5 ³	285.7 ¹	553.8	441.7	492.2
3.	AIR COMPRESSOR	5,625	532.1	NA	NA	NA	263.3 ²	297.6 ³	213.8 ¹	419.6	333.6	372.4
4.	H.P. BFW PUMP	1,320	29.4 ¹	47.8 ²	96.1	75.9	61.1 ³	79.7	NA	NA	NA	NA
5.	COOLING WATER PUMP	980	140.0	35.5 ¹	71.3	56.4	51.6 ³	53.0	38.8 ²	74.7	59.7	66.4
6.	NATURAL GAS COMPRESSOR	960	20.8 ¹	NA	NA	NA	49.1 ³	62.3	38.0 ²	73.2	58.5	65.1
7.	T.E.A. SOL'N PUMP	960	21.3 ¹	34.8 ²	69.9	55.2	48.8 ³	59.9	NA	NA	NA	NA
8.	HYDRAULIC SUPPLY PUMP	840	17.5 ¹	NA	NA	NA	43.0 ³	51.2	33.6 ²	64.3	51.5	57.3
9.	I.D. FAN	275	7.3 ¹	NA	NA	NA	17.5	14.4 ³	10.9 ²	21.0	16.8	18.7
10.	H.P. BOILER CIRC. PUMP	248	6.6 ¹	9.0 ²	18.1	14.3	15.7	14.0 ³	NA	NA	NA	NA
11.	ERIE 2 BFW PUMP	250	7.3 ¹	9.1 ²	18.2	14.4 ³	14.6	14.7	NA	NA	NA	NA
12.	AUX. CARBAMATE PUMP	250	10.3 ²	NA	NA	NA	14.6 ³	17.0	10.1 ¹	19.2	15.4	17.1
13.	TURBO-GENERATOR	186	8.8 ¹	NA	NA	NA	13.5 ³	13.4 ²	NA	NA	NA	NA
14.	L.P. BFW PUMP	95	3.4 ¹	3.4 ²	6.9	5.5 ³	7.7	6.4	NA	NA	NA	NA
15.	DEMIN. WATER PUMP	80	26.0	2.9 ¹	5.8	4.6 ³	7.2	5.6	3.3 ²	6.3	5.0	5.6
16.	SYN SEAL OIL PUMP	80	30.0	2.9 ¹	5.8	4.6 ²	6.6	5.6	NA	NA	NA	NA
17.	SYN LUBE OIL PUMP	80	30.0	2.9 ¹	5.8	4.6 ²	6.5	5.6	NA	NA	NA	NA
18.	FM LUBE OIL PUMP	40	13.0	1.4 ¹	2.9	2.3 ²	4.8	3.8	NA	NA	NA	NA
19.	REFRIG LUBE OIL PUMP	30	23.1	1.1 ¹	2.2	1.7 ²	4.4	3.4	NA	NA	NA	NA
20.	FM SEAL OIL PUMP	22.5	7.3	0.8 ¹	1.6	1.3 ²	4.2	2.7	NA	NA	NA	NA

Table 3-13

<u>Equipment Driver Cost Options</u>	<u>\$/hr</u>	<u>% Reduction</u>
1. Run existing turbines on fuel oil	2372.6	0
2. Best case using existing equipment	2150.7	9.4
3. Run flash plant exclusively	1810.4	23.7
4. Keep Syn Gas TD, replace Refrig and Air Compressor TD's with flash turbines and generate flash power	1536.1	35.3
5. Run binary plant exclusively	1458.5	38.5
6. Keep Syn Gas TD, replace Refrig and Air Compressor TD's with binary turbines and generate binary power	1410.8	40.5
7. Keep Syn Gas TD, replace Refrig and Air Compressor TD's with flash turbines and buy off-site power	1352.5	43.0
8. Keep Syn Gas TD, replace Refrig and Air Compressor TD's with binary turbines and buy off-site power	1272.0	46.4

The Refrigeration Compressor and Process Air Compressor would be run by new binary cycle turbines. The maximum available off-site electrical power level would be maintained in the plant with the remaining plant equipment run on electrical power generated from a geothermal binary cycle turbine-generator set. The inclusion of in-house electrical generating capacity will also increase plant reliability. With Options 3 and 5 in Table 3-13 giving rates of return of 15.2 percent and 15.8 percent, respectively (from Tables 2-11 and 2-12), it is safe to assume that the optimal solution, listed as Option 8 in Table 3-13, will give an even higher rate of return. Only a detailed economic evaluation of each proposed design scheme, however, can determine the actual internal rate of return for geothermal substitution in the VNP Plant.

SECTION 4

DETAILED ECONOMIC EVALUATION

4.1 INTRODUCTION

An economic evaluation was completed to compare geothermal utilization schemes, which were identified in the energy utilization analysis for detailed cost-benefit analysis, as a conclusion to this feasibility study. The evaluation was accomplished by comparing the energy cost savings incurred by geothermal energy substitution with the capital costs required for plant modifications. Capital cost estimates for geothermal power cycle equipment were based on a combination of the "GEOCOST" program equations and the budget quotations for equipment drivers reported in Section 3. The energy cost savings were calculated by comparing the predicted geothermal brine costs with the fossil fuel cost savings based on detailed plant thermal cycle heat balances. Yearly fuel costs for both fossil fuel and geothermal energy were calculated based on the constant dollar fuel cost projections for the ten year period under consideration appearing in Figure 2-3.

The detailed economic evaluation was conducted in two phases. This two-phase concept allows for verification of the incremental cost effectiveness of a major plant modification over a more modest geothermal application. The objective of Phase I was to eliminate the fossil fuel requirements of the fired package boilers and to minimize the fossil fuel requirements of the P.C.C. Fired Superheater Unit. The Phase II objective was to accomplish Phase I and in addition to completely eliminate the fossil fuel requirements of the P.C.C. Fired Superheater Unit. The accomplishment of Phase II would completely eliminate the requirement of fossil fuel for fired steam production in the VNP Plant, resulting in a 40 percent reduction in plant fossil fuel consumption. The remaining plant fossil fuel consumption constitutes the natural gas used as ammonia feedstock and fuel for the primary gas reform which do not lend themselves to presently economical or practical alternatives.

Total capital costs were calculated for each proposed scheme and incremental benefit-cost ratios were calculated between Phase I and Phase II modifications. Final conclusions and recommendations were drawn based on this detailed economic evaluation.

In the course of discussions with VNP plant personnel regarding new geothermal heat applications to the existing process, it was indicated that less heat input would be required at the primary reformer if the natural gas and process air

were heated to a higher temperature before being charged to the reformer. The resultant energy trade-off will reduce VNP's natural gas consumption in the primary reformer and will increase the rate of return for the application of geothermal energy to the plant. Heat exchangers were sized to preheat process air from 290°F to 325°F and to preheat natural gas feedstock from 54°F to 110°F. This preheat system was included with each of the proposed schemes in the following sections.

4.2 PHASE I MODIFICATION

4.2.1 Introduction

The objective of Phase I is to eliminate the fossil fuel requirements of the fired package boilers and to minimize the fossil fuel requirements of the P.C.C. Fired Superheater Unit. This objective was not chosen arbitrarily, but with a specific purpose in mind. Because VNP is being required to curtail their use of natural gas in the package boilers it would be most appropriate in Phase I to eliminate any further need for these consumers. The alternative facing VNP is to use fuel oil at a higher cost in these package boilers. If required by VNP, this first phase could serve as a demonstration of the feasibility of the application of geothermal energy from the Heber Reservoir to the VNP El Centro plant.

4.2.2 General Modifications

In order to allow the shutdown of the package boilers, total steam consumption must be reduced in the Ammonia Plant. Care has been taken throughout the study to minimize the impact of a geothermal conversion on the existing process conditions by concentrating on the large number of steam turbines in the plant. Steam consumption in the Ammonia Plant is primarily due to steam turbines powering pumps or compressors. Other process units in the plant consume high-pressure, high-temperature steam or use it as a source of heat, therefore making it less feasible to replace with geothermally generated steam.

A major reduction in steam usage is obtained by replacing the Refrigeration and Process Air Compressor turbines with new turbines powered by either lower pressure geothermal steam or a binary fluid such as isobutane. This reduces the 450 psi and 50 psi steam requirements by 69,500 and 86,650 pounds per hour, respectively. The balance of the Ammonia Plant steam turbines, excluding the Synthesis (Syn) Gas Compressor

turbine, will be replaced by running existing or new electric motors. This will reduce the 450 psi steam requirement an additional 134,900 pounds per hour.

The increase in power demand will be met by either onsite or offsite power generation. The increase in electrical demand will be large enough to handle the necessary additional capacity required by the Ammonia Plant motors, plus the additional auxiliary power requirement of the geothermal cycle. The existing 8 MW electrical demand will not be considered in the Phase I calculations.

In order to maintain adequate waste heat recovery from the converted gas stream an additional boiler feedwater exchanger identical to E-106 will be necessary because of the decreased steam flow to the Syn Gas Compressor Turbine. This additional exchanger is shown schematically in Figure 4-1. By eliminating 450 psi steam demand by more than 200,000 pounds per hour in the Ammonia Plant with an additional 50,000 pounds per hour reduction from the cooling tower turbine, client offsites, and plant steam losses, not only will the package boiler steam demand be eliminated, but an additional 101,000 pounds per hour from the Syn Gas Compressor Turbine extraction will be displaced. The result is the lowering of natural gas consumption in the P.C.C. Unit, because of a reduction of 97,000 pounds per hour demand for 1500 psi throttle steam.

While the most substantial changes in the plant utility balance take place in the Ammonia Plant, other changes will be necessary in other locations of the plant. A modified utility balance for the common 450 psi steam system is shown in Figure 4-2, while modified utility balances for the plant water system are shown separately for each scheme. Since the Urea and Nitric Acid Plants remain virtually unchanged, no utility flow diagrams are thought to be necessary for them. The only changes to the Urea and Nitric Acid plants occur at their battery limits, i.e., changes are only in the origin or destination of steam and condensate.

Figures 1-8 and 4-2 can be compared directly. Changes in the overall 450 psi steam supply are readily apparent. The Ammonia Plant will no longer consume 46,100 pounds of steam, but will instead supply 56,680 pounds. The full condensing turbines will be replaced by electric motors, and the "client offsites" demand will be replaced by geothermal flashed steam. The most significant change here is, of course, the elimination of the package boilers.

FIGURE 4-2

PHASE I COMMON 450 psi STEAM SYSTEM

4.2.3 Phase I - Scheme 1, Flash Steam Cycle

4.2.3.1 Introduction

Scheme 1 of the Phase I modification is a geothermal flash steam cycle plant. Both offsite and onsite power generation are considered. Results of the preliminary economics indicate that the flash steam cycle plants will not be as economical as the binary cycle plants, however, both types of plants are being evaluated for comparison.

4.2.3.2 Phase I - Scheme 1 With Onsite Power Generation

4.2.3.2.1 Geothermal Modifications

A preliminary flow diagram for the geothermal flash plant is shown in Figure 4-3. A three stage flash plant was chosen from the preliminary economics. The first stage flashes at 50 psi (65 psia) and supplies steam only to the client offsites. The second and third stages flash the brine at 18 psi (33 psia) and 1 psi (16 psia), respectively, and supply the Refrigeration and Process Air Compressor Turbines, the turbo-generator and the auxiliary steam requirements. The residual brine from the Process Air and Natural Gas Preheaters is charged directly to the second stage flash vessel to have the remaining usable energy extracted in the form of steam. In the flash system employed here the brine is cascaded from stage to stage so that an optimal amount of energy is removed from the brine. In the second and third stages the residual brine from the preceeding stage does not supply sufficient steam so that fresh brine must be introduced directly to the vessel to provide supplemental steam. This provides a valuable degree of operating flexibility.

A modified utility balance for the plant water system is shown in Figure 4-4. Figure 4-4, when compared to Figure 1-3, shows that canal water make-up to the plant water system will be reduced by almost 900 gpm or 46 percent even though the cooling tower make-up increases by over 400 gpm. While canal water is shown as being used to augment the brine reinjection flow, this make-up stream may be replaced in part by waste water.* As can readily be seen, geothermal condensate provides all of the make-up to the Ammonia Plant high pressure boiler feed water system, and 935 gpm of make-up to the plant water system.

*Note - whether or not waste water may be used is yet to be determined by the reservoir leaseholder, and will only be considered on a case by case basis.

FIGURE 4-3

PHASE I - SCHEME 1 WITH ONSITE GENERATION
GEOTHERMAL FLASHED STEAM PLANT

FIGURE 4-4

PHASE I - SCHEME 1 WITH ONSITE GENERATION
PLANT WATER BALANCE

4.2.3.2.2

Capital Costs

Using equations developed and compiled by Battelle Northwest Laboratories for the "GEOCOST" computer program, the specific costs for equipment and appurtenances were calculated and are tabulated in Table 4-1. The turbine costs were taken directly from Table 3-7. All costs were calculated on the basis of 1975 dollars and converted from 1975 to 1977 dollars using an inflation factor of 11.8 percent. This inflation factor was based on CPI records and projections. Engineering and design costs and administrative and indirect costs are not included in Table 4-1. These costs are estimated at 10 percent and 8 percent respectively, of the plant equipment costs, and are tabulated below to give the total project costs:

Plant equipment costs (\$ 1977)	\$20,842,000
Engineering and design (10%)	2,084,000
Administrative and indirect (8%)	<u>1,667,000</u>
TOTAL (\$ 1977)	\$24,593,000

4.2.3.2.3

Operating and Maintenance Costs

Costs resulting from the operation and maintenance of the proposed geothermal equipment were calculated to be \$360,000 per year considering necessary additional personnel, maintenance materials, cooling tower chemicals, and miscellaneous expenditures. Savings arising from the decreased requirement for demineralization chemicals were credited against the O&M costs. It is important to note that the O&M costs of the proposed addition are incremental to existing plant O&M charges.

4.2.3.2.4

Cost Savings

The inherent energy savings with the Phase I plant conversion comes from several sources. The lower consumption of high pressure steam decreases the energy load on the P.C.C. Unit both as a boiler and as a high pressure steam superheater. Preheating the natural gas feedstock and process air to the Ammonia Plant saves on fuel consumed in the Primary Reformer. However, the largest source of energy savings results from the elimination of the package boilers. The savings breakdown is as follows:

Table 4-1

PHASE I, SCHEME 1 PLANT EQUIPMENT COSTS (\$ 1977)
(Includes Onsite Generation)

1.	Brine Transmission Pipeline	\$ 5,887,000
2.	Brine Reinjection Pipeline	1,212,000
3.	Turbines	4,294,000
4.	Condensers	1,921,000
5.	Reinjection Pump	1,415,000
6.	Piping and Insulation	1,027,000
7.	Flash Vessels	937,000
8.	Buildings, Structures, Foundations	903,000
9.	Wet Cooling Tower System	726,000
10.	Instrumentation and Controls	605,000
11.	Switchyard	416,000
12.	Ammonia Plant Electric Motors	377,000
13.	Electrical Support Equipment	329,000
14.	Crane	218,000
15.	Gas Ejectors (Steam Driven)	161,000
16.	Cooling Water Circ. Pump	100,000
17.	C. T. Blowdown Reinjection Pump	95,000
18.	Miscellaneous Support Equipment	82,000
19.	Installation Testing	78,000
20.	Process Heat Exchangers	<u>59,000</u>
	SUBTOTAL (\$ 1977)	\$20,842,000

P.C.C. Unit Waterwalls	51.06 MM BTU/HR*
P.C.C. Unit Superheater	27.00
Package Boilers	152.26
Nat. Gas & Proc. Air Preheat	1.25
TOTAL	231.57 MM BTU/HR

Assuming a 76 percent fossil energy conversion efficiency and a 75 percent plant capacity factor, the total yearly energy savings becomes 2.00×10^{12} BTU per year.

Geothermal energy required to replace the above savings comes in the form of 3,887,450 pounds per hour of brine at 360°F. At 165 BTU per pound and 75 percent capacity factor, the resultant geothermal energy requirement is 4.214×10^{12} BTU per year. The resultant energy cost savings in constant 1977 dollars is tabulated in Table 4-2.

4.2.3.2.5 Economic Evaluation

Table 4-3 illustrates the rate of return calculation to be expected from the Phase I, Scheme 1 conversion with onsite generation. Taxes and Insurance were calculated using the same method as in Section 2.5 with a 20 year depreciation. The rate of return to be expected from the Phase I, Scheme 1 conversion with onsite generation is 5.91 percent, far below the 10 percent return sought by VNP. As was shown in the preliminary economics in Section 3, the cost of offsite electric power is much less than that of onsite electric power. Therefore, it follows that if the Phase I conversion economics were to be calculated without the burden of an onsite generation facility, it would be more likely to appear economically feasible. That likelihood is explored in the next section.

4.2.3.3 PHASE I, SCHEME 1 - WITHOUT ELECTRIC GENERATION

4.2.3.3.1 Geothermal Modifications

The major differences in the proposed Scheme 1 conversion without electric generation are shown in Figures 4-5 and 4-6. Figure 4-5 shows the Plant Water Balance resulting from eliminating the generating facility. The absence of the turbo-generator decreases the amount of condensate produced, ending in an increased requirement for canal

*Note: MM BTU/HR = Million BTU per hour.

Table 4-2

PHASE I, SCHEME 1 ENERGY COST SAVINGS (CONSTANT \$ 1977)
(Includes Onsite Generation)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Net Savings</u>
1980	6,160	3,240	2,920
1981	6,460	3,290	3,170
1982	6,780	3,290	3,490
1983	7,120	3,330	3,790
1984	7,480	3,370	4,110
1985	7,860	3,410	4,450
1986	8,260	3,460	4,800
1987	8,660	3,500	5,160
1988	9,100	3,540	5,560
1989	9,560	3,580	5,980

Table 4-3

CAPITAL COST RECOVERY (CONSTANT \$ 1977)
Phase I, Scheme 1 With Onsite Generation

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 5.91%</u>	<u>PW of Net Savings</u>
1980	\$617,000	\$360,000	\$2,920,000	0.944	\$ 1,834,000
1981	586,000	360,000	3,170,000	0.892	1,984,000
1982	556,000	360,000	3,490,000	0.842	2,167,000
1983	525,000	360,000	3,790,000	0.795	2,309,000
1984	494,000	360,000	4,110,000	0.750	2,442,000
1985	463,000	360,000	4,450,000	0.709	2,572,000
1986	432,000	360,000	4,800,000	0.669	2,681,000
1987	401,000	360,000	5,160,000	0.632	2,780,000
1988	370,000	360,000	5,560,000	0.596	2,879,000
1989	340,000	360,000	5,980,000	0.563	<u>2,973,000</u>
TOTAL:					\$24,621,000
CAPITAL COST:					<u>(24,593,000)</u>
					\$ 28,000

FIGURE 4-5

PHASE I - SCHEME 1 WITHOUT ONSITE GENERATION
PLANT WATER BALANCE

FIGURE 4-6

PHASE I - SCHEME 1 WITHOUT ONSITE GENERATION
GEOTHERMAL FLASHED STEAM PLANT

water make-up to the clear water supply system. Figure 4-6 illustrates the effects of the modification on the proposed Phase I Flash Plant. The final outcome is the reduction in the brine flow requirement from 3,890,000 pounds per hour to 1,980,000 pounds per hour. The lower steam requirement thus creates a lower reinjection brine make-up requirement.

4.2.3.3.2 Capital Costs

Costs incurred due to construction requirements were calculated using the same methods as in Section 4.2.3.2.2. The costs excluding the onsite electric equipment and appurtenances are tabulated in Table 4-4. As before, the costs in the table were calculated in 1975 dollars and converted to 1977 dollars using the 11.8 percent CPI projected inflation rate. The total cost for the Phase I conversion without on-site generation becomes:

Plant Equipment Costs (\$ 1977)	\$11,672,000
Engineering and Design (10%)	1,167,000
Administrative and Indirect (8%)	<u>934,000</u>
TOTAL (\$ 1977)	\$13,773,000

4.2.3.3.3 Operating and Maintenance Costs

Neglecting the onsite electric facility, the incremental costs due to the operation and maintenance of the proposed addition drops to \$113,000 per year. These costs were calculated as before, but with less equipment to operate and maintain (approximately half) the estimated costs have dropped drastically.

4.2.3.3.4 Cost Savings

By eliminating the turbo-generator set from the proposed Phase I conversion, not only do the capital costs decrease but the cost savings increase. A comparison of Table 4-5 with Table 4-2 shows that a portion of the geothermal energy costs have been replaced by cheaper electrical energy costs. The geothermal energy required has been reduced from 4.214×10^{12} BTU per year as reported in Section 4.2.3.3, to 2.144×10^{12} BTU per year. The increase in offsite electrical power demand will be 8400 KW.

4.2.3.3.5 Economic Evaluation

Table 4-6 illustrates a much brighter outlook for the Phase I energy conversions. The rate of return

Table 4-4

PHASE I, SCHEME 1 PLANT EQUIPMENT COSTS (\$ 1977)
(Does Not Include Onsite Generation)

1.	Brine Transmission Pipeline	\$ 3,717,000
2.	Brine Reinjection Pipeline	749,000
3.	Turbines	1,659,000
4.	Condensers	1,202,000
5.	Reinjection Pump	859,000
6.	Buildings, Structures, and Foundations	681,000
7.	Piping and Insulation	634,000
8.	Flash Vessels	476,000
9.	Switchyard	390,000
10.	Ammonia Plant Electric Motors	377,000
11.	Instrumentation and Controls	375,000
12.	Electrical Support Equipment	189,000
13.	Gas Ejectors (Steam Driven)	141,000
14.	C. T. Blowdown Reinjection Pump	68,000
15.	Process Heat Exchangers	59,000
16.	Installation Testing	50,000
17.	Miscellaneous Support Equipment	46,000
18.	Crane	-0-
19.	Cooling Water Circ. Pump	-0-
20.	Wet Cooling Tower System	-0-

SUBTOTAL (\$ 1977): \$11,672,000

Table 4-5

PHASE I, SCHEME 1 ENERGY COST SAVINGS (CONSTANT \$ 1977)
(Does Not Include Onsite Generation)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Electrical Energy Cost</u>	<u>Net Savings</u>
1980	6,160	1,650	1,180	3,330
1981	6,460	1,670	1,210	3,580
1982	6,780	1,670	1,240	3,870
1983	7,120	1,690	1,260	4,170
1984	7,480	1,720	1,290	4,470
1985	7,860	1,740	1,320	4,800
1986	8,260	1,760	1,320	5,180
1987	8,660	1,780	1,320	5,560
1988	9,100	1,800	1,320	5,980
1989	9,560	1,820	1,320	6,420

Table 4-6

CAPITAL COST RECOVERY (CONSTANT \$ 1977)
Phase I, Scheme 1 Without Onsite Generation

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 24.27%</u>	<u>PW of Net Savings</u>
1980	\$346,000	\$113,000	\$3,330,000	0.805	\$ 2,311,000
1981	328,000	113,000	3,580,000	0.648	2,034,000
1982	311,000	113,000	3,870,000	0.521	1,795,000
1983	294,000	113,000	4,140,000	0.419	1,577,000
1984	277,000	113,000	4,470,000	0.337	1,375,000
1985	259,000	113,000	4,800,000	0.272	1,204,000
1986	242,000	113,000	5,180,000	0.219	1,057,000
1987	225,000	113,000	5,560,000	0.176	919,000
1988	207,000	113,000	5,980,000	0.142	804,000
1989	190,000	113,000	6,420,000	0.114	<u>697,000</u>
TOTAL:					\$13,773,000
CAPITAL COST:					<u>(13,773,000)</u>
					\$ -0-

now becomes 24.27 percent, far greater than VNP's minimum rate of return of 10 percent. This serves as a good example of the sensitivity of the rate of return to the source of electric power.

A third combination was also briefly considered. In this scenario the electric generating facility was included in the capital costs of plant modifications but the energy savings calculations did not provide for operating the facility. In other words, the electrical generation facilities would be available only as an emergency standby. The rate of return in this instance came out to be 9.28 percent, very close to the 10 percent minimum required. This means that VNP can afford to construct an onsite flash steam cycle generation facility but cannot afford to operate it as long as offsite electrical costs remain so cheap.

4.2.4 PHASE I - SCHEME 2, BINARY CYCLE

4.2.4.1 Introduction

In the economics of Sections 2 and 3 it would appear that a binary system would be favored over a flashed steam system. Therefore, an analysis of a flashed steam system would not be complete without an analysis of a comparable binary system. The following sections will provide that analysis. First, the system and its necessary equipment will be studied, then the costs and inherent savings will be compared in an economic analysis. Both onsite and offsite power generation will be considered.

4.2.4.2 Phase I - Scheme 2 With Onsite Power Generation

4.2.4.2.1 General Modifications

The previous flashed steam analysis made use of low pressure steam turbines for the Refrigeration and Air Compressor Turbine replacements. In order to utilize the power available in a binary system, high efficiency turbo-expanders would instead be employed as replacements. The remaining turbines in the Ammonia Plant with the exception of the Syn Gas Compressor Turbine would be replaced by electric motors as they would in the flashed steam system. Several changes have been made in the binary cycle from that used for the preliminary economics, primarily by switching to a desuperheating rankine cycle and by desuperheating using condensed isobutane rather than cooling water. The savings in 450 psi and 50 psi steam will remain identical to those of the flashed steam system, and the proposed Ammonia Plant steam system shown in Figure 4-1 applies for this system also.

The only major difference in the Plant Water Balance between the flashed steam system and the binary system is the increased requirement for canal water make-up because of the absence of flashed steam condensate. The total canal water requirement for this binary scheme would be 2550 gpm.

The power required by the motors which would replace the Ammonia Plant turbines, would be about 6.8 megawatts. Auxiliary power required by the proposed binary cycle and electric generation facility totals about 5.4 megawatts, bringing the total required generation capacity to approximately 12.2 megawatts.

The proposed Phase I Binary Plant is illustrated diagrammatically in Figure 4-7. A small 65 psia flash vessel would be necessary to provide the 15,600 pounds per hour of steam required by the "client offsites" (ammonia storage and solution formulation). The binary part of the geothermal plant utilizes isobutane as the working fluid which is heated supercritically through heat exchange with the geothermal brine. The isobutane is then expanded in the Refrigeration and Air Compressor Turbines and the Generator Turbine. The fluid is then desuperheated in an economizer which preheats the condensed isobutane before it is vaporized in the brine heated vapor generator. The brine which exits the isobutane vapor generator is augmented to compensate for the steam taken for the client offsites and is then reinjected.

4.2.4.2.2

Capital Costs

Again using the "GEOCOST" equations, the costs of the proposed plant conversion, associated equipment and other inherent costs were calculated and are tabulated in Table 4-7. The Engineering and Design Costs and the Administrative and Indirect Costs are approximated as 10 and 8 percent respectively. This brings the total installed cost of the conversion facilities to:

Plant Equipment Costs (\$ 1977)	\$18,152,000
Engineering and Design (10%)	1,815,000
Administrative and Indirect (8%)	<u>1,452,000</u>
TOTAL:	\$21,419,000

4.2.4.2.3

Operating and Maintenance Costs

Continuing costs due to the operation and maintenance of the proposed facilities have been approximated

Table 4-7

PHASE I, SCHEME 2 BINARY SYSTEM
PLANT EQUIPMENT COSTS (\$ 1977)
(Includes Onsite Generation)

1.	Brine Transmission Pipeline	\$ 2,862,000
2.	Brine Reinjection Pipeline	977,000
3.	Condensers and Desuperheaters	2,597,000
4.	Turbines	2,088,000
5.	Isobutane Circulation Pump	1,875,000
6.	Piping, Insulation and Tanks	1,600,000
7.	Reinjection Pump	1,036,000
8.	Vapor Generator and Aux. Heaters	957,000
9.	Instrumentation and Controls	864,000
10.	Buildings, Structures, Foundations	828,000
11.	Wet Cooling Tower System	812,000
12.	Switchyard	472,000
13.	Electrical Support Equipment	380,000
14.	Ammonia Plant Electric Motors	377,000
15.	Crane	220,000
16.	Installation Testing	96,000
17.	Miscellaneous Support Equipment	84,000
18.	Flash Vessels	27,000
19.	Gas Ejectors (none required)	-0-
SUBTOTAL (\$ 1977)		\$18,152,000

as \$488,000 per year. As calculated previously, these costs include expenses for additional personnel, maintenance materials, cooling tower chemicals, canal water, and savings for the decreased use of demineralizer chemicals. Again, it should be noted that these costs are incremental to the existing plant O&M costs.

4.2.4.2.4 Cost Savings

The energy savings for the binary system are the same as for the steam system shown in Section 4.2.3.2.4. The potential Phase I energy savings of 2.00×10^{12} BTU per year would be replaced by 3.15×10^{12} BTU per year of geothermal energy in a binary system. Therefore the cost savings displayed in Table 4-8 for a Phase I Binary System show that the Fossil Fuel Savings are identical to those for a Phase I Flashed Steam System. The cost of geothermal energy is less than that of a comparable steam system which shows a higher utilization efficiency for the proposed binary system. This results in a total net savings greater than that of the comparable steam system.

4.2.4.2.5 Economic Evaluation

The result of the calculation of the expected rate of return for a Phase I Binary System with onsite power generation is shown in Table 4-9. The expected rate of return has been calculated to be 10.16 percent. When compared with the 5.91 percent return calculated for a comparable steam system, the binary system comes out far ahead. What is more important is that the 10.16 percent return satisfies VNP's 10 percent minimum requirement. This shows that a Phase I plant modification is economically feasible without the requirement of increased offsite electrical demand.

4.2.4.3 PHASE I - SCHEME 2 WITHOUT ELECTRIC GENERATION

4.2.4.3.1 Geothermal Modifications

The major differences in the proposed Binary Phase I conversion are shown in Figure 4-8. The most obvious change is the elimination of the Turbo-generator turbine, which results in a much lower brine requirement. The brine demand has decreased by about 56 percent from 2,338,000 to 1,041,000 pounds per hour.

Table 4-8

PHASE I, SCHEME 2 BINARY SYSTEM
ENERGY COST SAVINGS (CONSTANT \$ 1977)
(Includes Onsite Generation)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Net Savings</u>
1980	6,160	2,900	3,260
1981	6,460	2,930	3,530
1982	6,780	2,960	3,820
1983	7,120	2,990	4,130
1984	7,480	3,020	4,460
1985	7,860	3,050	4,810
1986	8,260	3,090	5,170
1987	8,660	3,120	5,540
1988	9,100	3,150	5,950
1989	9,560	3,180	6,380

Table 4-9

CAPITAL COST RECOVERY (CONSTANT \$ 1977)
 PHASE I, SCHEME 2 BINARY SYSTEM WITH ONSITE GENERATION

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 10.16%</u>	<u>PW of Net Savings</u>
1980	\$538,000	\$488,000	\$3,260,000	0.908	\$ 2,078,000
1981	511,000	488,000	3,530,000	0.824	2,086,000
1982	484,000	488,000	3,820,000	0.748	2,130,000
1983	457,000	488,000	4,130,000	0.679	2,163,000
1984	430,000	488,000	4,460,000	0.616	2,182,000
1985	403,000	488,000	4,810,000	0.560	2,195,000
1986	376,000	488,000	5,170,000	0.508	2,187,000
1987	349,000	488,000	5,540,000	0.461	2,168,000
1988	323,000	488,000	5,950,000	0.419	2,153,000
1989	296,000	488,000	6,380,000	0.380	<u>2,126,000</u>
TOTAL:					\$21,418,000
CAPITAL COST:					<u>21,419,000</u>
					\$ (1,000)

FIGURE 4-8

PHASE I - SCHEME 2 WITHOUT ONSITE GENERATION
GEOTHERMAL BINARY PLANT

4.2.4.3.2

Capital Costs

Costs incurred for the equipment required were calculated using the same methods as in Section 4.2.3.2.2. The costs excluding the onsite electric equipment and appurtenances are tabulated in Table 4-10. As before the costs are in 1977 dollars. The total cost for the Phase I Binary System conversion without generation facilities becomes:

Plant Equipment Costs (\$ 1977)	\$ 9,184,000
Engineering and Design (10%)	918,000
Administration and Indirect (8%)	<u>735,000</u>
TOTAL (\$ 1977)	\$10,837,000

4.2.4.3.3

Operating and Maintenance Costs

By eliminating the onsite electric facility, the incremental costs due to the operation and maintenance of the proposed addition drops to \$238,000 per year. These costs were calculated as before, but with less equipment to operate and maintain (around half) the costs have dropped appreciably.

4.2.4.3.4

Cost Savings

By eliminating the turbo-generator set from the proposed binary Phase I conversion, not only do the capital costs decrease but the cost savings increase. A comparison of Table 4-11 with Table 4-8 shows that a portion of the geothermal energy costs have been replaced by cheaper electrical energy costs. The geothermal energy required has been reduced from 3.15×10^{12} BTU per year to 1.45×10^{12} BTU per year. The reduction of geothermal energy requires increasing offsite electrical consumption by 63.96 million KWH per year.

4.2.4.3.5

Economic Evaluation

The rate of return for the proposed Phase I conversion utilizing a binary system and with onsite generation of electricity was shown to be 10.16 percent. Table 4-12 illustrates that by eliminating the onsite generation of electricity and purchasing power from offsite sources, the expected rate of return increases to 32.12 percent.

Table 4-10

PHASE I, SCHEME 2 BINARY SYSTEM WITHOUT ONSITE GENERATION
(\$ 1977)

1.	Brine Transmission Pipeline	\$1,710,000
2.	Brine Reinjection Pipeline	465,000
3.	Condensers and Desuperheater	1,493,000
4.	Isobutane Circulation Pump	847,000
5.	Piping, Insulation and Tanks	808,000
6.	Turbines	748,000
7.	Brine Reinjection Pump	524,000
8.	Vapor Generator and Aux. Heaters	517,000
9.	Buildings, Structures, Foundations	502,000
10.	Instrumentation and Controls	471,000
11.	Switchyard (for offsite power)	420,000
12.	Ammonia Plant Electric Motors	377,000
13.	Electrical Support Equipment	181,000
14.	Installation Testing	49,000
15.	Miscellaneous Support Equipment	45,000
16.	Flash Vessel	27,000
17.	Crane (not required)	-0-
18.	Gas Ejectors (not required)	-0-
19.	Wet Cooling Tower System (not required)	-0-
		<u>\$9,184,000</u>

Table 4-11

PHASE I, SCHEME 2 BINARY SYSTEM
ENERGY COST SAVINGS (CONSTANT \$ 1977)

(Does not Include Onsite Generation)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Electrical Energy Cost</u>	<u>Net Savings</u>
1980	6,160	1,330	1,370	3,460
1981	6,460	1,350	1,400	3,710
1982	6,780	1,360	1,430	3,990
1983	7,120	1,370	1,460	4,290
1984	7,480	1,390	1,500	4,590
1985	7,860	1,400	1,540	4,920
1986	8,260	1,420	1,540	5,300
1987	8,660	1,430	1,540	5,690
1988	9,100	1,450	1,540	6,110
1989	9,560	1,460	1,540	6,560

Table 4-12

CAPITAL COST RECOVERY (CONSTANT \$ 1977)
 PHASE I, SCHEME 2 BINARY SYSTEM WITHOUT ONSITE GENERATION

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 32.12%</u>	<u>PW of Net Savings</u>
1980	\$272,000	\$238,000	\$3,460,000	0.757	\$ 2,233,000
1981	258,000	238,000	3,710,000	0.573	1,842,000
1982	245,000	238,000	3,990,000	0.434	1,522,000
1983	231,000	238,000	4,290,000	0.328	1,253,000
1984	218,000	238,000	4,590,000	0.249	1,029,000
1985	204,000	238,000	4,920,000	0.188	842,000
1986	190,000	238,000	5,300,000	0.142	692,000
1987	177,000	238,000	5,690,000	0.108	570,000
1988	163,000	238,000	6,110,000	0.082	468,000
1989	150,000	238,000	6,560,000	0.062	<u>383,000</u>
TOTAL:					\$10,834,000
CAPITAL COST:					<u>(10,837,000)</u>
					\$ (3,000)

Another alternative was also briefly considered. In this scenario it was assumed that the generation facility cost would be included in the cost of the plant, but the cost of running the generator would be neglected. In other words the generator would be constructed, but only used for emergency power. The result was an overall expected rate of return of 12.46 percent. This shows that should this alternative be desirable to augment plant reliability by providing substantial emergency power, it would also provide the necessary rate of return to be economically feasible.

4.3 PHASE II MODIFICATIONS

4.3.1 Introduction

As stated previously, the purpose of the second phase of the geothermal energy utilization conversion is to eliminate the need for the natural gas fired P.C.C. Unit. In order to accomplish this task, it will be necessary to replace the high pressure steam powered Synthesis (Syn) Gas Compressor Turbine. The reason for this becomes apparent when studying the Plant Steam Balance. In eliminating the P.C.C. Unit, a portion of the high pressure steam generation and all of the high pressure steam superheater capacity would be omitted. Since saturated 1500 psi steam is essentially useless for powering a high speed turbine, another method must be provided to operate the Syn Gas Compressor. Three schemes have been explored both from an energy and an economic standpoint. The first applies a hybrid energy system utilizing both flashed steam turbines and a binary two-stage ammonia turbo-expander. The second scheme utilizes low pressure steam turbines, and the third employs a binary system with isobutane turbo-expanders.

In the preceeding Phase I Section, it was shown that the onsite generation of electricity is not economically feasible for geothermal flash steam cycle plants. Unless the electricity cost base increases at a greater rate than predicted, the generation facilities when considered on an incremental basis will remain infeasible in the coming years. Therefore, onsite generation will be considered in the proposed Phase II conversions only where the plant energy conversion indicates that an acceptable return can be expected.

All of the Phase II modifications are to include Phase I modifications, therefore the economics for all Phase II alternatives will reflect the total conversion costs and expenses as well as the total conversion energy and cost savings.

4.3.2 General Modifications

In eliminating the P.C.C. Unit, there would still be a substantial amount of 1500 psi waste heat-generated steam remaining. This steam would be superheated in a modified E-103 (Converted Gas Waste Heat Boiler) to 1204.6 BTU per pound, expanded to 450 psi at saturated conditions, then used to meet the process requirements of the Ammonia and Urea Plants and the miscellaneous demands of the overall Plant. After satisfying these 450 psi steam requirements, additional waste heat is still available to the 1500 psi system. A proposed Phase II System will utilize the remaining heat from the 1500 psi system which in turn will be combined with geothermal energy to supply power to the replacement turbines. The boiler feedwater system remains virtually unchanged from Phase I except for differences in flow rates. The major difference is the increase in flow (212,000 to 294,000 pounds per hour). The boiler feedwater flow was decreased for Phase I, but when combined with Phase II, it can be returned to its design rate.

Figure 4-9 illustrates the proposed Phase II Ammonia Plant 450 psi steam system, and can be compared with the 450 psi steam header shown in Figure 4-2 for Phase I. As can readily be seen, the only changes of significance are the amount of steam supplied to the header, and the amount sent to the Common Plant Header. The reduction in steam required in the Common Plant Header is primarily due to the changes proposed in the Urea Plant Steam System shown in Figure 4-10. When compared to the existing system in Figure 1-7, the major change becomes obvious: the hydraulic supply pump and auxiliary carbamate pump turbines have been omitted, thus reducing the Urea Plant 450 psi steam requirement. This is necessary mainly to reduce Plant steam consumption, and because the 450 psi steam would no longer be superheated, which is required for expansion in existing high speed turbines. These two turbines, as are the other turbines throughout the plant (with three large exceptions) are to be replaced by new and existing electric motors. The only changes between the Phase I and Phase II Common 450 psi Steam Header, Figures 4-2 and 4-11, are in the flow rates. Since the Urea Plant steam requirement would be reduced from 48,440 pounds to 32,800 pounds, the Ammonia Plant steam production would therefore be reduced.

4.3.3 Phase II - Scheme 1, Hybrid System

4.3.3.1 Introduction

The first scheme investigated for Phase II combines both flashed steam and binary systems. Scheme 1

FIGURE 4-9

- - - - - WATER
 ——— STEAM
 LB ——— FLOW, POUNDS PER HOUR
 GPM ——— FLOW, GALLONS PER MINUTE
 h ——— ENTHALPY, BTU PER POUND
 F ——— TEMPERATURE, °F
 PSI ——— POUNDS PER SQ. INCH, GAGE
 P ——— POUNDS PER SQ. INCH, ABS.

PHASE II AMMONIA PLANT 450 psi STEAM SYSTEM

FIGURE 4-10

PHASE II UREA PLANT STEAM SUPPLY SYSTEM

PHASE II COMMON 450 psi STEAM SYSTEM

FIGURE 4-11

of Phase II would be compatible only with Scheme 1 of Phase I because of system similiarity. Scheme 1 of Phase I provides a flashed steam system for powering the Refrigeration and Air Compressor Turbines as does Scheme 1 of Phase II. In addition to these flash steam turbines, Phase II Scheme 1 calls for a Syn Gas Compressor Turbine powered by an ammonia binary cycle. Due to the poor results from flashed steam power generation in Phase I, no onsite power generation will be considered in this scheme.

4.3.3.2 Phase II - Scheme 1 Analysis

4.3.3.2.1 Geothermal Modifications

As mentioned in the introduction, this scheme is compatible with Scheme 1 of Phase I. In addition to the Phase I flashed steam system, the Syn Gas Compressor Turbine would be replaced by a turbo-expander powered by a binary fluid, in this case ammonia, in a sub-critical Rankine power cycle. The proposed binary segment of the system is illustrated in Figure 4-12. Figures 4-12 and 4-13, the proposed Scheme 1 Deaerator Flow Diagram, combined with Figure 4-9, the Ammonia Plant 450 psi Steam System, can be compared with the Phase I Ammonia Plant Steam System in Figure 4-1. What can be seen from this comparison are the additional modifications necessary to convert Phase I-Scheme 1 into Phase II-Scheme 1. As was noted earlier, the excess waste heat recovered in the 1500 psi steam system is utilized in the binary system and augmented by geothermal energy. The Scheme 1 binary system requires a lower amount of geothermal heat than would a comparable system because the heat supplied by the 1500 psi system comprises about one-third of the total energy requirement. The proposed turbine is a high efficiency two-stage turbo-expander. It expands 435,000 pounds per hour of ammonia from 1288 psia to 266 psia, developing a design horsepower of 12,760 at 12,300 rpm, the identical conditions of the existing turbine (rated horsepower is 14,000). The overall plant water balance has changed from Phase I as a comparison of Figures 4-5 and 4-14 will reveal, but the changes are in flow rates only.

The proposed Phase II-Scheme 1 Flash Plant is shown in Figure 4-15, and when compared with Figure 4-6, the Phase II additions become obvious. A new "First" Stage (95 psia) has been added to provide steam for the 80 psi Urea Plant Heater. The Second Stage (65 psia) flash will also provide steam to the 50 psi Urea Plant Heater. The residual brine from the new Boiler Feedwater supplement preheater is

FIGURE 4-12

PHASE II - SCHEME 1
AMMONIA PLANT HYBRID SYSTEM

FIGURE 4-13

PHASE II - SCHEME 1
AMMONIA PLANT DEAERATOR

FIGURE 4-14

FIGURE 4-15

PHASE II - SCHEME I
 GEOTHERMAL FLASHED STEAM PLANT

shown flowing to the Third Stage (33 psia) flash vessel and the residual from the Binary Plant exchangers is piped to the Fourth Stage (16 psia) flash vessel. This brings the total supply brine flow to 3,237,000 pounds per hour. It should be noted that just less than one-third of this geothermal energy is required in the proposed binary cycle, which is used solely to power the Syn Gas Compressor Turbine.

4.3.3.2.2 Capital Costs

Tabulated in Table 4-13 is the total equipment cost for both Phase I and Phase II, Scheme 1. The approximate price for the turbo-expander to replace the Synthesis Gas Compressor Turbine was supplied by the Rotoflow Corporation. The costs were calculated as before in 1975 dollars and converted from 1975 to 1977 dollars using the CPI factor of 11.8 percent. Adding the engineering and design costs and the administrative and indirect costs, the total construction costs become:

Plant Equipment Costs (\$ 1977)	\$18,582,000
Engineering and Design (10%)	1,858,000
Administrative and Indirect (8%)	<u>1,487,000</u>
TOTAL (\$ 1977)	\$21,927,000

4.3.3.2.3 Operating and Maintenance Costs

The costs for operating and maintaining the combined Phase I (Scheme 1) and Phase II (Scheme 1) conversion have been approximated as \$252,000 per year. This is a \$139,000 per year increase for the Phase II addition over Phase I. These costs as previously stated include additional personnel, maintenance materials, cooling tower chemicals, canal water, and a reduction in Demineralization Plant chemical costs.

4.3.3.2.4 Cost Savings

The savings incurred by eliminating fossil fuel, partially offset by the expense of geothermal heat and purchased electrical energy, are itemized in Table 4-14. The fossil fuel savings are based on the shutdown of the P.C.C. Unit and package boilers, and the energy saved in the Primary Reformer as a result of preheating the natural gas and process air. The total fossil energy eliminated is itemized below:

Table 4-13

PHASE II, SCHEME 1 PLANT EQUIPMENT COSTS (\$ 1977)
(Includes Phase I Equipment Costs)

1.	Brine Transmission Pipeline	\$ 5,107,000
2.	Brine Reinjection Pipeline	1,065,000
3.	Condensers	2,309,000
4.	Turbines	2,268,000
5.	Reinjection Pump	1,235,000
6.	Piping, Insulation and Tanks	1,035,000
7.	Heat Exchangers (Binary Plant)	1,007,000
8.	Buildings, Structures, Foundations	896,000
9.	Instrumentation and Controls	815,000
10.	Binary Feed Pump	625,000
11.	Ammonia Plant Electric Motors	525,000
12.	Flash Vessels	508,000
13.	Switchyard	459,000
14.	Electric Support Equipment	325,000
15.	Gas Ejectors	141,000
16.	C. T. Blowdown Reinjection Pump	95,000
17.	Installation Testing	89,000
18.	Miscellaneous Support Equipment	78,000
19.	Process Heat Exchangers (Included above)	-0-
20.	Crane	-0-
21.	Cooling Water Pump	-0-
22.	Wet Cooling Tower System	-0-
SUBTOTAL		\$18,582,000

Table 4-14

PHASE II, SCHEME 1 ENERGY COST SAVINGS (CONSTANT \$ 1977)
(Includes Phase I Savings)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Electrical Energy Cost</u>	<u>Net Savings</u>
1980	8,650	2,700	1,630	4,320
1981	9,080	2,740	1,670	4,670
1982	9,530	2,740	1,700	5,090
1983	10,000	2,770	1,740	5,490
1984	10,510	2,810	1,780	5,920
1985	11,040	2,840	1,830	6,370
1986	11,610	2,880	1,830	6,900
1987	12,170	2,910	1,830	7,430
1988	12,790	2,950	1,830	8,010
1989	13,430	2,980	1,830	8,620

P.C.C. Waterwalls	70.00 MM BTU/HR
P.C.C. Preheat	11.33
P.C.C. Superheat	90.00
Package Boilers	152.26
Nat. Gas & Proc. Air Preheat	1.25
	<hr/>
	324.84 MM BTU/HR

This is an increase of 40 percent over the Phase I savings shown in Section 4.2.3.2.4. As was calculated in Scheme 1 of Phase I, using a 76 percent fossil energy conversion efficiency and an average 75 percent plant capacity factor, the amount of fossil energy eliminated becomes 2.81×10^{12} BTU per year. The amount of geothermal energy required to fill the power and heat requirements left by eliminating this energy is 3.509×10^{12} BTU per year, from a brine flow of 3,237,000 pounds per hour, along with the offsite electrical energy requirement, which would be supplied to the plant motors and to provide auxiliary power to the geothermal facilities, of 11,600 KW or 76.1×10^6 KWH per year.

4.3.3.2.5 Economic Evaluation

The calculation of the expected rate of return from the total geothermal conversion of Phase II, Scheme 1 is shown in Table 4-15. As can be seen, the overall rate of return has been calculated to be 18.39 percent. It should be noted that this rate of return has been calculated for the overall conversion, not the incremental return for this Phase II scheme over Phase I. To determine the incremental feasibility of a Phase II, Scheme 1 conversion, a benefit/cost ratio was calculated using a 10 percent rate of return as required by VNP. The result is shown below:

PW of Phase II Incremental Net Savings (@ 10%) in \$1000

PW of Phase II Incremental Capital Cost in \$1000

$$= \frac{(32,060 - 25,067)}{(21,927 - 13,773)} = 0.86$$

Since the benefit/cost ratio is less than one, the incremental rate of return is less than 10 percent. This means that, although it has an internal rate of return of 18.39 percent, Phase II, Scheme 1 would not be an acceptable incremental investment over Phase I, Scheme 1 on the basis of the 10 percent

Table 4-15

CAPITAL COST RECOVERY (CONSTANT \$ 1977)
PHASE II, SCHEME 1 - HYBRID SYSTEM

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 18.39%</u>	<u>PW of Net Savings</u>
1980	\$550,000	\$252,000	\$4,320,000	0.845	\$ 2,973,000
1981	523,000	252,000	4,670,000	0.713	2,777,000
1982	495,000	252,000	5,090,000	0.603	2,619,000
1983	468,000	252,000	5,490,000	0.509	2,428,000
1984	440,000	252,000	5,920,000	0.430	2,248,000
1985	413,000	252,000	6,370,000	0.363	2,071,000
1986	385,000	252,000	6,900,000	0.307	1,923,000
1987	358,000	252,000	7,430,000	0.259	1,766,000
1988	330,000	252,000	8,010,000	0.219	1,627,000
1989	303,000	252,000	8,620,000	0.185	<u>1,492,000</u>
TOTAL:					\$21,924,000
CAPITAL COST:					<u>(21,927,000)</u>
					\$ (3,000)

minimum rate of return set by VNP. An appropriate alternative will be explored in the following section, "Phase II-Scheme 2."

4.3.4 Phase II - Scheme 2, Flash System

4.3.4.1 Introduction

As was shown in the previous section, providing a hybrid cycle to replace the Syn Gas Turbine proved to give less than a 10 percent return when considered incrementally to Phase I without onsite generation. This section will present the results of an alternative approach, namely a replacement turbine for the Syn Gas Compressor which is powered by low-pressure saturated steam. This scheme is also compatible with Scheme 1 of the Phase I modifications.

4.3.4.2 Phase II - Scheme 2 Analysis

4.3.4.2.1 Geothermal Modifications

The proposed flashed steam system is shown diagrammatically in Figures 4-16 and 4-17. These two illustrations can be related to Figures 4-12 and 4-15 of the previous section. When compared, the major contrasts become readily apparent. In Figure 4-16 the binary cycle has been replaced by a small two-stage flash cycle. The steam generated from this high pressure feedwater is added to the steam generated in the geothermal flash plant shown in Figure 4-17. For obvious reasons, the brine flow through the binary heaters of Scheme 1 has been omitted and instead, the brine flow to the third and fourth stage flash vessels have been increased to accommodate a higher steam requirement. The additional steam generation is needed for the proposed Syn Gas Compressor Turbine, and the increased auxiliary steam requirements. Condensate flow from the Geothermal Condenser Hotwell, shown in Figure 4-18, is being used to decrease the canal water make-up rate to the clarifier. The 965 gpm make-up rate to the clarifier is one-third less than that required in Scheme 1, as shown in Figure 4-14, while the total canal water make-up rate is higher to maintain brine reinjection inventory.

The only other modification to Scheme 1 made for Scheme 2 shows up as a lower boiler feedwater return rate in Figure 4-19. This decrease is offset by an increased make-up rate from the geothermal condensate polisher. The steam rate to the deaerator heater has also been reduced, because of the higher heat content of the deaerator charge stream. A modified Ammonia Plant steam balance is not shown, as the differences are not considered significant.

FIGURE 4-16

PHASE II - SCHEME 2
AMMONIA PLANT FLASHED STEAM SYSTEM

FIGURE 4-17

PHASE II - SCHEME 2
GEOTHERMAL FLASHED STEAM PLANT

FIGURE 4-18

FIGURE 4-19

PHASE II - SCHEME 2
AMMONIA PLANT DEAERATOR

4.3.4.2.2

Capital Costs

While there are major differences between the costs of the individual items listed in Table 4-16 for Scheme 2 and the items in Table 4-13 for Scheme 1, the total costs are very similar. The total costs for construction are calculated as before and are listed below:

Plant Equipment Costs (\$ 1977)	\$18,747,000
Engineering and Design (10%)	1,875,000
Administrative and Indirect (8%)	<u>1,500,000</u>
TOTAL (\$ 1977)	\$22,122,000

Again, the costs include both the Phase I and Phase II (Scheme 2) conversion.

4.3.4.2.3

Operating and Maintenance Costs

The costs for operating and maintaining the geothermal facility and all its appurtenances will increase for Scheme 2 to \$279,000 per year. This is mostly due to the increased consumption of cooling tower chemicals necessary for the additional cooling tower capacity.

4.3.4.2.4

Cost Savings

The cost savings displayed in Table 4-17 for the Scheme 2 scenario show that the geothermal energy costs are about 13 percent greater than that of Scheme 1 in Table 4-14. This is solely due to the increased brine flow (3,701,000 pounds per year) necessary for the greater steam demand. Electrical energy costs are less (66.6×10^6 KWH per year), but the resultant net savings are only 3 percent lower than that of Scheme 1, with identical fossil fuel energy savings.

4.3.4.2.5

Economic Evaluation

The tabulated capital cost recovery and rate of return calculation is shown in Table 4-18. The resultant capital cost recovery tabulation shows that the expected rate of return from this scheme is 17.13 percent. This compares with the greater 24.3 percent expected rate of return from Phase I, Scheme 1. Now checking the incremental benefit-cost ratio between Phase I and Phase II, we compare the present worth net energy cost savings at 10 percent with the present worth capital costs (all in 1000 dollars) and get:

$$B/C = \frac{(30,731 - 25,067)}{(22,122 - 13,773)} = 0.68$$

Table 4-16

PHASE II, SCHEME 2 PLANT EQUIPMENT COSTS (\$ 1977)
(Includes Phase I Equipment Costs)

1. Brine Transmission Pipeline	\$ 5,603,000
2. Brine Reinjection Pipeline	1,215,000
3. Turbines	2,676,000
4. Condensers	1,932,000
5. Reinjection Pump	1,364,000
6. Piping and Insulation	1,050,000
7. Buildings, Structures, Foundations	994,000
8. Flash Vessels	985,000
9. Instrumentation and Controls	610,000
10. Ammonia Plant Electric Motors	525,000
11. Wet Cooling Tower Systems	459,000
12. Switchyard	429,000
13. Electrical Support Equipment	322,000
14. Gas Ejectors (Steam Driven)	161,000
15. Cooling Water Pump	101,000
16. C. T. Blowdown Reinjection Pump	95,000
17. Installation Testing	89,000
18. Miscellaneous Support Equipment	78,000
19. Process Heat Exchangers	59,000
20. Crane	-0-
<hr/>	
SUBTOTAL:	\$18,747,000

Table 4-17

PHASE II, SCHEME 2 ENERGY COST SAVINGS (CONSTANT \$ 1977)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Electrical Energy Cost</u>	<u>Net Savings</u>
1980	8,650	3,090	1,430	4,130
1981	9,080	3,130	1,460	4,490
1982	9,530	3,130	1,490	4,910
1983	10,000	3,170	1,530	5,300
1984	10,510	3,210	1,560	5,740
1985	11,040	3,250	1,600	6,190
1986	11,610	3,290	1,600	6,720
1987	12,170	3,330	1,600	7,240
1988	12,790	3,370	1,600	7,820
1989	13,430	3,410	1,600	8,420

Table 4-18 -

**CAPITAL COST RECOVERY (CONSTANT \$ 1977)
PHASE II, SCHEME 2 - FLASHED STEAM SYSTEM**

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Incremental O&M</u>	<u>Energy Savings</u>	<u>PWF @ 17.15%</u>	<u>PW of Net Savings</u>
1980	\$555,000	\$279,000	\$4,130,000	0.854	\$ 2,815,000
1981	527,000	279,000	4,490,000	0.729	2,686,000
1982	500,000	279,000	4,910,000	0.622	2,569,000
1983	472,000	279,000	5,300,000	0.531	2,416,000
1984	444,000	279,000	5,740,000	0.454	2,278,000
1985	416,000	279,000	6,190,000	0.387	2,127,000
1986	389,000	279,000	6,720,000	0.331	2,003,000
1987	361,000	279,000	7,240,000	0.282	1,861,000
1988	333,000	279,000	7,820,000	0.241	1,737,000
1989	305,000	279,000	8,420,000	0.206	1,614,000
TOTAL:					\$22,106,000
CAPITAL COST:					(22,122,000)
					\$ (16,000)

Since the B/C ratio is also less than one, the incremental cost of building the Phase II modifications would not provide an incremental benefit of 10 percent internal rate of return as required by VNP.

4.3.5 Phase II - Scheme 3, Binary System

4.3.5.1 Introduction

The preliminary economics and Phase I calculations indicate that the binary cycle will give a higher rate of return than the flash cycle. Therefore our analysis would not be complete without a Phase II binary system. As was shown in Section 4.2.4 for Scheme 2 of Phase I, the Refrigeration and Air Compressor Turbines can economically be replaced by isobutane powered turbo-expanders. In a Phase II conversion to a binary system, the Syn Gas Compressor Turbine would also be replaced by an isobutane powered turbo-expander. As Schemes 1 and 2 of Phase II were compatible only to Scheme 1 of Phase I, Scheme 3 of Phase II will only be compatible with Scheme 2 of Phase I. The overall result to the plant is the same as for Schemes 1 and 2 of the Phase II conversion, namely, the package boilers will have been shut down as a result of the Phase I application and the requirement for the P.C.C. Unit would be eliminated in Phase II. The smaller applications of geothermal energy will remain essentially identical in Scheme 3 to Schemes 1 and 2. Due to the encouraging results with binary cycle onsite power generation in Phase I, onsite generation will be considered in Phase II in three steps: 1) no onsite generation; 2) generation of enough power to meet additional demands; and 3) generation of the total plant power requirement including the existing 8 MW demand.

4.3.5.2 Phase II - Scheme 3 Analysis

4.2.5.2.1 Geothermal Modifications

The Ammonia Plant high pressure steam system shown in Figure 4-20 is very similar to those shown in Figures 4-12 and 4-16 for Schemes 1 and 2. The only significant differences lie in the high pressure system energy utilization. In Scheme 3 the surplus energy from the waste heat system will be utilized to heat a portion of the isobutane in a super-critical rankine power cycle necessary to run the turbo-expanders. The balance of the isobutane is heated with geothermal brine.

FIGURE 4-20

PHASE II - SCHEME 3
AMMONIA PLANT STEAM SYSTEM

Total canal water make-up to the VNP Plant will increase for the Phase II cycles over comparable Phase I cycles, in spite of increased geothermal condensate, due primarily to larger cooling tower make-up requirements. The Urea Plant and Common Area Steam Balances will remain basically unchanged from those presented for previous Phase II modifications.

The next three illustrations, Figures 4-21, 4-22, and 4-23 show the geothermal plant flow diagrams for each of the three steps of application of onsite power generation. When compared to the Scheme 1 and 2 geothermal plants in Figures 4-15 and 4-17, the relative simplicity of the Scheme 3 plant becomes obvious. The two-step increase in isobutane demand only requires increases in brine flow to the vapor generator by way of the brine by-pass line.

4.3.5.2.2 Capital Costs

Capital costs for equipment modifications have been calculated as in previous cases using a combination of the "GEOCOST" program equations and vendor quotations referred to in Section 3. Total capital costs have been calculated for each of the three cases considered under Scheme 3, including the costs incurred in a Phase I modification. The total construction costs are tabulated in Tables 4-19, 4-20 and 4-21 for each of the magnitudes of power generation considered.

4.3.5.2.3 Operating and Maintenance Costs

The estimated O&M costs are again calculated here considering the increased labor requirements, maintenance materials, cooling tower chemicals, canal water make-up, and miscellaneous expenditures. The overall costs are then offset slightly by the decreased demineralizer chemical requirement. These costs are as before incremental to the existing plant O&M costs:

<u>Case</u>	<u>\$/YEAR</u>
Without Onsite Power Generation	\$285,000
With Onsite Power Generation	561,000
With Total Onsite Power Generation	741,000

FIGURE 4-21

PHASE II - SCHEME 3 WITHOUT ONSITE GENERATION
GEOTHERMAL BINARY PLANT

FIGURE 4-22

PHASE II - SCHEME 3 WITH ONSITE GENERATION
GEOTHERMAL BINARY PLANT

FIGURE 4-23

PHASE II - SCHEME 3 WITH TOTAL ONSITE GENERATION
GEOTHERMAL BINARY PLANT

Table 4-19

PHASE II, SCHEME 3 BINARY SYSTEM
 PLANT EQUIPMENT COSTS (\$ 1977)
 (No Onsite Generation)

1. Condensers and Desuperheaters	\$ 1,905,000
2. Brine Transmission Pipeline	1,801,000
3. Brine Reinjection Pipeline	514,000
4. Iso-butane Circulation Pump	1,290,000
5. Piping, Insulation, Tanks	1,152,000
6. Turbines	977,000
7. Vapor Generator and Aux. Heaters	871,000
8. Buildings, Structures, Foundations	863,000
9. Wet Cooling Tower System	808,000
10. Instrumentation and Controls	675,000
11. Brine Reinjection Pump	576,000
12. Switchyard	486,000
13. Ammonia Plant Electric Motors	377,000
14. Electrical Support Equipment	297,000
15. Installation Testing	102,000
16. Miscellaneous Support Equipment	88,000
17. Flash Vessels	60,000
18. Crane (None required)	-0-
19. Gas Ejectors (None required)	-0-
Plant Equipment Cost:	\$12,842,000
Engineering and Design (10%):	1,284,000
Administrative and Indirect (8%):	<u>1,027,000</u>
	\$15,153,000

Table 4-20

PHASE II, SCHEME 3 BINARY SYSTEM
 PLANT EQUIPMENT COSTS (\$ 1977)
 (With Onsite Generation)

1. Condensers and Desuperheaters	\$ 3,468,000
2. Brine Transmission Pipeline	3,115,000
3. Brine Reinjection Pipeline	1,173,000
4. Iso-butane Circulation Pump	2,609,000
5. Turbines	2,537,000
6. Piping, Insulation, Tanks	2,201,000
7. Vapor Generators and Aux. Heaters	1,292,000
8. Brine Reinjection Pump	1,223,000
9. Instrumentation and Controls	1,155,000
10. Buildings, Structures, Foundations	1,092,000
11. Wet Cooling Tower System	815,000
12. Switchyard	544,000
13. Electrical Support Equipment	498,000
14. Ammonia Plant Electric Motors	377,000
15. Crane	222,000
16. Installation Testing	142,000
17. Miscellaneous Support Equipment	117,000
18. Flash Vessels	60,000
19. Gas Ejectors	-0-

Plant Equipment Cost: \$22,640,000

Engineering and Design (10%): 2,264,000

Administrative and Indirect (8%): 1,811,000

\$26,715,000

Table 4-21

PHASE II, SCHEME 3 BINARY PLANT
 PLANT EQUIPMENT COSTS (\$ 1977)
 (With Total Onsite Generation)

1. Condensers and Desuperheaters	\$ 5,075,000
2. Brine Transmission Pipeline	3,917,000
3. Brine Reinjection Pipeline	1,580,000
4. Iso-butane Circulation Pump	3,392,000
5. Turbines	3,087,000
6. Pipeline, Insulation and Tanks	2,851,000
7. Vapor Generators and Aux. Heaters	1,627,000
8. Brine Reinjection Pump	1,608,000
9. Instrumentation and Controls	1,579,000
10. Buildings, Structures, Foundations	1,300,000
11. Wet Cooling Tower System	819,000
12. Switchyard	698,000
13. Electrical Support Equipment	646,000
14. Ammonia Plant Electric Motors	377,000
15. Crane	230,000
16. Installation Testing	181,000
17. Miscellaneous Support Equipment	146,000
18. Flash Vessels	60,000
19. Gas Ejectors (None required)	<u>-0-</u>
Plant Equipment Costs:	\$29,173,000
Engineering and Design (10%):	2,917,000
Administrative and Indirect (8%):	<u>2,334,000</u>
	\$34,424,000

4.3.5.2.4

Cost Savings

Energy savings due to the elimination of the Package Boilers, the P.C.C. Unit, and an amount of the natural gas combusted in the Ammonia Plant Primary Reformer are identical for Schemes 1 and 2 and Scheme 3 without onsite generation. This is appropriate, of course, in order to compare the three scenarios on the same level. The alternative energy required, however, varies considerably from one scheme to the next, depending on the type of power cycle used. The cost savings for Scheme 3 without onsite power generation is listed in Table 4-22, and can be compared directly with the savings listed for Schemes 1 and 2 in Tables 4-14 and 4-17, respectively. The total net savings shows a 14 percent increase over the Scheme 1 Hybrid System, the next highest cost saver.

The following two tabulations, Tables 4-23 and 4-24, show that the greater the magnitude of onsite power generation, the lower the actual cost savings (and the higher the construction costs). The reason for this becomes clear when considering that the present offsite electric power available is of a much lower cost than the cost of generating onsite power geothermally.

4.3.5.2.5

Economic Evaluation

Rates of return which have been used throughout this study to determine the feasibility or compare the relative values of the various scenarios have again been calculated for the Scheme 3 alternatives, and are shown in tabular form in Tables 4-25, 4-26 and 4-27. The return given for the case without onsite power generation in Table 4-25 can be compared directly to the returns determined for Schemes 1 and 2 in Tables 4-15 and 4-18, respectively. While the expected return for the hybrid Scheme 1 would be 18.39 percent and 17.13 percent for the flashed steam Scheme 2 system, the economics for Scheme 3 results in a much higher expected yield of 34.56 percent for the binary system of geothermal energy application.

Furthermore, with the generation of enough power to meet the additional electrical demands required for the Phase II binary conversion, the expected return would be 14.55 percent. In the third case, however, with total onsite power generation including the existing 8 MW of electrical demand, the return to be expected for the Phase II binary conversion drops below the VNP 10 percent minimum, to 7.34 percent. Incremental benefit-cost ratios

Table 4-22

PHASE II, SCHEME 3 BINARY SYSTEM
WITHOUT ONSITE POWER GENERATION
ENERGY COST SAVINGS (CONSTANT \$ 1977)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Electrical Energy Cost</u>	<u>Net Savings</u>
1980	8,650	1,680	1,820	5,150
1981	9,080	1,700	1,860	5,520
1982	9,530	1,710	1,900	5,920
1983	10,000	1,730	1,940	6,330
1984	10,510	1,750	1,990	6,770
1985	11,040	1,770	2,040	7,230
1986	11,610	1,790	2,040	7,780
1987	12,170	1,810	2,040	8,320
1988	12,790	1,820	2,040	8,930
1989	13,430	1,840	2,040	9,550

Table 4-23

PHASE II, SCHEME 3 BINARY SYSTEM
WITH ONSITE POWER GENERATION
ENERGY COST SAVINGS (CONSTANT \$ 1977)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Geothermal Energy Cost</u>	<u>Net Savings</u>
1980	8,650	3,820	4,830
1981	9,080	3,860	5,220
1982	9,530	3,900	5,630
1983	10,000	3,950	6,050
1984	10,510	3,990	6,520
1985	11,040	4,030	7,010
1986	11,610	4,070	7,540
1987	12,170	4,110	8,060
1988	12,790	4,150	8,640
1989	13,430	4,200	9,230

Table 4-24

PHASE II, SCHEME 3 BINARY SYSTEM
WITH TOTAL ONSITE POWER GENERATION
ENERGY COST SAVINGS (CONSTANT \$ 1977)

Values in \$1000 per year

<u>Year</u>	<u>Fossil Energy Savings</u>	<u>Offsite Power Savings</u>	<u>Geothermal Energy Cost</u>	<u>Net Savings</u>
1980	8,650	1,120	5,150	4,620
1981	9,080	1,150	5,200	5,030
1982	9,530	1,180	5,260	5,450
1983	10,000	1,200	5,320	5,880
1984	10,510	1,230	5,370	6,370
1985	11,040	1,260	5,430	6,870
1986	11,610	1,260	5,480	7,390
1987	12,170	1,260	5,540	7,890
1988	12,790	1,260	5,600	8,450
1989	13,430	1,260	5,650	9,040

Table 4-25

PHASE II, SCHEME 3 (BINARY SYSTEM)
 WITHOUT ONSITE POWER GENERATION
 CAPITAL COST RECOVERY (CONSTANT \$ 1977)

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Increased O&M</u>	<u>Energy Savings</u>	<u>PWF @ 34.56%</u>	<u>PW of Net Savings</u>
1980	\$380,000	\$285,000	\$5,150,000	0.743	\$ 3,332,000
1981	361,000	285,000	5,520,000	0.552	2,690,000
1982	342,000	285,000	5,920,000	0.410	2,170,000
1983	323,000	285,000	6,330,000	0.305	1,745,000
1984	304,000	285,000	6,770,000	0.227	1,403,000
1985	285,000	285,000	7,230,000	0.168	1,119,000
1986	266,000	285,000	7,780,000	0.125	904,000
1987	247,000	285,000	8,320,000	0.093	724,000
1988	228,000	285,000	8,930,000	0.069	581,000
1989	209,000	285,000	9,550,000	0.051	<u>462,000</u>
TOTAL:					\$15,130,000
CAPITAL COST:					<u>(15,153,000)</u>
					\$ (23,000)

Table 4-26

PHASE II, SCHEME 3 (BINARY SYSTEM)
WITH ONSITE POWER GENERATION
CAPITAL COST RECOVERY (CONSTANT \$ 1977)

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Increased O&M</u>	<u>Energy Savings</u>	<u>PWF @ 14.55%</u>	<u>PW of Net Savings</u>
1980	\$671,000	\$561,000	\$4,830,000	0.873	\$ 3,141,000
1981	637,000	561,000	5,220,000	0.762	3,065,000
1982	604,000	561,000	5,630,000	0.665	2,969,000
1983	570,000	561,000	6,050,000	0.581	2,858,000
1984	536,000	561,000	6,520,000	0.507	2,749,000
1985	503,000	561,000	7,010,000	0.443	2,634,000
1986	469,000	561,000	7,540,000	0.386	2,513,000
1987	436,000	561,000	8,060,000	0.337	2,380,000
1988	402,000	561,000	8,640,000	0.295	2,265,000
1989	369,000	561,000	9,230,000	0.257	<u>2,133,000</u>
TOTAL:					\$26,707,000
CAPITAL COST:					<u>(26,715,000)</u>
					\$ (8,000)

Table 4-27

PHASE II, SCHEME 3 (BINARY SYSTEM)
WITH TOTAL ONSITE POWER GENERATION
CAPITAL COST RECOVERY (CONSTANT \$ 1977)

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Increased O&M</u>	<u>Energy Savings</u>	<u>PWF @ 7.34%</u>	<u>PW of Net Savings</u>
1980	\$864,000	\$741,000	\$4,620,000	0.932	\$ 2,810,000
1981	821,000	741,000	5,030,000	0.868	3,010,000
1982	778,000	741,000	5,450,000	0.809	3,180,000
1983	734,000	741,000	5,880,000	0.753	3,317,000
1984	691,000	741,000	6,370,000	0.702	3,466,000
1985	648,000	741,000	6,870,000	0.654	3,585,000
1986	605,000	741,000	7,390,000	0.609	3,681,000
1987	562,000	741,000	7,890,000	0.567	3,735,000
1988	518,000	741,000	8,450,000	0.529	3,804,000
1989	475,000	741,000	9,049,000	0.492	<u>3,849,000</u>
TOTAL:					\$34,437,000
CAPITAL COST:					<u>(34,424,000)</u>
					\$ 13,000

were calculated for the three Scheme 3 cases, by comparing them to similar Phase I cases of binary power cycle with and without onsite power generation. The first binary case, without onsite generation, showed an incremental benefit-cost ratio of 2.91, while the second binary case, with onsite generation, showed an incremental benefit-cost ratio of 2.18. Incremental benefit-cost ratios equal to or greater than one indicate an acceptable incremental investment in going from Phase I to Phase II. The third binary case, with total onsite power generation, showed an incremental benefit-cost ratio of 0.64, which would be expected from the low internal rate of return.

4.4 SUMMARY

Data from each of the cases considered in the detailed economic evaluation is summarized in Table 4-28. The compression work listed refers to the amount of geothermal turbine work done to replace the three largest steam turbines in the plant. All Phase I schemes require substituting geothermal powered turbines for the Refrigeration Compressor and Air Compressor Turbines. All Phase II schemes require substituting geothermal powered turbines for the Refrigeration Compressor, Air Compressor, and Syn Gas Compressor Turbines.

The total plant power demand listed includes power to supply new and existing process plant motors, geothermal plant auxiliary power requirements, and the present 8,000 KW plant electrical demand. Various combinations of offsite and onsite power generation were considered. Offsite power refers to electrical demand supplied by the local utility, namely the Imperial Irrigation District, while onsite power refers to geothermal power generation.

Incremental cooling water requirements were included to indicate the amount of additional cooling tower capacity required for each case. Incremental canal water make-up requirements were also indicated, where numbers in parentheses indicate reductions in total canal water requirements. Components of canal make-up water required to maintain brine reinjection inventory may be reduced if plant waste water can be successfully substituted.

Incremental benefit-cost ratios were calculated for each Phase II case to check the acceptability of the incremental investment over a comparable Phase I case.

4.5 CONCLUSIONS OF THE DETAILED ECONOMIC ANALYSIS

From Table 4-28 it can be concluded that, if offsite power is made available to the VNP Plant under the present

TABLE 4-28

DETAILED ECONOMIC EVALUATION SUMMARY	PHASE I				PHASE II				
	Scheme 1		Scheme 2		Scheme 1	Scheme 2	Scheme 3		
	Without Onsite Power Generation	With Onsite Power Generation	Without Onsite Power Generation	With Onsite Power Generation	Without Onsite Power Generation	Without Onsite Power Generation	Without Onsite Power Generation	With Onsite Power Generation	With Total Onsite Power Generation
POWER CYCLE	FLASH	FLASH	BINARY	BINARY	HYBRID	FLASH	BINARY	BINARY	BINARY
RESERVOIR TEMP, °F	360	360	360	360	360	360	360	360	360
BRINE FLOW, 10 ³ lb/hr	1,978	3,887	1,041	2,338	3,237	3,701	1,354	3,084	4,155
COMPRESSION WORK, Hp	11,772	11,772	11,772	11,772	24,532	24,532	24,532	24,532	24,532
TOTAL PLANT POWER DEMAND, KW*	16,400	17,500	17,700	20,200	19,600	18,100	20,900	24,200	26,200
OFFSITE POWER DEMAND, KW	16,400	8,000	17,700	8,000	19,600	18,100	20,900	8,000	-0-
ONSITE GENERATOR OUTPUT, KW	-0-	9,500	-0-	12,200	-0-	-0-	-0-	16,200	26,200
INCREMENTAL C.W. REQ'D, GPM	4,000	19,000	3,900	31,500	7,000	14,000	14,500	51,200	73,800
INCREMENTAL CANAL WATER, GPM	(110)	300	(50)	650	(120)	175	200	1,060	1,580
PLANT MODIFICATION COST, \$10 ³ , (1977)	13,773	24,593	10,837	21,419	21,927	22,122	15,153	26,715	34,424
INTERNAL R of R @ 10 YRS, %	24.3	5.9	32.1	10.2	18.4	17.1	34.6	14.5	7.3
INCREMENTAL BENEFIT-COST RATIO	NA	NA	NA	NA	0.86	0.68	2.91	2.18	0.64

*Includes Present 8,000 KW Demand

rate structure, the geothermal flash steam and binary power cycles can return a rate greater than the 10 percent minimum required by VNP, with the binary cycle return rate consistently higher for a comparable case. If, however, offsite power is not made available to the VNP Plant or is not available under the present rate structure, only the geothermal binary power cycle can return a rate greater than the 10 percent minimum required by VNP while providing onsite geothermal power generation. Until present electrical rates change, no geothermal power cycle considered can economically replace the present 8 MW offsite electrical demand, however, providing onsite power generation would reduce plant susceptibility to intermittent offsite power outages.

Also from Table 4-28 it can be seen that only the geothermal binary power cycle gives an acceptable incremental benefit-cost ratio for a Phase II modification. This indicates that only the geothermal binary cycle is economically acceptable for a Phase II modification, which results in eliminating all fossil fuel requirements for steam production in the VNP Plant.

Comparing plant modification costs in Table 4-28 between the Phase I and Phase II geothermal binary power cycles, there is only approximately \$5,000,000 separating the two phases for comparable cases. Considering the "on and off" costs of constructing the plant geothermal modifications in two stages (which are not included in the Phase II costs) it may be more economical to make a complete Phase II modification rather than staging the modification in two phases. If this is true then a proof-of-concept geothermal demonstration can be found for the VNP plant which is smaller than a Phase I modification, if required by VNP.

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Appendix A

DERIVATION OF COOLING TOWER INCREMENTAL COST FACTOR

The incremental cooling tower cost is defined as:

$$\frac{\text{Increase in C.T. Load}}{\text{Geothermal C.T. Load}} \left[\text{Geothermal C.T. Cost} \right]$$

which is:

$$(1) \quad \frac{(Q_R)_g - (Q_R)_f}{(Q_R)_g} \left[\$ \text{ C.T.} \right]_g$$

where: Q_R = Heat rejection load in C.T.
 g = Geothermal plant cycle
 f = Fossil plant cycle

It is most convenient to calculate the heat rejection load (Q_R) in each plant cycle in terms of the amount of work output from the cycle (W) and the cycle thermal efficiency (EFF) for comparison of two plant cycles. By definition:

$$(2) \quad EFF = \frac{W}{Q_A} \quad \text{where } Q_A = \text{Heat added to the cycle}$$

and

$$(3) \quad Q_A = W + Q_R$$

Therefore, we can eliminate Q_A from these two independent equations and find Q_R as a function of W and EFF as follows:

From equation (2):

$$Q_A = \frac{W}{EFF}$$

and substituting into equation (3):

$$\frac{W}{EFF} = W + Q_R$$

$$Q_R = \frac{W}{EFF} - W$$

$$Q_R = W \left[\frac{1}{EFF} - 1 \right] = W \frac{(1-EFF)}{EFF}$$

Simplifying equation (1):

$$1 - \left[\frac{(Q_R)_f}{(Q_R)_g} \right] \left[\$ \text{ C.T.} \right]_g$$

Therefore, we can find the ratio of heat rejected in the fossil fuel plant to the heat rejected in the geothermal cycle plant as follows:

$$(Q_R)_f = W_f \frac{(1-EFF_f)}{EFF_f}$$

$$(Q_R)_g = W_g \frac{(1-EFF_g)}{EFF_g}$$

Therefore:

$$(4) \quad \frac{(Q_R)_f}{(Q_R)_g} = \frac{W_f (1-EFF_f) EFF_g}{W_g (1-EFF_g) EFF_f}$$

However, since the amount of work done by the geothermal cycle is exactly the amount of work previously done by the fossil fuel cycle,

$$W_f = W_g$$

and

$$\frac{W_f}{W_g} = 1$$

Equation (4) simplifies to:

$$\frac{(Q_R)_f}{(Q_R)_g} = \frac{(1-EFF_f) EFF_g}{(1-EFF_g) EFF_f}$$

and therefore, equation (1) becomes:

$$\text{Incremental C.T. Cost} = \left[1 - \frac{(1-EFF_f) EFF_g}{(1-EFF_g) EFF_f} \right] \left[\$ \text{ C.T.} \right]_g$$

Appendix B

STEAM CYCLE THERMAL EFFICIENCY

Calculation of the VNP Plant steam cycle thermal efficiency is required to determine the amount of fossil fuel required to produce a given amount of shaft work. This calculation is important because it allows us to compare the cost of operating the existing thermal cycle with the cost of operating an alternative thermal cycle, namely a geothermal energy cycle.

A simplified form of the VNP Plant steam cycle is shown in Figure B-1. This figure is a compilation of Figures 1-3 through 1-10. It can be seen from Figure B-1 that there is a large amount of heat and mass flow entering and leaving the cycle. Since the Rankine Cycle Efficiency is only defined for the closed portion of the cycle, it is necessary to account for the amount of heat that is lost from the cycle and the amount of heat that is providing shaft work. Heat losses from the cycle are in two forms: 1. Mass flow heat losses, such as process steam and header steam losses; and 2. process heat losses, such as 150 psi and 50 psi process heaters. Therefore, the Rankine Cycle Efficiency is defined as:

$$\text{efficiency} = \frac{WK_{OUT}}{(Q_{ADDED})_{NET}}$$

Where:

$$WK_{OUT} = \text{Turbine Shaft Work}$$

FIGURE B-1

SIMPLIFIED PLANT STEAM CYCLE

$$(Q_{\text{ADDED}})_{\text{NET}} = \frac{\text{Waste Heat} + \text{Fossil Fuel} - \text{Mass Flow} - \text{Process}}{\text{Heat Losses} \quad \text{Heat Losses}}$$

Table B-1 summarizes the information necessary to calculate $(Q_{\text{ADDED}})_{\text{NET}}$ by tabulating the waste heat added, fossil fuel heat added, mass flow heat losses, and process heat losses. The only modification to the numbers in Table B-1 is the inclusion of the boiler efficiency with the fossil fuel heat added to determine the actual amount of fossil fuel burned for steam production. Assuming a boiler efficiency of 76%, based on boiler vendor data, the calculation of $(Q_{\text{ADDED}})_{\text{NET}}$ becomes:

$$\begin{aligned} (Q_{\text{ADDED}})_{\text{NET}} &= \frac{(2.44 + 2.85 - 1.57 - 0.64)}{0.76} \times 10^8 \text{ BTU/HR} \\ &= 4.00 \times 10^8 \text{ BTU/HR} \end{aligned}$$

The calculation of W_{KOUT} is made by adding the design horsepower ratings of the steam driven turbines and converting the total horsepower to BTU's per hour.

$$W_{\text{KOUT}} = 31,324 \text{ Hp} (2544.4 \text{ BTU/Hp-hr}) = 0.800 \times 10^8 \text{ BTU/HR}$$

Therefore, the Gross Rankine Cycle Efficiency becomes:

$$\begin{aligned} \text{eff} &= \frac{W_{\text{KOUT}}}{(Q_{\text{ADDED}})_{\text{NET}}} = \frac{0.800 \times 10^8 \text{ BTU/HR}}{4.00 \times 10^8 \text{ BTU/HR}} = 0.20 \text{ or } 20\% \end{aligned}$$

TABLE B-1

Waste Heat Added

BFW & Condensate Heater (E-409)	=	0.385×10^8	BTU/HR
BFW Heater (E-709)	=	0.579×10^8	BTU/HR
BFW Heater (E-106)	=	0.063×10^8	BTU/HR
Feedwater Economizer (D-104)	=	0.433×10^8	BTU/HR
Reform Gas W.H. Boiler (E-105)	=	0.908×10^8	BTU/HR
Converted Gas W.H. Boiler (E-103)	=	0.076×10^8	BTU/HR
TOTAL	=	2.444×10^8	BTU/HR

Fossil Fuel Heat Added

Package Boilers	142,220 lb/hr (1070.6 BTU/lb)	=	1.52×10^8	BTU/HR
PCC Boiler	109,200 lb/hr (578.7 BTU/lb)	=	0.63×10^8	BTU/HR
PCC Superheater	302,000 lb/hr (148.7 BTU/lb)	=	0.45×10^8	BTU/HR
PCC Superheater	23,000 lb/hr (1088.4 BTU/lb)	=	0.25×10^8	BTU/HR
TOTAL		=	2.85×10^8	BTU/HR

Mass Flow Heat Losses $(\dot{m}h)_{OUT}$

Process Steam	97,700 lb/hr (1298.6 BTU/lb)	=	1.269×10^8	BTU/HR
Steam Header	23,460 lb/hr (1298.6 BTU/lb)	=	0.305×10^8	BTU/HR
Deaerator	3,000 lb/hr (1167 BTU/lb)	=	0.035×10^8	BTU/HR
Feedwater	9,610 lb/hr (228 BTU/lb)	=	0.022×10^8	BTU/HR
TOTAL =	133,770 lb/hr		1.631×10^8	BTU/HR

 $(\dot{m}h)_{IN}$

Demin Make-up	93,770 lb/hr (44.8 BTU/lb)	=	0.042×10^8	BTU/HR
Demin Make-up	40,000 lb/hr (44.8 BTU/lb)	=	0.018×10^8	BTU/HR
TOTAL =	133,770 lb/hr		0.060×10^8	BTU/HR

$$\text{Mass Flow Heat Losses} = (\dot{m}h)_{OUT} - (\dot{m}h)_{IN} = 1.571 \times 10^8 \text{ BTU/HR}$$

Process Heat Losses $(\dot{m}\Delta h)_{LOST}$

Urea Plant	32,100 lb/hr (857 BTU/lb)	=	0.275×10^8	BTU/HR
Urea Plant	15,560 lb/hr (901 BTU/lb)	=	0.140×10^8	BTU/HR
Urea Plant	4,700 lb/hr (917 BTU/lb)	=	0.043×10^8	BTU/HR
MEA Purifier	3,000 lb/hr (966 BTU/lb)	=	0.029×10^8	BTU/HR
Client Offsites	11,160 lb/hr (958 BTU/lb)	=	0.107×10^8	BTU/HR
Client Offsites	4,440 lb/hr (1031 BTU/lb)	=	0.046×10^8	BTU/HR
TOTAL =	70,960 lb/hr		0.640×10^8	BTU/HR

Many of the turbines included in the calculation of the Gross Rankine Cycle Efficiency are used in the plant steam cycle itself for circulating feedwater, cooling water, and demineralized water. This horsepower requirement along with the electrical power used to operate and control the plant steam cycle constitute the plant auxiliary power requirement. Both the existing thermal cycle and any alternative thermal cycle have auxiliary power requirements which must be satisfied to operate the cycle. Therefore in analyzing alternative cycles we compare them on the basis of their net thermal cycle efficiencies, which accounts for the amount of plant auxiliary power required to run each cycle. The auxiliary power is always stated as a percentage of the gross power output, therefore we define the net power output as:

$$\text{Net Power Output} = \text{Gross Power Output} (1 - \% \text{ Auxiliary Power})$$

This equation can also be written in terms of the thermal cycle efficiencies, namely:

$$\text{Net Cycle Eff} = \text{Gross Cycle Eff} (1 - \% \text{ Auxiliary Power})$$

For the purposes of our calculations we assume an auxiliary power requirement for the VNP Plant steam cycle of 13 percent. Therefore, the net thermal cycle efficiency becomes:

$$\text{Net Cycle Efficiency} = 0.20 (1 - 0.13) = 0.174 \text{ or } 17.4\%$$

Appendix C

LEVELIZED UNIT FUEL COSTS

fuel expenses as would be produced by the sum of the present worth of the annual fuel expenses throughout the entire study period. The levelized unit fuel costs were calculated for the study period in order to eliminate the added complexity of dealing with yearly escalation, thereby simplifying the analysis to one cost for each fuel during the study period. The calculation of levelized unit fuel costs was done on a present worth basis for the year 1980 and covers the study period of 1980 through 1989. Nominal fuel costs, calculated by inflating the constant dollar fuel costs in Figure 2-3 at the rate of 6.5 percent per year, as shown in Figure C-1, were used and an interest rate of 8 percent was assumed for the calculation. An inflation rate of 6.5 percent appears to be both realistic and conservative based on government budget announcements, congressional appropriation history, recent wage settlements in basic industries, and projected labor productivity rates. Levelized unit fuel costs are calculated by dividing the sum of the present worth fuel costs by the sum of the present worth factors for the study period. The calculation is summarized in Table C-1.

FIGURE C-1

Table C-1

LEVELIZED UNIT FUEL COSTS
Period 1980-1989

End of Year	PWF 8%	Purchased Electricity		Fuel Oil		Natural Gas		One-Phase Brine		Two-Phase Brine	
		\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW
1977		5.86		2.66		1.52		0.900		0.75	
1978		6.38		2.97		1.90		0.966		0.81	
1979		6.94		3.31		2.47		1.04		0.86	
1980	0.926	7.55	6.99	3.69	3.41	3.21	2.97	1.11	1.031	0.93	0.858
1981	0.857	8.21	7.04	4.11	3.52	3.59	3.08	1.20	1.025	0.99	0.853
1982	0.794	8.94	7.10	4.58	3.64	4.01	3.18	1.28	1.019	1.07	0.850
1983	0.735	9.72	7.15	5.11	3.76	4.49	3.30	1.38	1.014	1.15	0.845
1984	0.681	10.58	7.20	5.70	3.88	5.02	3.42	1.48	1.011	1.24	0.842
1985	0.630	11.51	7.25	6.35	4.00	5.61	3.53	1.60	1.005	1.33	0.838
1986	0.584	12.25	7.15	7.09	4.14	6.27	3.66	1.72	1.003	1.43	0.835
1987	0.540	13.04	7.04	7.90	4.27	7.01	3.79	1.85	0.997	1.54	0.831
1988	0.500	13.89	6.95	8.81	4.41	7.84	3.92	1.99	0.994	1.66	0.828
1989	0.463	14.80	6.85	9.82	4.55	8.76	4.06	2.14	0.992	1.78	0.826
TOTAL:	6.710		70.72		39.58		34.91		10.091		8.41
LEVELIZED UNIT FUEL COST:		10.53		5.90		5.20		1.50		1.25	

FIXED CHARGE RATE CALCULATION

calculated in the same manner as a government owned utility, since both organizations secure capital by means of long term loans and both organizations pay no income taxes. Therefore, the fixed charge rate is calculated by the following equation:

$$FCR = CRF + p$$

where: FCR = Fixed Charge Rate
 CRF = Capital Recovery Factor
 p = Property taxes and insurance

$$CRF = \frac{i (1 + i)^N}{(1 + i)^N - 1}$$

where: i = Loan Interest Rate
 N = Loan Repayment Period

For the VNP economic analysis, the following assumptions are made:

i = 8%
 N = 10 years
 p = 2.32% (Property tax) + 0.19% (Property Insurance)
 p = 2.51%

$$FCR = \frac{0.08 (1 + 0.08)^{10}}{(1 + 0.08)^{10} - 1} + 0.0251$$

$$FCR = 0.149 + 0.0251 = \underline{0.174}$$

Appendix E

CALCULATION OF BRINE FLASHING PRESSURES

thermal flash steam plant at VNP. The first stage will flash brine at 65 psia to satisfy the present 50 psi steam requirements. The second and third flash stages are chosen to optimize the energy extracted from the brine as a driving force for the single and double entry saturated steam turbines. To optimize the turbine inlet pressures, equations from work done by Milora and Tester were used. With the first flash stage pressure set at 65 psia and a temperature, T , of 298°F (758°R), and a sink temperature, T_0 , of 126°F (586°R) corresponding to a turbine backpressure of 4"HgA, T_1^{OPT} and T_2^{OPT} become:

$$T_1^{OPT} = (T_0 T^2)^{1/3} = [586(758)^2]^{1/3} = 696^\circ\text{R} = 236^\circ\text{F} \text{ (23.3 psia)}$$

$$T_2^{OPT} = (T_0 T_1^{OPT})^{1/2} = [586(696)]^{1/2} = 638^\circ\text{R} = 178^\circ\text{F} \text{ (7.4 psia)}$$

This optimized flash system results in a sub-atmospheric steam pressure (7.4 psia) at the third flash stage. This condition is generally undesirable for the following reasons:

1. Increased specific volume of the steam with resulting larger piping, valves and fittings.
2. More complicated plant start-up.
3. Possible in-leakage of oxygen, causing corrosion in piping and equipment, and resulting in more condensate polishing required.

To avoid sub-atmospheric pressures, the third flash stage is maintained slightly above atmospheric pressure at 16 psia. On this basis, the second stage flash pressure is computed to give an optimum between 65 psia and 16 psia. Therefore, T_1^{OPT} is computed as:

$$T_1^{OPT} = (T \times T_2^{OPT})^{1/2} \quad \text{where: } T = 758^\circ\text{R (65 psia)}$$

$$T_2^{OPT} = 216^\circ\text{F} = 676^\circ\text{R (16 psia)}$$

$$T_1^{OPT} = [758(676)]^{1/2} = 716^\circ\text{R} = 256^\circ\text{F (33 psia)}$$

The brine flash conditions are therefore:

First Stage	65 psia
Second Stage	33 psia
Third Stage	16 psia