**ECONOMIC STUDY
FOR
GEOTHERMAL STEAM PRODUCTION
OF
ELECTRIC POWER**

**For
OCCIDENTAL EXPLORATION & PRODUCTION COMPANY
BAKERSFIELD, CALIFORNIA**

18 March 1977

**by
ROGERS ENGINEERING CO., INC.**

Job. S-77006

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In reply refer to: S-77006

19 March 1977

Mr. Charles C. Horace
Chief Engineer and
Executive Vice President
Occidental Exploration and
Production Company
5000 Stockdale Highway
Bakersfield, California 93309

Subject: Economic Study of Geothermal Steam Production
for Electric Power Generation

Dear Mr. Horace:

Enclosed are six copies of the subject Economic Study.

The economic comparison graph shown in Section 2.3 indicates the comparisons between the cost of geothermal, nuclear, coal, and oil fueled power plants.

We will be glad to discuss this study at your convenience.

Very truly yours,

H. Rogers, Jr.
President

HR, JR.:bg

Enclosures: Economic Study (6)

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1.0

INTRODUCTION

This report presents the results of economic analyses of geothermal electric power production facilities using selected geothermal resource temperature characteristics and relates the cost of power and rate of return on investment thus obtained to those being experienced at present and as projected from nuclear and fossil-fuel generating facilities. The results are set down in a manner to permit easy economic comparison of the various options of electric power generation.

1.1

Purpose

It is intended that this study will be a management assist in evaluating the rate of return on invested project capital and the resulting cost of electricity generated from geothermal resources as related to existing alternative generation methods. The resulting electric energy cost is compared with the selected alternative electric generation and their costs.

1.2

Scope

This economic study is general in nature and does not relate to a specific site or resource. The study briefly develops the technical assumptions and balances required to have operating systems. Four geothermal resources are studied. Three are liquid dominated (hot brine) reservoirs with bottom hole (well) temperatures of 400°F, 450°F and 500°F. The fourth resource is vapor dominated

as depicted by The Geysers. All liquid dominated resources are considered for double flash systems to maximize power production efficiency.

Geothermal facilities cost estimates were prepared for each resource and costed at first quarter 1977. The vapor dominated reservoir power plant cost estimate is to be taken from the Pacific Gas and Electric Co.'s application to build its most recent power plant at The Geysers, Unit 15.

Cost comparisons with existing alternative power generating facilities are made with reference to the cost of power and from these facilities in approximate comparative sizes.

Data on alternative electric generation source fuels such as nuclear, coal and oil have been developed from published data in journals, trade magazines and by the Federal Power Commission in the time periods 1962 to 1977.

This study develops in detail the return on investment for geothermal facilities (wells; gathering and reinjection; and power plant facilities). The return on investment with respect to selling price of steam or electricity is developed for each resource.

2.0

SUMMARY

This section summarizes the elements of the report including geothermal power plant and facilities identification, cost estimates and economic analyses.

2.1

Geothermal Facilities Description

The geothermal facilities considered in this study comprise the following elements as defined below and identified in Figure 2.1.

Area 1 - Wells - The components of this area are: a hydrothermal resource having bottom hole temperatures of 400°F, 450°F or 500°F; production wells each capable of producing a flow of 750,000 lbs./hour of geothermal fluid and in sufficient number for producing 55 MW (gross) electric power from the selected resource each equipped with necessary valved top works for pressure and safety relief and connections for tie to collecting system; injection wells in the quantity required for disposal of unused geothermal condensate from start-up ponds, and low pressure separators, and blowdown from cooling tower, each well being complete with valved top work.

Area 2 - Gathering and Reinjection System

This area comprises: all field piping, valves, etc. required to collect the geothermal brine from the production wells and deliver to high pressure satellite steam separators located in the geothermal field; the high pressure steam and hot water piping from the satellite separators to the low pressure steam separators and the high pressure steam connection at the power plant; all geothermal condensate piping from the start-up ponds, from the low pressure steam separators and the power plant, and blowdown from the cooling tower; all required pumps and valves; and the start-up ponds located at the satellite high pressure separators.

Area 3 - Power Plant

This area comprises the power plant building and all required power plant equipment including the following major equipment elements: 55 MW dual pressure/entry condensing turbine generator, direct contact low level steam condenser,

FIGURE: 2.1
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BASIC AREAS OF
 GEOTHERMAL ELECTRIC
 POWER SYSTEMS

2 stage steam jet noncondensable gas evacuating equipment with intercondenser and silencer, condenser cooling water circulating system with hot well pumps, cooling tower, interconnecting piping and pumps; station power transformer; and all required piping, electrical work and controls.

Area 4 - Transmission

This area includes step up transformers, and required switchgear and substation components for connection to a high voltage transmission line.

2.2 Geothermal Facilities Cost

Cost estimates for all geothermal facilities were developed in section 4.0 of the report. Economic analysis of project expenditures is discussed in section 5.0.

The cost of steam or selling price of steam is presented in Figure 5.2 as a function of return on investment in wells; gathering and reinjection system. Case 1 assumes electric power plant operation in 1982 the 5th year of the project. Costs are escalated seven percent each year from 1977 through 1985.

Case 1 shows the change in return with various resource temperatures. With a selling price of steam of 18 mills per kilowatt-hour the return on investment is the following:

<u>Resource</u>	<u>Return</u>
400°F	10.4
450°F	14.5
500°F	16.5
Vapor	30.0

Case 2 shows the economics of owning the wells; gathering and reinjection facilities and power plant. The return is that obtained at various selling prices of electricity. The return on investment for various resources at an electricity selling price in 1982 of 35 mills per kilowatthour is:

<u>Resource</u>	<u>Return</u>
400°F	7.8
450°F	9.3
500°F	10.4
Vapor	21.3

Case 1 presents selling price of steam. Case 2 presents selling price of electricity. The cost of the power plant in mills per kilowatthour, Table 5.2, can be added to the appropriate Case 1 steam sales price to obtain selling price of electricity from Case 1.

2.3

Economic Comparison

The geothermal costs, project timing and assumptions are quite clear. There is also a great amount of published data on capital costs for nuclear, and coal plants coming on production. However, very little is available on the fuel costs and plant operation and maintenance for these plants in the future. It is so uncertain that it distorts the comparison.

The estimated fixed cost on nuclear, coal and oil (if building any more oil) is so large in comparison to the total cost of elec-

tricity (fixed charges, operation and maintenance, and fuel) of geothermal electric power generation this is presented graphically in Figure 2.2. The Fuel and Operation and Maintenance from the latest available data is dotted above the fixed cost blocks for the various plants. By 1982 it is purely a guess what the costs will be for nuclear, coal and oil fuel.

This points out that geothermal is indeed a natural resource, can be developed, and be competitive with nuclear, coal and oil. If one chooses to increase the selling cost of electricity above 35 mills per kilowatthour the return on various geothermal investments can be calculated from the plotted data.

3.0 GEOHERMAL FACILITIES DESCRIPTION

3.1 Resource Conditions

Each study case in this report assumes that the wells drilled into the hydrothermal resource will produce 750,000 lb/hr. Three different downhole temperatures, namely 400°F, 450°F, and 500°F are assumed and the variation in well and equipment requirements are calculated based on producing 55,000 kW of electric power at the plant generator terminals (gross generator output). It is further assumed that conversion of the resource can be effected by utilizing a dual pressure flash steam system and a dual and entry pressure condensing steam turbine. The noncondensable gas content of the first flash steam is as assumed to be 1% wt.

The above assumptions as to resource characteristics and utilization are based on a non-specific site. At a specific site, the actual hot water composition would be used to optimize the power cycle.

Figure 3.1 shows the basic elements of the double flash steam technology as applied to a hydrothermal resource.

3.2 Production and Reinjection Wells

3.2.1 Well Location Plan

It is assumed that in either the production or reinjection well area that the well spacing will be one well for a 20-acre area placing the wells approximately 1000 ft. apart. It is

FIGURE: 3.1
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DOUBLE FLASH
 STEAM TECHNOLOGY

further assumed that the reinjection well area will be about 12,000 feet distant from the production well area.

The entire area is assumed to be one of reasonably accessible valley sections along with rolling type foothills without great elevational changes.

3.2.2 Production Wells

The number and schedule for drilling production wells assumes that these wells have been developed using a casing size to yield the assigned 750,000 lb/hr production rate. It is also assumed that these wells will decay in production over a ten year period to 50% of the specified initial rate and then flow at this rate for the rest of the years of useful life. This decay period is based on analyses of test data obtained on a few existing hydrothermal wells. No extensive history of actual performance is available.

3.2.3 Reinjection Wells

It is assumed that these wells will have been set up for casing sized to accept a reinjection flow of 1,000,000 lb/hr into an underground zone suited to long term constant (non-decay) type flow.

3.3 Gathering and Reinjection Systems

3.3.1 Steam and Hot Water Gathering

The production well is flowed by allowing a portion of the hot water to flash into steam. Previous studies have shown that one of the more economical gathering systems is to allow several wells to flow into a satellite steam-water separator strategically located in the resource field. From each satellite the high pressure steam and residual hot water are discharged into separate piping networks terminating near the power plant connection points. For this study, the maximum flow quantity handled by each field satellite is assumed to be the flow from four production wells.

At each field satellite, a startup and test flow pond is included to preclude slugging the production wells during startup and shutdown of the power plant.

All of the residual hot water from the satellite is flashed (near the power plant) in the low pressure steam-water separator. This low pressure steam is piped into the second entry section of the steam turbine and the residual water is sent to the separator drum booster pumps for reinjection.

3.3.2 Reinjection

Water to be reinjected originates from three sources:

- a. Startup pond pumps, (High Pressure Separator)
- b. Cooling tower overflow sump pump, and
- c. Low pressure separator drum booster pumps.

The major steady flow is from source (c). This flow is discharged to the rejection wells through a piping network.

Allowance has been made in the cost estimates for handling the cooling tower overflow in a separate corrosion resistant piping system. Previous studies indicate the aeration in the cooling tower requires the use of corrosion resistant materials for handling these water conditions.

3.4 Power Plant and Substation

The Power Plant section consists of a dual entry-pressure, condensing steam turbine designed for use in geothermal steam service, directly coupled to a generator. The turbine is provided with auxiliaries for operation at 3.5 in Hg exhaust pressure. The condenser is assumed to be of the direct contact low level type, including noncondensable gas removal equipment. The noncondensable gas is first cooled in a baffled section of the main steam condenser and then compressed by the first stage steam jet ejector. An intercondenser is provided to pre-cool the gas forwarded into the second stage steam jet ejector. After the second stage compression, the entire steam-gas stream is exhausted into a tall stack and then through a silencer (for noise abatement) into the atmosphere. The steam jet ejectors are sized to handle an assumed 1% wt. noncondensable gas content in the initial (high pressure) flash steam. Use of a tall stack assumes there is no pollution abatement equipment required.

The heat sink is assumed to be a conventional mechanical draft cooling tower designed for handling recirculating condensate made from geothermal steam. Condensate from the main condenser is pumped by canned type deep well centrifugal pumps operating at full vacuum suction and discharging to the upper water distribution header of the cooling tower. Conventional type centrifugal pump handles all auxiliary cooling water flows.

The downhole production well temperatures of 400° F, 450°F and 500°F assumed, were used to establish flash steam and turbine entry pressure conditions which would yield near optimum energy conversion from each initial well. These data are summarized in Table 3.1, Power Plant Cycle Data, along with conditions typical for a known vapor type steam resource. The calculations were extended for each case to obtain the variations in equipment cost.

The power plant is assumed to be housed in a building with typical maintenance work crane, electric auxiliary distribution sections and main control panels, electric switching disconnects, and transmission tie cable sections.

A step-up electric power transformer with switching for connection to a high voltage 230 kV transmission line is included.

TABLE 3.1

POWER PLANT CYCLE DATA

<u>Items</u>	<u>Liquid Resource</u>			<u>Vapor Resource</u>
Downhole Temperature °F	400	450	500	Steam Temp - 338
Well Flow - 10 ⁶ lb/hr	7.70	5.41	4.08	1.106
No Wells Required	10.25	7.25	5.50	7 - 9
Generation (Gross) MW	55	55	55	60
<u>Flash Steam:</u>				
High - psia	85	105	124	--
Low - psia	27	29	31	--
<u>Turbine Steam:</u>				
High Entry - psia	75	90	102	113.4
Flow - 10 ⁶ lb/hr	0.726	0.751	0.770	1.072
Low Entry - psia	20	23	25.7	--
Flow - 10 ⁶ lb/hr	0.517	0.399	0.314	--
<u>Total Turbine Flow</u> x 10 ⁶ lb/hr	1.243	1.150	1.084	1.072
<u>Jet Steam</u>				
Flow lb/hr	34,400	33,800	33,400	31,400
Heat Load - 10 ⁶ Btu/hr to Cooling Water Tower	1,240	1,150	1,079	1,006
Cooling Water Circ.-GPM	80,000	74,200	69,600	66,000
Wet Bulb °F	74	74	74	65

4.0

GEOHERMAL FACILITIES COST ESTIMATE

Cost estimates are presented for a flashed steam power plant, production and reinjection wells, and gathering and reinjection systems and facilities. As a comparison, estimated costs are also included for the Pacific Gas and Electric (PGandE) Unit No. 15 dry steam geothermal power plant and facilities at The Geysers.

4.1

Production and Reinjection Wells

The drilling costs of wells shown in Table 4.1 were provided by Occidental Exploration and Production Co. The given well drilling costs were in reasonable agreement with the estimated costs at The Geysers and therefore were also used for The Geysers dry steam field. Well cost estimates include top works assembly for pressure check and testing, and line tie connection point.

The well drilling schedule estimated for the hot water resource and The Geysers vapor resource is shown in Table 4.2. As the production from the hot water wells decays, additional wells are drilled. A sufficient number of production wells are drilled to provide the required steam flow to the plant at all times. In addition one extra production well is provided so that one well can be taken out of service without

TABLE 4.1

WELL, GATHERING AND REINJECTION FACILITY

CAPITAL COST ESTIMATE SUMMARY

WELL DRILLING COST:

DOLLARS (THOUSANDS)

Production Well (each)

\$750

Reinjection Well (each)

\$750

GATHERING AND REINJECTION FACILITIES:

<u>Initial Cost</u>	<u>Double Flash</u>			<u>Geysers Unit 15</u>
	<u>400°F</u>	<u>450°F</u>	<u>500°F</u>	
Gathering Facilities	\$2365	\$1838	\$1753	\$1895
Reinjection Facilities	2988	2455	2171	161
<u>Incremental Cost (per well)</u>				
Gathering Facilities	\$ 207	\$ 192	\$ 184	-
Reinjection Facilities	\$ 90	\$ 83	\$ 83	-

NOTE: All costs 1st Quarter 1977

TABLE 4.2

WELL DRILLING SCHEDULE

<u>Year</u>	<u>400°F</u>		<u>450°F</u>		<u>500°F</u>		<u>Geysers</u>	
	<u>P</u>	<u>R</u>	<u>P</u>	<u>R</u>	<u>P</u>	<u>R</u>	<u>P</u>	<u>R</u>
1	1	1	-		-		-	
2	2	2	2	1	1	1	1	1
3	4	2	3	2	2	1	4	1
4	4	3	3	2	3	2	4	1
5	3	1	2	1	2	1		
6	2		2		2			
7	2							
8			2		1			
9	2							
10			1					
11	1				1			
12			1					
13								
14	1							
15								
16					1			
17			1					
18								
19	1							
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								

NOTES:

Start electric power production from wells in 5th year

P - Production Well
R - ReInjection Well

decreasing the plant capacity. The hot water well flow decay curve used for determining the required well drilling schedule is shown in Figure 4.1. The curve is based on data obtained from recent hot water well tests. In all cases one spare reinjection well is drilled after the start of production. It was assumed that all the wells drilled were productive or could be used for reinjection and no costs have been included as "dry wells".

In the case of the dry steam resource at The Geysers, recent experience has shown that when sufficient well spacing is maintained (about one well per 20 acres) no appreciable decay occurs in the steam flow from the well. Therefore no additional wells are considered to be drilled after the initial plant start-up. The number of wells shown is the actual number drilled for PGandE Unit 15 at The Geysers field and include two spare production wells.

4.2

Gathering and Reinjection Facilities

The cost estimate for the steam gathering and reinjection facilities was made from the estimated cost of the individual components, such as valves, separators and piping. A summary of the installed cost for the initial facilities is

FIG 4.1 HOT WATER WELL FLOW DECAY VS. TIME.

shown in Table 4.1 for each resource under consideration. As the production from the hot water wells decays, additional wells are drilled and added to the gathering and reinjection system. The incremental cost of the gathering system and reinjection facilities required for each additional well were developed individually for each case and are also shown in Table 4.1.

4.3

Power Plant

The power plant cost estimates were developed using actual costs from previously built plants having 500 to 520°F bottom hole temperature and from current data supplied by major equipment manufacturers. Adjustments were made to the cost of the equipment based on the steam and cooling water flow requirements for 400°F, 450°F and 500°F bottom hole resource temperatures. All costs are adjusted to the first quarter of 1977.

Table 4.3 presents the summary of the estimated installed costs for the various flashed steam power plants and also shows the cost of PGandE Unit 15 at The Geysers.

The current (first quarter 1977) installed costs of the major equipment used in the development of the power plant cost estimate are shown below:

<u>Major Equipment Item</u>		<u>Dollars (Thousands)</u>		
Bottom Hole Temperature		400°F	450°F	500°F
1.	Turbine Generator			
	55 MW Gross	\$7263	\$6876	\$6622
2.	Condenser and Gas			
	Removal Equipment	1490	1412	1352
3.	Hot Well Pumps	1289	1242	1207
4.	Cooling Tower	1319	1215	1140

The breakdown of costs for the above major equipment is not presently available for The Geysers Unit 15 power plant.

TABLE 4.3

GEOHERMAL ELECTRIC POWER PLANTCAPITAL COST ESTIMATE SUMMARY

<u>FPC Account No.²</u>	<u>Electric Plant</u>	<u>Dollars (Thousands)</u>			
		<u>Double Flash¹</u>			<u>Geysers³ Unit 15</u>
		<u>400°F</u>	<u>450°F</u>	<u>500°F</u>	
311	Structures and Improvements	3,500	3,500	3,500	2,906
314	Turbine Generator Unit, Condenser, Cooling Tower, Pumps, etc.	13,290	12,670	12,260	10,571
315	Power Plant Electrical Equipment	1,240	1,240	1,240	1,027
316	Miscellaneous Power Plant Equipment	580	580	580	236
353	Substation Equipment	610	610	610	572
	Total Direct Cost	19,220	18,600	18,190	15,312
	Engineering and Construction Management	2,320	2,320	2,320	2,039
	Sub Total	21,540	20,920	20,510	17,351
	Contingency 10%	2,154	2,092	2,051	None
	Total Estimated Installed Cost ⁴	23,694	23,012	22,561	17,351

NOTES

¹Generating Unit is 55 Gross MW, Net Output 51.5 MW
Net Output at Bus 51.5 MW

²FPC Account Numbers include equipment in accordance with Federal Power
Commission Publication UNIFORM SYSTEMS OF ACCOUNTS PRESCRIBED FOR
PUBLIC UTILITIES AND LICENSEES FPC A-118

³Costs from PGandE application to the Public Utilities Commission.
Unit 15 is 60 Gross MW, Net Output 55 MW adjusted to 1977

⁴Costs are for First Quarter 1977

⁵Construction Period from experience is 24 months

5.0

COST OF POWER - GEOTHERMAL GENERATION

The economic analyses and the cost of power as developed in this Section uses the geothermal cost estimates of Section 4.0. The cost of power must consider many assumptions and elements which are presented along with the results, in this section.

5.1

Criteria and Assumptions

The assumptions involve timing, interest rates and escalations. Various combinations have been tested. The following general assumptions were used in the economic analyses:

- a. Project study period 34 years
- b. Start electric power generation in 5th year of project
- c. Project is financed with equity capital and no interest during construction is included.
- d. Federal and state income tax is assumed to total 51 percent of profit before taxes.
- e. Royalty payment of 10 percent is an expense before taxes and is assumed paid to the land owner and not a return to the project.
- f. Depletion is taken at 22 percent only for vapor (Geysers) resources. It is our understanding at this time the IRS has not ruled on depletion for liquid dominated resources. The studies use 0 depletion for liquid resources.
- g. Accounting depreciation for tax purposes for wells and production facilities is taken at 20 years straight line. For cases with power plant costs 30 years for geothermal plants straight line. Since land does not depreciate for tax purposes, this cost has not been included in the analysis.
- h. The IRS allows intangible drilling costs to be expensed for taxes in the year they are incurred. The percent of drilling or well costs assumed expensed for tax purposes is 30.

- i. The IRS allows tax losses for corporations to be carried forward for seven years. Therefore the analysis develops losses in first four years so the first years of electric power sales the income tax is reduced by the previous tax losses.

The criteria and assumptions are printed out for each set of cash flow calculations in section 5.2.

5.2

Cash Flow Analysis

The project cash flow and expenditures are presented by time period starting with initiation of well drilling. Commercial power production is assumed to start in the fifth year.

A computer program was used for the economic analysis and development of the project cash flow. Examples of the computer sheets are Sheet 1 and 2 following.

Sheet 1 is the input data sheet. The criteria and assumptions are printed out for the resource identified in the title. Then by project year the expenditures as defined below, are listed:

- a. EXP 1 is the well, gathering and reinjection system operation and maintenance expenses.
- b. EXP 2 is the power plant expenses if a power plant is included.
- c. WELLS is the total well drilling cost.
- d. SRF FACIL is the total gathering and reinjection system cost.
- e. PWR PLT is the total power plant cost if a power plant is in the particular analysis.

Sheet 2 is an example of the cash flow analysis for the case being studied.

ROGERS ENG S77006 == OXY EXP AND PROD ECON STUDY WL FL 750000 450F 1
 YEAR START GENERATION 5
 YEARS IN STUDY 34
 COST OF CAPITAL 0.0
 ROYALTY 0.100
 DEPLETION 0.0
 TAX ON INCOME 0.510
 GROSS REVENUE TAX 0.0
 EXPENSE OF WELL CAPITAL 0.300
 WELL LIFE 20.
 SURFACE FACILITIES LIFE 20.
 PLANT OUTPUT KW 51500.
 CAPACITY FACTOR 0.800

YR---EXP1-----EXP2-----WELLS-----SRF FACIL---PWR PLT

1	0.	0.	0.	0.	0.
2	0.	0.	2576021.	0.	0.
3	0.	0.	4593901.	0.	0.
4	0.	0.	4915469.	5627229.	0.
5	225810.	0.	3155730.	654989.	0.
6	241616.	0.	2251084.	576278.	0.
7	258529.	0.	0.	0.	0.
8	276626.	0.	2577262.	659779.	0.
9	276626.	0.	0.	0.	0.
10	276626.	0.	1288631.	329890.	0.
11	276626.	0.	0.	0.	0.
12	276626.	0.	1288631.	329890.	0.
13	276626.	0.	0.	0.	0.
14	276626.	0.	0.	0.	0.
15	276626.	0.	0.	0.	0.
16	276626.	0.	0.	0.	0.
17	276626.	0.	1288631.	329890.	0.
18	276626.	0.	0.	0.	0.
19	276626.	0.	0.	0.	0.
20	276626.	0.	0.	0.	0.
21	276626.	0.	0.	0.	0.
22	276626.	0.	0.	0.	0.
23	276626.	0.	0.	0.	0.
24	276626.	0.	0.	0.	0.
25	276626.	0.	0.	0.	0.
26	276626.	0.	0.	0.	0.
27	276626.	0.	0.	0.	0.
28	276626.	0.	0.	0.	0.
29	276626.	0.	0.	0.	0.
30	276626.	0.	0.	0.	0.
31	276626.	0.	0.	0.	0.
32	276626.	0.	0.	0.	0.
33	276626.	0.	0.	0.	0.
34	276626.	0.	0.	0.	0.

CASH FLOW TABLE

YEAR	CAPITAL	REVENUE	EXPENSE	ROYALTY	DEPRCTN	INTEREST	ACCUM CASH	AFT TAX	AVLBL	YEAR
				-DPLT GRT-		-UNRC CP-	REQMT	P OR L	FUNDS	
1	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
2	1803.	0.	773.	0.	90.	0.	2576.	-863.	-90.	2
3	3216.	0.	1378.	0.	251.	0.	7170.	-1629.	-251.	3
4	9068.	0.	1475.	0.	704.	0.	17713.	-2179.	-704.	4
5	2864.	2707.	1173.	271.	848.	0.	19313.	416.	1264.	5
6	2152.	5414.	917.	541.	955.	0.	17510.	3000.	3955.	6
7	0.	5414.	259.	541.	955.	0.	14122.	2433.	3388.	7
8	2464.	5414.	1050.	541.	1078.	0.	14163.	1345.	2423.	8
9	0.	5414.	277.	541.	1078.	0.	11361.	1723.	2802.	9
10	1232.	5414.	663.	541.	1140.	0.	9949.	1504.	2644.	10
11	0.	5414.	277.	541.	1140.	0.	7116.	1693.	2833.	11
12	1232.	5414.	663.	541.	1202.	0.	5672.	1474.	2675.	12
13	0.	5414.	277.	541.	1202.	0.	2808.	1663.	2865.	13
14	0.	5414.	277.	541.	1202.	0.	0.	1663.	2865.	14
15	0.	5414.	277.	541.	1202.	0.	0.	1663.	2865.	15
16	0.	5414.	277.	541.	1202.	0.	0.	1663.	2865.	16
17	1232.	5414.	663.	541.	1263.	0.	0.	1444.	2707.	17
18	0.	5414.	277.	541.	1263.	0.	0.	1633.	2896.	18
19	0.	5414.	277.	541.	1263.	0.	0.	1633.	2896.	19
20	0.	5414.	277.	541.	1263.	0.	0.	1633.	2896.	20
21	0.	5414.	277.	541.	1263.	0.	0.	1633.	2896.	21
22	0.	5414.	277.	541.	1263.	0.	0.	1633.	2896.	22
23	0.	5414.	277.	541.	1173.	0.	0.	1677.	2850.	23
24	0.	5414.	277.	541.	1012.	0.	0.	1756.	2768.	24
25	0.	5414.	277.	541.	559.	0.	0.	1978.	2537.	25
26	0.	5414.	277.	541.	416.	0.	0.	2048.	2464.	26
27	0.	5414.	277.	541.	308.	0.	0.	2101.	2409.	27
28	0.	5414.	277.	541.	308.	0.	0.	2101.	2409.	28
29	0.	5414.	277.	541.	185.	0.	0.	2161.	2346.	29
30	0.	5414.	277.	541.	185.	0.	0.	2161.	2346.	30
31	0.	5414.	277.	541.	123.	0.	0.	2192.	2315.	31
32	0.	5414.	277.	541.	123.	0.	0.	2192.	2315.	32
33	0.	5414.	277.	541.	62.	0.	0.	2222.	2283.	33
34	0.	5414.	277.	541.	62.	0.	0.	2222.	2283.	34

SHEET 2 of 2

CASE 1

PROJECT RATE OF RETURN 0.112

14553227.

0.015

The cash flow numbers are in thousands of dollars. The project rate of return on capital is calculated and printed at the bottom along with the project present worth sum and per unit sales revenue in dollars. The cash flow shows the capital revenue from sales, expenses from wells, well field and surface facilities operation and maintenance, royalty and depletion allowance (if applicable), depreciation, interest on unrecovered capital, accumulated unrecovered capital, after-tax profit or loss, and available funds generated from the project. The available funds are the sum of profit, depreciation and depletion. The available funds when positive are used to reduce the unrecovered capital until there is no more unrecovered capital.

The rate of return on the project is the percentage rate on the invested capital. The various cases and the capital included will be described to indicate the basis for the rate of return.

5.3 Geothermal Return on Investment

This study considers the economics of various geothermal electric power generation plants and is the primary objective of the report. The results of the various analyses have been plotted to show the relationships of the elements studied. The plots of the results are included in this section as identified below.

- 5.3.1 The wells, gathering and reinjection (areas 1 and 2 on Figure 2.1) are the initial considerations. The following cases are presented covering the capital involved in Area 1 and 2 for various resource conditions:

Base Case: uses 1977 costs with no escalation. The revenue per unit is the steam being sold based on the electrical output. See Figure 5.1

Case 1: uses escalation of 7 percent on all investment and operating costs for a period of eight years and then no escalation. The revenue per unit is sale price of steam. See Figure 5.2

5.3.2 Capacity Factor Cast: Since the revenue from the steam is based upon the kilowatthour output of the electric plant, a sensitivity analysis was made to show the change in return on investment (wells, gathering and reinjection system) with a change in plant output. Generation from an electric power plant is measured annually by capacity factor (CF). The capacity factor is the total energy output for the year divided by the product of maximum peak installed plant capacity and hours in a year. This sensitivity analysis is shown in the Capacity Factor Case. See Figure 5.3

5.3.3 Depletion Case: Resource depletion is a tax consideration which affects the return on investment (wells, gathering and reinjection system). A sensitivity analysis was done to show the change if depletion is allowed for taxes on a liquid resource. This is called the Depletion Case. See Figure 5.4

5.3.4 Case 2 expands the original subject and conditions of Case 1 to include the power plant construction cost as part of the capital and its operation and maintenances as project expenses. The revenue unit price plotted for this case is the necessary

FIGURE 5.3

CASE 2
(80% CF, ESCALATION)

FIGURE 5.5

electricity selling price to achieve the indicated rates of return. Hence, with the given electric sales prices the various returns are achievable when the wells, gathering and reinjection facilities, and power plant are all considered as a part of the investment. See Figure 5.5

5.4 Cost of Power

In electric utility cost analysis to get from capital costs of facilities to cost of power, capital charge rate multipliers are used in addition to fuel expenses and operation and maintenance costs.

5.4.1 The capital charge rate multiplier includes elements of fixed costs including capital recovery, income taxes, property taxes, insurance, and interim replacement in the case of geothermal interest during construction was not included in the EPC account items and therefore will be included as part of the capital charge rate.

TABLE 5.1

Capital Charge Rate Percentage

<u>Item</u>	<u>Geothermal</u>	<u>Nuclear</u>	<u>Coal</u>	<u>Oil</u>
Capital Recovery	9.734	9.464	9.464	9.464
Taxes	5.400	5.400	5.400	5.400
Insurance	0.250	0.250	0.250	0.250
Interim Replacment	0.350	0.350	0.350	0.350
Interest During Construction	<u>0.839</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	16.573	15.464	15.464	15.464

5.4.2 The operation and maintenance cost (excluding fuel cost) as a percent of capital, is developed from actual operating plant cost experienced by a utility. Since all the geothermal plants under consideration in this study are basically steam plants, the percent of capital has been assumed the same. The operation and maintenance annual cost as a percent of capital is 2.81 percent.

5.4.3 The cost of power for geothermal plant electric power generation as a percent of capital is the sum of fixed charges 16.573 and the operation and maintenance 2.81. The total percent is 19.38. The cost of power from a geothermal power plant is shown in Table 5.2 at 80 percent capacity factor for the resource conditions indicated.

TABLE 5.2

Electricity Cost Less Fuel
-Geothermal Power Plant

<u>Resource</u>	<u>1977</u> <u>Mills/kWh</u>	<u>1982</u> <u>Mills/kWh</u>
400°F	12.72	17.84
450°F	12.35	17.32
500°F	12.11	16.97
Vapor Geysers	9.31	13.00

5.4.4 In relation to the geothermal economic studies presented, the power plant cost of power as developed in section 5.4.3 must be added to the revenue per unit of the following case graphs: Base case, Case 1, Capacity Factor, and Depletion Cases. All of these cases show only steam sales price. When the power

plant cost of power is added the total cost of electricity generated from the given resource is obtained.

Example using Case 1:

<u>Resource</u>	<u>Steam Cost</u>	<u>Return on Investment</u>	<u>Electricity Selling Price</u>
400°F	20.0	11.5	32.72
450°F	20.0	15.0	32.35
500°F	20.0	18.2	32.11
Vapor	20.0	32.5	29.31

Investment in the example is that of Case 1.

Case 2 revenue unit cost as mentioned earlier is the selling price of electricity because the power plant cost is included as part of the project investment.

6.0

COST OF POWER-ALTERNATE GENERATION

Costs developed in this section have been compiled to provide comparative cost data of other types of electrical generation than geothermal and to provide information on present electric power load growth prognostications and trends in actual and planned construction of the various types of power generation plants, i.e., nuclear, coal and oil fueled. Information and data used has been obtained from surveys and reports available from such reliable trade literature as "Power Engineering", "Power", "Electrical World", etc., and government agency reports from Federal Power Commission (FPC), the Federal Energy Administration, and Electric Power Research Institute (EPRI).

6.1

General

FEA in their 1977 draft of "National Energy Outlook Executive Summary", are now projecting an annual growth rate of 5% for electrical generation from 1975 to 1985 compared to the historical rate of about 7 to 8 percent.

While all fuel costs are increasing, the change in relative fuel costs indicates that there will be more coal use and less use of oil and gas for electricity generation. FEA predicts that by 1987 the U.S. will generate 70% of its electricity from coal and nuclear power as compared to 50% in 1975. An independent survey of utility construction plans indicates that the commitments to new plant construction agree with FEA's prediction. See Tables 6.1 and 6.2.

COMMITTED GENERATING PLANTS 1976-1994

(POWER ENGINEERING/APRIL 1976)

	<u>Fossil</u> <u>No. of Plants</u>	<u>MW*</u>	<u>Nuclear</u> <u>No. of Plants</u>	<u>MW*</u>
1976	40	18,864	9	8,453
1977	34	15,845	11	10,348
1978	24	11,834	6	6,429
1979	33	16,882	12	11,353
1980	29	15,495	13	13,530
1981	21	11,981	17	16,910
1982	15	8,651	24	26,575
1983	15	8,502	19	21,124
1984	6	4,360	19	21,340
1985	3	2,070	18	18,536
1986	1	500	10	11,998
1987	2	1,650	7	8,110
1988	-	-	4	4,530
1989	-	-	4	4,930
1990	1	800	2	2,050
1991	1	800	-	-
1992	-	-	1	1,150
1993	1	800	-	-
1994	-	-	1	1,200
Indef.	14	10,871	14	16,076
TOTAL	240	129,905	191	203,487

*Does not include 3,626 MW of Combined cycle.

TABLE 6.1

TYPES OF FUELS FOR COMMITTED FOSSIL PLANTS

(POWER ENGINEERING/APRIL 1976)

<u>FUEL</u>	<u>NO. OF PLANTS</u>	<u>% OF PLANTS</u>
Coal	160	66.7
Oil	32	13.3
Gas	2	0.8
Lignite	16	6.7
Combination	30	12.5

TABLE 6.2

The FEA draft report indicates that coal and nuclear plants are competitive, in general, in electricity generating costs in most regions of the country and this is borne out by FPC reports from which capital and operating costs have been derived. (See Section 6.2) However, these costs are not entirely reflective of the present day increased costs of these plants to meet environmental and safety requirements and which are entirely apart from the expected inflation and fuel cost increases.

For example, environmental constraints on strip mining coal, and EPA requirements on SO₂, NO_x, and particulates emissions are certain to add costs to coal plants over costs of previous years. Electric Power Research Institute estimates that the addition of Scrubbing & Treatment facilities for SO₂ control only from stack gases adds \$100 - \$150/kW (approx. 20% of plant cost).

Similarly the public concern over environmental and safety aspects of nuclear energy production and reprocessing and disposal of nuclear wastes might limit the expected growth of nuclear facilities.

Recent technical reports confirm that utilities are continuing to hold back orders on nuclear facilities for several reasons which include: new lower estimates of load growth; an expected decrease in population growth; conservation efforts by consumers; more moderate growth of industry; and predominantly, the uncertainty over Administration policy relating to uranium availability, enrichment capacities, waste disposal considerations and firm licensing agreements.

The utility companies are in addition concerned at the wide discrepancies experienced between originally announced construction cost estimates vs. actual completed unit costs for nuclear plants.

Cost estimates of nuclear units at time of order vs actual finished cost or estimate as of Dec. 1975.

FIGURE

These wide discrepancies are in a good part due to stretch out of schedules from the aforementioned regulatory changes, and the delays due to indecisions.

EPRI have stated that for whatever reason capacity factors are what they are: better productivity could contribute more to the energy situation than anything else for at least a decade.

There is great incentive to reach such a goal of improved productivity. From a EPRI report:..."Assuming that about 200,000 MW of nuclear power capacity will be in operation by 1985, a 1% improvement in capacity factor can be equated to a decrease in oil demand of 26 million barrels a year or a reduction of an industry financing need for approximately three 1000 MW nuclear units at a cost approaching 3 billion - or - a reduction in coal demand of approximately eight million tons per year." Power Engineering April 1976.

A survey was made by Electrical World in April 1976 on new Fossil-Boiler Sales. The conclusion of this report is that all utilities buying Fossil-Fired boilers are now turning 100% to coal. This trend has been developing ever since the Arab oil embargo, in anticipation of national legislation that would make coal firing mandatory in utility boilers; in 1975 for the first time, no domestic boiler sale was made for any fuel other than coal. A few gas and oil fired boilers were still being delivered by the boiler manufacturers but for the most part, these were sold prior to 1974."

A comparison then of Cost of Power by Alternative Generation does not include gas fired generation facilities and only a complete comparison for oil costs for years 1967 and 1972 with only fuel costs estimated to 1977. Electrical World, in their 1974 steam station survey cost (Nov. 15, 1975), state that "Current trends indicate an early end to the building of gas-fueled generating units and a continuing swing from oil to coal. Here the investment cost of gas and oil burning stations is of little significance." From the same survey for all capacity plants reporting are typical fuel costs:

Coal	~	12.8 mills/kWhr
Gas	~	11.3 mills/kWhr
Nuclear	~	3.0 mills/kWhr

Fixed and Variable Costs

TYPE OF GENERATING FACILITY	Year			
	1967 ¹	1972 ¹	1974 ¹	1988
<u>NUCLEAR</u>				
Average Installed Capacity MW.	560 ²	668 ²	778 ²	950 ^{8 7}
Average Capacity Factor %	75 ¹	59 ¹	54 ^{5 6}	65
Capital Costs \$/kW	192	217	249 ⁶	1150 ¹⁰
Fixed Costs mills/kWhr	4.39 ³	6.50 ³	8.16 ³	31.3 ³
O & M (excl. Fuel) mills/kWhr	1.0	1.22	1.68	2.2
Fuel Costs "	1.95	1.99	3.53	4.7
Total Energy Costs "	7.34	9.71	13.37	38.2
Construction Time	6 - 6 12	6 1/2 - 7	8 - 10	11 - 12
<u>FOSSIL FUEL - COAL</u>				
Average Installed Capacity MW.	745 ²	732 ²	624.7 ²	950 ¹¹
Average Capacity Factor %	59.3	51	57.3	65
Capital Costs \$/kW	138	205.3	315.8	1050 ¹¹
Fixed Costs mills/kWhr	4.12	7.12	9.75	28.6
O & M (excl. Fuel) mills/kWhr	1.04	1.18	1.95	2.6
Fuel Costs "	2.95	4.48	3.45	4.6
Total Energy Costs "	8.11	12.78	15.15	35.8
Construction Time	4 - 5	4 - 5	5 - 7	7
<u>FOSSIL FULE - OIL</u>				
Average Installed Capacity MW.	542.5	713.7	9	9
Average Capacity Factor %	78	55	-	-
Capital Costs \$/kW	110	171.5	-	-
Fixed Costs Mills/kWhr	2.51	5.52	-	22.9 ¹³
O & M (excl. Fuel Costs) Mills kWhr	0.72	0.53	-	1.6 ¹²
Fuel Costs "	4.84	6.75	≈ 12.8	≈ 25.2 ¹²
Total Energy Costs "	8.07	12.80		49.7

TABLE 4

Notes

- ¹From FPC reported cost & operating data (in capacities 550 - 800 MW only for comparison purposes in this study) for plants in initial years of operation.
- ²Average or adjusted average if 2 unit plants are included
Typically adjusting 2 unit installations to equivalent cost of 1 unit.
Basis 65% of 2 unit cost for capital
 65% of 2 unit cost for O & M
 50% of 2 unit cost for fuel
- ³Based on an estimated 15.5% of capital costs. These costs include capital recovery, depreciation, insurance and taxes and interim replacements.
- ⁴No plants of the study capacities in 1967 burning predominantly oil. Used Canal Electric Co. Plant, Mass. initial year of operation 1968 for comparison purposes only.
- ⁵Not reported in last FPC 1973 Supplement.
- ⁶From Electrical World 19th Steam Station
Cost Survey - November 15, 1975 (See remarks in General).
- ⁷Estimated costs if orders for units placed in 1977.
- ⁸Extrapolated from Power Engineering April 1976 incremental increase in average size plant.
- ⁹No new orders for oil-fired boilers since 1974.
- ¹⁰Power Engineering April 1976 (page 85) states that for 1974-1975 equivalent new plant estimated costs increased 27%. If same rate of increase prevails nuclear plant price of \$562/kW for plants ordered in 1974 would increase to \$1150/kW $[(1.27)^3 \times \$562.]$ This compares with Estimates by Leonard F. C. Reichle in Public Utilities Fortnightly, February 3, 1977 of \$1,235 entitled "The Economics of Nuclear Power".

¹¹Investor Responsibility Research Center May 1975 Professional Engineering Magazine. Estimated construction cost in 1974 Coal plant initial year of plant operation in 1980 of \$638/kW. Add 10%/yr to 1974 estimate = $638 \times (1.10)^3 = \$849/\text{kW}$. This compares with Reichle's projection of \$870 without SO₂ removal. Adding \$200/kW for Cleanup Facilities = \$1050/kW

¹²Based on average heatrate of 10,000 Btus/net kWhr. Oil cost of \$14.50/bbl and 137,00 btus/gal in 1977

¹³Approximate fixed costs in 1988

6.3 Summary and Discussion of Estimate

In order to compare alternate energy costs on an equivalent basis, all plant costs were assembled as representative average costs for plants in the range of 560 - 800 MW. The reported costs from which these averages were derived contain many cost variables even in identical size plants, as may be expected. These variables can stem from the site location for land and site improvement costs, availability and source of cooling water, and variants on fuel storage and handling facilities. Reported costs used herein from FPC reports for new single unit are probably high because they usually include some embedded expenditures for future unit extensions.

Complete cost data for years 1967 to 1973 were taken from Federal Power Commission Annual Supplements on "Steam-Electric Plant Construction Cost and Annual Production Expenses". FPC-S-237, 238. 1974 FPC-S-239 has not yet been published. However, some limited interim data from FPC and trade publications was used to obtain 1974 costs.

The most comprehensive data for 1974 was taken from Electrical World November 15, 1976 - "19th Steam Station Cost Survey". Although that survey was not complete for all producing regions in the U.S., it generally covers new generating stations put in service during 1972,

1973 and the early part of 1974. It also includes older stations first operated in 1964 with new capacity added and completed in the survey period from 1972 to 1974. Operating data is for 1974 for a twelve month period.

Electrical World also points out in their survey that "it should be recognized that these figures were for construction that reached its peak spending in 1971. Cost increases since then have raised construction costs by at least 25%."

1988 plant costs were estimated from several sources and the construction costs shown are the best estimates of these costs in the first year of commercial operation, which are typically for nuclear plants 10 - 12 years, and for coal plants 7 years.

No attempt was made to estimate operating and maintenance and fuel costs to a comparable period, because of the present day volatile prices on fuels and the unknown escalation or inflation predictions for operations costs. However a nominal escalation from 1974 to 1977 was included for O & M and fuel costs.

The same installed capacity and capacity factors has been used for nuclear and coal plants. 950 MW is the appropriate size range of present day design of nuclear plants.

Investor Responsibility Research Center article (May 1975 Professional Engineer Table 1) indicates that nuclear plants, for the same percentage change in capacity factor are more sensitive to capital costs (mills/kWhr than coal fired plants, i.e. a change in capacity factor from 65 to 50 would vary nuclear costs from 21.3 to 27.7 mills/kWh vs. the same change would result in costs from 16.8 to 21.8 mills/kWh for coal.