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**AN ECONOMIC AND FINANCIAL EVALUATION OF
GEOPRESSURED—GEOTHERMAL RESOURCE
DEVELOPMENT**

Geopressured—Geothermal Technical Paper No. 2

July 1979

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**RPC, Inc.
Austin, Texas**

**U. S. DEPARTMENT OF ENERGY
Geothermal Energy**

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AN ECONOMIC AND FINANCIAL EVALUATION OF GEOPRESSURED-GEOTHERMAL RESOURCE DEVELOPMENT

The General Land Office of Texas
Bob Armstrong, Commissioner

RPC, Inc.
Austin, Texas

July 1979

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ABSTRACT

The purpose of the financial analysis was to provide the School Land Board and General Land Office of Texas with an analytical framework for analyzing the effect of leasing policies on the financial feasibility of geopressured-geothermal field development. Such an analytical framework was developed and was applied to eleven sets of development assumptions. The analytical framework, its applications, and results are discussed in this paper.

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This technical paper is one of a series of four papers in which the legal, financial, socioeconomic, and ecological aspects of geopressured-geothermal resource development on Public Free School Lands are discussed.

Many individuals contributed to the production of this paper. The project manager was Ann Orzech. Principal investigators were Ed Campbell and Alice Cheng. The technical editor was Nancy Grona; production assistance was provided by Kyle Pierce and Lori Snyder. The cover was designed by Kyle Pierce.

**Ronald T. Luke
President
RPC, Inc.**

1. INTRODUCTION

The purpose of the financial analysis is to provide the School Land Board (SLB) and the General Land Office of Texas (GLO) with an analytical framework for determining the effect of leasing policies on the financial feasibility of geopressured-geothermal field development. Such a framework must be based on consideration of characteristics of both the resource and the industries which are likely to develop and use the resource.

The geopressured-geothermal resource, as it is found along the Texas coast, will potentially yield two major components with economic significance. The first component is geothermal and geopressured energy. Among its primary uses is the generation of electrical power. The second likely component is some concentration of methane gas found in solution with the geopressured brine. Associated with resource development is the necessary provision for the environmentally safe disposal of produced brine.

Development and use of the resource will likely bring together two diverse industries. The technology for the discovery, development, and exploitation of the geothermal resource is indigenous to the energy industry, a large group of business concerns noted for their willingness to assume risk. Additionally, since a primary end product of the development is potentially the generation of electrical power, the utility industry may also become involved. By virtue of state and federal regulation, the conduct of that type of business places a firm under the utility classification, with the attendant aversion to risk characteristic of that industry.

The analytical framework which was developed for the financial evaluation of geopressured-geothermal resource development melds the dichotomous activities of resource exploitation and electric power generation, and it is applied to eleven sets of development assumptions. A discussion of the analytical framework, its applications, and results is presented in this paper.

Although the data and assumptions contained within the various analyses to be presented are the most reasonable that could be found, several caveats are in order. Considerable uncertainty presently exists regarding the characteristics of the reservoirs thought to contain geopressured-geothermal resources, together with dissolved methane, in commercially producible quantities. Furthermore, because there is not presently a field in production in Texas, cost estimates of the development and production phases are subject to wide error. Such estimates will be refined and revised as the resource itself is better defined and as production is actually undertaken. At that point, a financial analysis reflecting the revised information could be easily performed using the analytical framework developed as part of this study.

2. DISCUSSION OF ANALYTICAL FRAMEWORK

The analytical system was developed from the perspective of the field developer; specifically, it represents a tool for determining how changes in royalty rates and lease bonus payments will affect the field developer's after-tax rate of return. The system consists of three distinct computer models, as indicated in Figure 1. A detailed discussion of the relationships contained within this set of models is found in Appendix A.

The first model, the field development model, utilizes engineering and cost data as its primary inputs and provides scheduled capital investment and operating expense estimates, and production parameters to the two remaining models. The second model is the power plant model. It uses as inputs information from the field development model, such as power plant capacity, capital costs, and heat rate, as well as assumptions concerning financial and tax variables. Iterations of this program solve for the maximum price the power plant can pay for the brine. The brine price, in turn, determines that part of the revenue stream of the field developer originating from use of the heat content of the brine. As a result, both the price and the amount paid for the brine by the utility are data inputs to the third part of the system. Both of these models were created as part of this study using commercially available time-sharing systems.

The third model is a commercially available software package that was originally developed to provide a financial evaluation of oil and gas fields, and which was modified slightly for use for geothermal field evaluation. It receives as data inputs revenue from brine sales from the power plant model, cost schedules and production data from the field development model, and assumptions concerning natural gas prices and taxation and financial variables. The final output is a financial analysis of field development, including a calculation of revenues from methane sales and listings of detailed cash flows, net present value, payout period, and various rates of return. Most important in terms of this study, the model permits a sensitivity analysis of the after-tax rate of return to a range of royalty rates and lease bonuses.

Because the system was developed from the perspective of the field developer, its potential applications include its use by industry for a financial evaluation of a geopressured-geothermal venture. Sensitivity analyses similar to those performed in this study regarding royalty rates and lease bonus payments, for example, may be accomplished for a variety of variables.

Figure 1

FLOW DIAGRAM OF FINANCIAL ANALYSIS

3. MODEL SIMULATIONS

SCENARIO 1: BASE CASE

An initial working scenario or base case was developed utilizing detailed engineering data prepared for the Center For Energy Studies (CES), University of Texas at Austin, by Brown & Root, Inc. and Dow Chemical Company (Proceedings, Second Geopressured-Geothermal Energy Conference, Vol. IV, 1976). This case assumed disposal of the produced brine into geological formations above the producing zone but below fresh-water aquifers (shallow reinjection). It was generally assumed that the producing formations would be encountered at approximately 16,000 feet, but little other information concerning reservoir characteristics was considered. The life of the entire project after production was initiated was assumed to be 30 years, while the discovery, development, and construction phases were assumed to encompass 3 years.

Table 1 lists critical assumptions and data inputs to the field development model. Capital outlays for field development were scheduled in the following fashion. Drilling activities were assumed to produce one successful well in the initial period, with the remaining necessary source wells drilled throughout the following two years. Dry holes were converted to disposal wells as they were encountered, while the remaining needed disposal wells were assumed to be drilled in the third and final year of construction.

Capital outlays for the brine gathering and disposal system, together with the fuel (methane stripping) plant, were scheduled so that one-third of the value would fall in year two and the remainder the following year. The average length of brine-gathering and disposal-return pipelines were estimated to equal the radius of a circle inscribed with a square which contained the estimated area of the field.

Where possible, cost estimates were drawn from the previous work by Brown & Root, Inc. and Dow Chemical Company. Other information was gathered from discussion with industry sources. All costs were converted to and the analysis performed in terms of constant 1978 dollars. The system does have the capability, though, to perform the analysis given any assumed inflation rate.

Capital outlays for the electrical generating plant were assumed to be incurred entirely during year two, with construction extending through years two and three. While the model provides for a mix of equity and debt capital, it was assumed the project would be completely financed. This allows the interest rate on borrowed capital to be viewed as a weighted cost of capital to the investor. Power generated by this facility was assumed to be sold at a rate competitive with other new base-load

Table 1

DATA FOR THE FIELD DEVELOPMENT MODEL: BASE-CASE
SCENARIO ASSUMING DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE
(1978 Dollars)

<u>Variable</u>	<u>Estimated Value</u>
<u>Project Parameters</u>	
Total Brine Production (BPD)	432,000
Source Well Flow Rate (BPD)	40,000
Disposal Well Flow Rate (BPD)	20,000
Life of Production Well (Years)	30
Well Spacing (Miles)	0.5
Methane Content (SCF/BBL)	50
Probability of Drilling Success	50%
Power Plant Type	Single Flash
<u>Capital Costs</u>	
Source Well Drilling/Well	\$1,866,000
Source Well Completion/Well	832,000
Disposal Well Drilling/Well	690,000
Conversion of Dry to Disposal Well	575,000
Brine Gathering Pipeline/Mile	350,000
Disposal System Pipeline/Mile	175,000
Disposal Pump Cost/BPD Capacity	1.20
Fuel Plant Cost/BPD Capacity	21.00
Equipment for Pipeline Maintenance	250,000
Seismic/Geological/Geophysical	2,000,000
Power Plant/Megawatt Capacity	666,400
<u>Other Parameters</u>	
Tangible Fraction of Source Well Drilling Costs	40%
Operating Costs (Percent of Capital Cost)	7%
General and Administrative Costs (Percent of Capital Cost)	3%
Annual Workover Cost/Well	6,000
Power Cost for Disposal Pumps/KWH	.02
Power Required for Disposal (KWH/BPD)	.138
Power Plant Flow Rate/Megawatt Capacity (BPD)	17,280

generating plants. The target rate of return for the power plant was set at 15 percent, while unused investment tax credits were not carried through to after-tax net cash flow. Other assumptions of the base case power plant model are outlined in Table 2.

Building on the results of the first two models, information was fed into the resource financial evaluation model to provide a financial analysis of the field development. The salient assumptions and input parameters are shown in Table 3. Conversations with GLO staff indicated that the minimum lease payments presently accepted for oil and gas leases on Public Free School Lands (PFSL) are \$10 to \$25 per acre. It is anticipated that, until resource and reservoir characteristics are better defined, lease bonus payments per acre will not greatly exceed minimum amounts presently accepted for oil and gas leases. Thus, for the purpose of sensitivity analysis, lease bonus payments based on the acreage estimated by the field development model were varied between 10 and 50 dollars per acre. The minimum royalty rate presently accepted for oil and gas leases on PFSL is 20 percent. To encourage geopressed-geothermal development, though, the SLB has the authority to set a much lower, or even a zero, royalty rate. Therefore, for the purpose of sensitivity analysis, the royalty rate on revenues received from production of both the brine and methane was varied uniformly between 0 and 25 percent, with a 12.5 percent mean.

Appendix B presents the complete computer results of the base case simulation. The financial highlights may be summarized as follows:

Power Plant

1.	Maximum negative after-tax cash flow	\$ 948,000
2.	Present worth at a 10 percent discount rate	\$ 8,390
3.	Payout (years)	8
4.	After-tax discounted cash flow (D.C.F.) rate of return	14.80%

Field Development

1.	Maximum negative after-tax cash flow	\$36,235,696
2.	Present value at a 10 percent discount rate	\$50,357,072
3.	Payout (years)	8.61
4.	After-tax D.C.F. rate of return	17.41%

Table 2

DATA FOR THE POWER PLANT MODEL: BASE-CASE
SCENARIO ASSUMING DISPOSAL INTO FORMATION ABOVE THE PRODUCING ZONE
(1978 Dollars)

<u>Variable</u>	<u>Estimated Value</u>
<u>From F. D. Model Simulation</u>	25.0
Plant Capacity (Megawatts)	
Total Capital Cost	\$16,660,000
Annual Heat Consumption (Billion Btu)	6,500
Type of Plant	Single Flash
<u>Financial Parameters</u>	
Revenue (Cents/KWH)	4.5¢
Federal Income Tax Rate	48%
Investment Tax Credit	10%
Operating Costs (Percent of Capital Cost)	7%
General and Administrative Costs (Percent of Capital Cost)	3%
Ad Valorem Tax Rate/Hundred Dollars Valuation	4.2%
Electrical Generation Tax	.17%
Weighted Capital or Debt Cost	10.5%
Target Rate of Return	15%
Depreciable Life of Assets in Years (Straight Line Method)	30
<u>Other Parameters</u>	
Plant Availability	90%

Table 3

DATA FOR THE RESOURCE FINANCIAL EVALUATION MODEL:
BASE-CASE SCENARIO ASSUMING DISPOSAL INTO FORMATION ABOVE
THE PRODUCING ZONE
(1973 Dollars)

<u>Variable</u>	<u>Estimated Value</u>
<u>From F. D. Model Simulation</u>	
Thermal Value of Brine (BILBTU)	6,500 BILBTU
Annual Methane Production (MMCF)	7,884 MMCF
Annual General and Administrative Expenses	\$ 504,000
Annual Operating Costs	\$ 1,683,000
Tangible Investment (Scheduled)	\$46,489,000
Intangible Investment (Scheduled)	\$41,818,000
<u>From Power Plant Model Simulation</u>	
Price of Brine/MMBTU	\$.80
Price of Brine/BBL	3.31¢
<u>Financial Parameters</u>	
Federal Income Tax Rate	48%
Ad Valorem Tax Rate/Hundred Dollars Valuation	4.2%
Severance Tax on Methane	7.5%
Depletion Allowance (Brine and Methane)	15%
Investment Tax Credit	10%
Revenue for Methane/MCF	\$ 2.00
Annual Escalation on Gas Price	3.4%
<u>Parameters for Sensitivity Analysis</u>	
Lease Bonus Payment/Acre	\$ 10-50
Royalty Rate on Production	0-25%

OTHER SIMULATIONS

In addition to the base case scenario already described, ten other simulations were tested with the three model systems. Eight of these were variations on the base case. These are:

1. Reinjection of brine into producing formations
2. Redrilling half of producing wells every six years
3. Well spacing of five miles
4. Methane priced at the equivalent of fuel oil
5. Full use of Investment Tax Credit by field developer
6. Full use of Investment Tax Credit by both the field developer and the power plant operator
7. Five-year royalty holiday
8. Lease bonus payments substantially higher than assumed in other cases.

Each of these scenarios is discussed below. In addition, Table 4 summarizes these model simulations and highlights the sensitivity of after-tax rate of return to royalty rates and lease bonus payments. Assuming a royalty rate of 12.5 percent, the after-tax rate of return ranges from 7.5 percent to 21.4 percent. The lowest returns occurred in cases of wide well spacing and deep disposal of brine into the producing formation; the highest occurred under the assumptions either that methane be priced at the heating value equivalent of No. 2 fuel oil (formula used for pricing of natural gas supplies offered by Mexico) or that other operations of a nonutility power plant operator and the field developer be such that full use could be made of the Investment Tax Credit.

The remaining two cases were based on previous work done by Zinn for CES (Operations Research and Systems Analysis of Geothermal-Geopressed Resources in Texas--Final Report, 1977). As discussed in this study's main report, Zinn's production estimates represent optimistic production levels. Such levels, while useful for environmental impact identification, are less well suited for an analysis of the financial feasibility of a "typical" field and power plant facility.

Scenario 2: Deep Disposal Into the Producing Formation

This case takes into account the higher capital and operating costs associated with deep disposal of brine. Even though this mode of operation could enhance reservoir life, both capital and operating outlays are increased significantly. Drilling cost for a disposal well was estimated to escalate from the \$690,000 found in the base case, to match the \$1,866,000 outlay required for a source well. This difference is obviously attributable to the necessary depth of the well. Moreover, the capital cost of disposal pumps rose from \$518,000 to slightly less than \$8,000,000, while the power required for operation is an estimated 42 megawatts. This resulted in an increase in operating outlays of approximately \$7.5 million per year. Consequently, the rate of return (assuming 12.5 percent royalty rate) declined to 9.6 percent, while the

Table 4

FIELD DEVELOPMENT FINANCIAL ANALYSIS SCENARIO SUMMARIES

Scenario	Power Plant Rate of Return (%)	After Tax Rate of Return Sensitivity to Royalty Rate (%) (Lease Pmt. = \$30/Acre)				After Tax Rate of Return Sensitivity to Lease Payment (%) (Royalty Rate = 12.5%)			
		0%	12.5%	25%	Range	\$10	\$30	\$50	Range
1. Base Case	14.80	19.52	17.44	15.27	4.3	17.45	17.44	17.43	.02
2. Deep Disposal (into producing formation)	14.80	11.52	9.64	7.47	4.1	9.64	9.64	9.63	.01
3. Redrill Half of Wells Each 6 Years	14.80	17.17	15.01	12.79	4.4	15.02	15.01	15.0	.02
4. Well Spacing of 5 miles	14.80	8.83	7.45	5.97	2.9	7.66	7.56	7.45	.21
5. Fuel Oil - Gas Price Equivalent	14.80	23.90	21.42	18.85	5.1	21.43	21.42	21.41	.02
6. Full Use of ITC by Field Developer	14.80	19.84	17.71	15.50	4.3	17.72	17.71	17.70	.02
7. Full Use of ITC by Field and Power Plant Developer	22.57	23.94	21.38	18.73	5.2	21.39	21.38	21.37	.02
8. Royalty Holiday (5 year)	14.80	19.52	18.54	17.44	2.1	18.55	18.54	18.53	.02
		Lease Payment = \$525/Acre				\$250	\$525	\$800	
9. High Lease Payments	14.80	19.23	17.18	15.05	4.2	17.04	17.18	17.32	.28

NOTES:

Power plant capacity - 25 megawatt
 Power plant type - single flash
 Brine price per MMBTU = \$.80; per bbl = 3.31¢ except in Case 7 where price per MMBTU = \$1.74 and price per bbl = 4.14¢
 Power plant investment tax credit = 10% except in Case 7 where a 20% rate was assumed
 Initial natural gas price = \$2.00/MCF escalated at 3.4% annually except in Case 5 where a price of \$2.80 was assumed
 Field rate of production decline - none
 Field extent (Case 4) - 192,000 acres
 Field extent (all others) - 1,920 acres

maximum negative cash flow was boosted to approximately \$54.5 million and the payout stretched to slightly more than 14 years. However, at the assumed rate of natural gas production, net energy output from the project would remain positive, in the neighborhood of 200-250 megawatt hours of energy.

Scenario 3: Redrill Half of Wells Each Six Years

A major uncertainty associated with geothermal resource development concerns the potential life of producing wells. By assuming a significantly lower well life than in the base case, this scenario examines the effects of reduced well life and declining production on the financial feasibility of field development. In comparison with the base case, the after-tax rate of return assuming the mean cases of royalty and leasing provisions fell roughly 2.5 percent to 15.01 percent. The maximum negative cash flow was largely unaffected while the payout was stretched marginally to 8.76 years.

Scenario 4: Well Spacing of Five Miles

Wider well spacing would increase capital outlays for the transmission line and brine disposal systems. In addition, technological difficulties may be encountered in maintaining brine temperature over a long transmission-line distance. Higher capital outlays boosted the field development project cost to slightly more than \$109 million from roughly \$44 million in the base case. This scenario resulted in the lowest mean rate of return, 7.45 percent. The payout period was nearly doubled to 16 years, while the maximum negative cash flow climbed to more than \$80 million.

Scenario 5: Fuel Oil-Gas Price Equivalent

A higher price for methane associated with the geothermal brine was assumed in this case in order to determine the effect of natural gas prices on the financial feasibility of field development. As a proxy for an elevated price structure, the formula used for pricing natural gas supplies offered by Mexico was followed. That is, the price is based upon the heating value equivalent of imported No. 2 fuel oil. This scenario yielded one of the highest rates of return (21.4 percent, assuming mean royalty and lease provisions). In comparison with the base case, the maximum negative cash flow was unaffected while the payout was shortened by approximately one year.

These results highlight the sensitivity of the profitability of geopressured-geothermal field investment to the price of natural gas. This finding is consistent with prior work performed by CES and is important, in part, because of the classification of geopressured brine from wells spudded before 1990 as an alternative fuel under the Power Plant and Industrial Fuel Use Act (Federal Register, Vol. 44, No. 97). A special market might thus develop for alternative fuels as defined under the Act such that users of such fuels may be willing to pay a premium price. Such a price structure is

higher than that assumed even in this scenario and would seem to assure the field developer of profitable operations.

Scenario 6: Full Use of Investment Tax Credit By Field Developer

Although this case assumed the base-case operation of the power plant by a utility that could not utilize remaining investment tax credits elsewhere in their operations, it was assumed that the field developer/operator would have sufficient taxable income from other operations to fully utilize the investment tax credit generated by the geothermal production. The mean rate of return was increased a nominal 0.27 percent compared with the base case, and the maximum negative cash flow dipped modestly to \$33.6 million.

Scenario 7: Full Use of Investment Tax Credit By Field and Power Plant Developer/Operator

Provided that the electrical generating plant was not operated by a utility, current tax provisions designed to encourage geothermal development would allow the firm involved in this undertaking to realize, if possible, the use of a 20 percent investment tax credit for the power plant outlay. A higher target rate of return for the power plant, 22.5 percent, was chosen to provide a more attractive investment to a nonregulated firm. Assuming taxable revenues from other operations sufficient to avoid minimum payment provisions under current tax laws, a mean rate of return of nearly 21.4 percent would be experienced with payout in roughly 7.5 years.

Scenario 8: Five-Year Royalty Holiday

A "royalty holiday" represents a period of time during which the lessee is relieved of the obligation of tendering payment of a production royalty. The beginning of the holiday normally coincides with commencement of production. This scenario assumed a five-year royalty holiday in order to determine if such a royalty holiday would enhance the project rate of return, and thereby mitigate the risk associated with geothermal resource development.

Compared with the base-case scenario, the after-tax D.C.F. rate of return (assuming a royalty rate of 12.5 percent, lease payments of \$30 per acre, and continuous production) increased slightly to 18.54 percent, and the payout period decreased to about 7.9 years.

Scenario 9: Lease Bonus Payments Substantially Higher than Assumed in Other Cases

Bonus payments at the level assumed in the other scenarios proved to have a negligible financial impact. The mean bonus payment (\$525 per acre) equalled the

present value of the base case's royalty payments, assuming 12.5 percent royalty rate. Thus, lease bonus payments in this scenario ranged from \$250 to \$800 per acre.

The after-tax D.C.F. rate of return proved to be insensitive to even the higher level of bonus payments. The mean rate of return decreased only 0.26 percentage points (to 17.18 percent) and the payout period increased by 0.07 years (to 8.68 years), compared to the base case scenario.

A Review of Analysis Based Upon Scenarios by Zinn

The potential production descriptions, upon which the environmental analysis was based, were derived from analyses by Zinn (1977) under the aegis of the Center for Energy Studies, The University of Texas at Austin. Although the cases he presents for the Brazoria, Corpus Christi, and Matagorda Fairways provide maximum impact potential for certain environmental problems, several inconsistencies were encountered which rendered the work marginally useful for the purpose of financial analysis. In particular, the brine flow rate which was assumed to produce one megawatt of electrical energy was only 8,000 barrels per day, in contrast to the more than 17,000 barrel-per-day figure calculated by the Brown & Root study. This provided approximately 93 percent more electrical power from a system flow which fell nearly 12 percent short of that found in this financial analysis' base-case scenario. Additionally, the source well flow rate assumed for the Brazoria Fairway was a perhaps overly optimistic 128,000 barrels per day, and no provision was made for an additional well to maintain satisfactory system flow during workover operations.

However, using the cost estimates derived for the deep disposal adaptation of the base case, together with appropriate adjustments for power plant efficiency to reflect Zinn's more optimistic production, two potential development scenarios were nevertheless executed. The particular assumptions and financial results are summarized below.

The Brazoria Fairway

1. Assumptions:

Well spacing (miles)	5.86
Lease price per acre	\$17.50
Field extent (acres)	87,909
Power plant capacity (megawatts)	48.31
Annual natural gas production	7,054 MMCF

2. Financial Results:

After-tax D.C.F. rate of return	15.81%
Maximum negative cash flow (millions)	\$29.7
Payout (years)	9.25

Corpus Christi/Matagorda Fairways

1. Assumptions:

Well spacing (miles)	6.0
Lease price per acre	\$17.50
Field extent (acres)	230,400
Power plant capacity (megawatts)	12.30
Annual natural gas production	1,795 MMCF

2. Financial Results:

After-tax D.C.F. rate of return	0.0
Maximum negative cash flow (millions)	\$77.6
Payout (years)	--

As may be noted by the assumptions above, these scenarios are most closely likened to a combination of the base case with wide well spacing and deep reinjection. However, in the case of the Brazoria Fairway, for example, revenue from electrical power generation has been enhanced by a factor of almost two. The Corpus Christi/Matagorda Fairways, for which the data presented are identical, require far more extensive capital outlay for both drilling and the brine transmission system. These factors, together with the modest power and natural gas production, render the development unprofitable.

4. EFFECTS OF LEASING POLICIES

The simulations described above indicate that while the after-tax rate of return is more sensitive to capital costs and the expected price of methane, the rate of return is nevertheless influenced by one variable over which the SLB has some control, the royalty rate. On the average, a one percentage point change in the royalty rate resulted in a 0.17 percentage point change in the rate of return. Alternatively, the rate of return changes by one percentage point on average for every six percentage point change in the royalty rate. On the other hand, payments substantially greater than the minimum presently accepted for oil and gas leases have a negligible financial impact.

The effect of a five-year royalty holiday is to reduce the payout by a half year and to decrease the sensitivity of the rate of return to the royalty rate. More significantly, the higher the royalty rate, the greater the impact of a holiday on the rate of return. A five-year holiday assuming a royalty rate of 25 percent for the project's remaining life results in an increase in the rate of return from 15.3 percent in the base case to 17.4 percent; the same holiday assuming a subsequent royalty rate of 12.5 percent results in an increased rate of return from 17.4 percent in the base case to 18.5 percent.

Table 4 indicates that a five-year royalty holiday, followed by a 25 percent royalty rate, will yield about the same after-tax rate of return to the field developer as a 12.5 percent royalty rate with no royalty holiday. From the perspective of the field developer, the present values of the two royalty payment streams, discounted at the after-tax rate of return, are approximately equal, as shown in Table 5. A governmental unit, however, may use a lower interest rate to discount income streams to present value, because it operates in a different investment and borrowing climate than private industry. From the perspective of the SLB, then, the present value of royalties obtained assuming a five-year royalty holiday with a 25 percent royalty rate is approximately \$8.6 million greater than the present value of royalties obtained assuming a 12.5 percent royalty rate and no holiday, given a discount rate of ten percent.

It should be noted that it is unclear whether the royalty income foregone as a result of a royalty holiday would constitute a grant of public money as defined by Article 3, Section 51 of the Texas Constitution. This Article prohibits the giving or granting away of public money. The SLB has never granted a royalty holiday for oil and gas leases, and there is no case law on point. It is recommended that the SLB seek an Attorney General's opinion on this point before granting such a royalty holiday.

The present lack of experience and uncertainties associated with the geopressed-geothermal resource in Texas precluded recommendations concerning lease

Table 5

**PRESENT VALUES OF ROYALTY PAYMENTS,
BASE-CASE AND ROYALTY HOLIDAY SCENARIOS^a
(\$ Thousands)**

Year of Project	Discount Rate = After-Tax D.C.F. Rate of Return		Discount Rate = 10%	
	Base Case ^b	Royalty Holiday ^c	Base Case	Royalty Holiday
1	\$ 0	\$ 0	\$ 0	\$ 0
2	0	0	0	0
3	0	0	0	0
4	1,488	0	1,932	0
5	1,303	0	1,805	0
6	1,136	0	1,680	0
7	993	0	1,568	0
8	870	0	1,466	0
9	760	1,516	1,367	2,733
10	665	1,327	1,276	2,553
11	582	1,160	1,192	2,383
12	510	1,016	1,115	2,229
13	446	890	1,042	2,084
14	391	778	973	1,946
15	342	681	908	1,816
16	299	596	849	1,698
17	262	522	793	1,587
18	230	457	743	1,485
19	201	401	694	1,389
20	177	351	650	1,301
21	154	307	607	1,214
22	136	270	569	1,138
23	119	236	532	1,063
24	104	207	498	996
25	91	181	466	931
26	80	159	436	871
27	70	139	408	816
28	62	122	382	764
29	54	107	358	716
30	47	94	335	670
31	42	82	314	627
32	37	72	294	588
33	32	64	275	551
TOTAL ^d	\$11,682	\$11,737	\$25,526	\$34,151

^a Assumes royalty rates of 12.5 percent for Base Case Scenario and 25.0 percent for Royalty Holiday Scenario. Production is assumed to begin in year four.

^b After-Tax D.C.F. Rate of Return = 17.41%.

^c After-Tax D.C.F. Rate of Return = 17.44%.

^d Totals may not add due to rounding.

bonus versus royalty bidding. Competitive bidding for oil and gas leases on PFSL is most often done on the lease bonus payment rather than on the royalty rate. There are advantages and disadvantages to both bonus and royalty bidding. Bonus bidding results in a lump-sum front-end payment which is subsequently considered to be a sunk cost and thus does not affect subsequent exploration, development, and production decisions. The disadvantages of bonus bidding are that the lessee assumes the full burden of risk or uncertainty, and, further, that bonus bidding may result in substantial initial operator capital requirements. Royalty bidding results in a sharing of risk with the lessor and reduced capital requirements. In the case of geopressured-geothermal development, these advantages may encourage development, at least until developers have more experience with the resource. The major disadvantage of royalty bidding is that it may lead to early reservoir abandonment.

Likewise, no recommendations are made concerning the length of time appropriate for the primary lease term. The SLB is presently setting three-year primary lease terms for many leases on PFSL; the term on the federal Outer Continental Shelf is five years. Abuses of the primary term tend to be minimized in the case of bonus bidding; the operator who pays a substantial bonus has an incentive to drill quickly because of the capital costs associated with the bonus payment.

5. SUMMARY

While perhaps a greater body of knowledge remains unknown concerning the nature of Texas' geothermal-geopressured resource than is currently understood, this analysis has produced several notable findings. Assuming that development of the resource takes place along some combination of paths described in the scenarios above, the attractiveness of investment was found especially to depend upon the capital requirements and the expected price of methane. Thus, due to the capital intensive nature of geothermal resource development, any substantial delays encountered in the leasing or permitting processes would adversely affect the project's cash flow and would thereby diminish the project's financial attractiveness.

In addition, the royalty rate was found to influence the after-tax rate of return. Thus the SLB could enhance or retard the pace of development of this energy resource through the royalty provisions associated with geothermal leases on PFSL. A royalty holiday, for example, would increase the rate of return to the developer and would tend to mitigate the enormous risks associated in particular with the potential life of the producing wells.

Another variable which the SLB influences, lease bonus payments, was found to have a negligible financial impact, even at levels substantially higher than the minimum presently accepted for oil and gas leases.

The influence of royalty rates on the financial feasibility of field development, and the risks and uncertainties associated with geopressured-geothermal resource development, make the determination of royalty rates important if resource development is to be enhanced. The use of the financial models described in this paper, or similar techniques, to determine proper royalty rates and lease payments for specific tracts proposed for lease would ensure that, on the one hand, rates and payments are not so high such that resource development is discouraged, and, on the other hand, that terms are not so low as to preclude a fair return to the Permanent School Fund.

Appendix A

An Analytical Framework for the Economic and Financial Evaluation of Geopressured-Geothermal Resource Development

INTRODUCTION

The analytical framework is designed to fuse together the broadly divergent activities of resource exploration and electrical power generation. The system is divided into three computerized components, as shown in Figure 1 (page 4): (a) the field development model, which provides uniform data concerning a given production scenario; (2) the power plant model, which is a cash flow model of power plant construction and operation; and (3) a cash flow model analyzing resource discovery, development, and production.

Where possible, existing computer software has been utilized. Both the field development model and the power plant model were developed by RPC personnel using the Financial Modeling Language (FML) available from ADP Network Services, Cyphernetics Division. This software package offers modeling, analysis, and reporting capabilities employing more powerful commands than broad-based languages such as FORTRAN or COBOL. These include commands to perform sensitivity analysis, forward and backward "what-if" analysis, and Monte Carlo-based risk analysis.

The resource discovery and exploitation phase of geothermal development was examined by means of a modified version of the "U.S. Basic Petroleum Evaluation Package" offered by the Scientific Software Corporation of Denver, Colorado. This systematic analysis, widely utilized in the petroleum industry, provides a broad range of financial measures based upon the discounted cash flow of the venture. The capability for both sensitivity and risk analysis are also contained within this system.

FIELD DEVELOPMENT MODEL

DATA REQUIREMENTS

The field development model represents a time-efficient and uniform methodology for the calculation and scheduling of capital outlays. Data inputs include:

1. The flow rate for the entire project in barrels per day (bpd)
2. The expected flow rate per source well (bpd)
3. The expected injection rate (bpd) for disposal wells
4. Well spacing in miles
5. Expected well life in years
6. The fraction of source wells to be replaced periodically, based upon (5) above
7. Probability of drilling a successful source well
8. Capital outlays:
 - a. Drilling cost per source well
 - b. Completion cost per source well
 - c. Drilling cost per disposal well
 - d. The cost per well of converting dry source wells to disposal wells
 - e. Brine gathering pipeline cost per mile
 - f. Disposal pipeline cost per mile
 - g. Fuel plant outlays (per bpd of brine flow)
 - h. Disposal pump capital costs (per bpd of brine flow)
 - i. Initial exploration outlays - (geological/geophysical/seismic)

- j. The cost of outfitting a pipeline maintenance crew
- k. Generating plant capital outlays per megawatt
- 9. Methane content in cubic feet per barrel of brine
- 10. A mean estimated lease cost per acre
- 11. Estimated operating outlays:
 - a. Annual workover cost per well
 - b. The energy used (per bpd) to operate disposal pumps
 - c. The cost of energy used in (b) above
 - d. A factor to determine general and administrative expenses as a percentage of capital
 - e. A factor to determine other operating costs as a percentage of capital
- 12. The required brine flow (bpd) per megawatt of generated electricity
- 13. Heat utilization (BILBTU per megawatt capacity) for respective power plant designs
- 14. The tangible fraction of source well costs
- 15. The anticipated inflation rate to be utilized, if desired, to convert both capital and operating outlays into current dollars

MAJOR RELATIONSHIPS AND ASSUMPTIONS

Number of Wells Required

The total number of source wells needed for any given project to operate at full capacity was determined by the following formula.

$$(1) \quad TNSR = \frac{UNITS}{FLOW}$$

Where:

TNSR = the total number of source wells required

UNITS = the total system flow rate required (bpd)

FLOW = the anticipated production rate (bpd) per source well

The results of this equation were rounded arithmetically to eliminate fractional production. The total was arbitrarily increased to allow at least one well to be out of production for servicing or other work at any given time. The total number of disposal wells required was calculated in a similar fashion.

Field Size

The areal extent of the field required to support the project was estimated as follows:

$$(2) \quad \text{AREA} = (\text{SPACING})^2 (640)$$

$$(3) \quad \text{ACRES} = \text{AREA} (\text{TNSR})$$

Where:

AREA = an estimation of the areal extent required to support each well in acres

SPACING = well spacing in miles

ACRES = the field size in acres

While the above method of calculating the areal extent of a given field leaves much to be desired from a practical case-by-case standpoint, earlier work by Brown & Root followed similar logic. In practice, the placement of subsurface structures and fault lines would produce significantly altered results from the generalized equations.

Inflation Rate

If desired, both capital and operational outlays can be converted into current dollar expenditures. The logic followed for this operation throughout the model may be described by the following equation:

$$(4) \quad \text{VARIABLE} = \text{each capital and operating outlay}$$

INFL = the anticipated inflation rate per period

Investment Schedules

Tangible. Division of investment expenditures between tangible and intangible categories is necessary due to the differential tax treatment accorded certain outlays during the exploratory and developmental drilling process. Tangible assets are capitalized and amortized over the life of the producing property utilizing some predetermined schedule. On the other hand, intangible assets utilized in the drilling process are allowed by current tax law to be charged to expense as incurred.

Let $SWCTNF$ = the tangible fraction of source well costs

SWC = source well costs

KTS = transmission system capital outlays

KFP = fuel plant capital outlays

KDS = disposal system capital outlays

Then,

$$(5) \quad TANINV = SWCTNF (SWC) + KTS + KFP + KDS$$

Thus, the total of tangible assets is that fraction of source well costs that is tangible plus the cost of construction incurred during the period for the building of the transmission system, fuel plant, and disposal system.

$$(6) \quad SWC = NS (WDC) + NS (CC)$$

Where:

NS = the number of source wells needed

WDC = drilling costs per well

CC = the completion cost per successful well

The term WDC would, of course, be a function of the rather complex set of variables involved in cost determination for the drilling process. Of the following well cost determinants, items (5), (6), (7), (8), and (12) will likely create substantial deviation from normal oil/gas drilling experience due in part to the large pipe sizes to be required for the production of substantial volumes of geopressured-geothermal liquids, as well as problems of high pressure and corrosion.

Well cost determinants:

1. Site preparation (dredging, if necessary)

2. Move-in/move-out of rig and equipment
3. Rig up/rig down
4. Well depth
5. Penetration rate
6. Pipe costs
7. Mud costs
8. Cementing costs
9. Rig rate, including wages
10. Logging and testing
11. Disposal of tailings
12. Equipment costs (bits, etc.)
13. Supervision

The question of new accounting standards for oil and gas companies and whether they would be applied to geothermal development enters here. If the Financial Accounting Standards Board and the Securities and Exchange Commission prevail at some future date in their past attempts to require oil and gas producing companies to follow a "successful efforts" method of accounting, all exploration costs which are not directly related to the discovery of oil and gas reserves will be expensed during the period incurred. The "full-cost" method (generally followed by the industry) has considered that all costs of exploration and development were related to the oil and gas discovered and were therefore amortized on a unit of production basis as the reserves were produced. Implementation of the new standards would affect the timing of certain payments and project cash flow.

Other obvious tangible assets subject to depreciation schedules can be depicted by the following equations:

Let PLC = pipeline costs per mile

PLL = pipeline length in miles

Then,

$$(7) \quad KTS = PLC (PLL)$$

Let SDC = site development costs

PCS = processing system costs per unit of production

UNITS = production of brine in barrels

Then,

$$(8) \quad KFP = SDC + PSC (UNITS)$$

Let KDW = the capital costs of disposable wells

CPR = the capital costs of compressor units

BRL = the capital costs of the brine return lines

Then,

$$(9) \quad KDS = KDW + CPR + BRL$$

Where,

$$(10) \quad BRL = BPLC (BPLL)$$

When,

BPLC = the brine return line costs per mile

BPLL = the brine return line length in mile

and where,

$$(11) \quad KDW = (DCDW) (ND - NDC) + (CONVC) (NDC)$$

When,

DCDW = the drilling costs for disposal wells

ND = the number of disposal wells needed

NDC = the number of disposal wells converted from dry holes

CONVC = the costs of converting a dry hole to a disposal well

Intangible. The investment in intangible assets will be largely a function of those costs associated with the successful discovery and development of the resource which are judged to be intangible, together with the costs of drilling unsuccessful wells.

Let $(1 - \text{SWCTNF})$ = the intangible fraction of successful source well drilling costs

DRYHC = the costs of drilling a dry hole

Then,

$$(12) \quad \text{INTINV} = ((1 - \text{SWCTNF}) (\text{NS}) (\text{WDC})) + \text{DRYHC}$$

Where,

$$(13) \quad \text{DRYHC} = \frac{\text{NS} (1 - \text{PS})}{\text{PS}} (\text{WDC})$$

When,

NS = the number of source wells needed

PS = probability of drilling successful source well

Operating Costs

Operating costs for the geopressured-geothermal field and associated fuel (methane stripping) plant, together with disposal operations, may be described as follows:

Let GANDA = annual general and administrative expenses

PCGANDA = the percentage of capital outlays used to estimate annual general and administrative expenses

KKFP = the total fuel plant capital investment

KKTS = the total transmission system capital outlay

BBRL = the total capital outlay for disposal system piping

CCPR = the total capital outlay for disposal pumps

Then,

$$(14) \quad \text{GANDA} = \text{PCGANDA} (\text{KKFP} + \text{KKTS} + \text{BBRL} + \text{CCPR})$$

In estimating the annual operating outlays to maintain field production, special consideration was given to workover costs and the power consumption of brine disposal pumping units. These annual outlays were estimated utilizing the following equations:

Let DPWR = the cost of power necessary to operate the disposal pumps

WOC = the total workover cost for source wells

FOPCOST = other operating expenses as a percentage of capital

OPCOST = total annual operating expenses

Then,

$$(15) \quad \text{OPCOST} = \text{DPWR} + \text{WOC} + \text{FOPCOST}$$

Other computations performed by this particular model include the calculation of the energy needed to fuel the electrical generating plant, and the capital cost of the determined plant size. These figures, together with projected plant capacity in megawatts and the inflation rate, are transferred to the power plant model by means of a binary file linkage. The volume of methane recovered is also computed and used as an input to the financial analysis of field operation.

POWER PLANT MODEL

DATA REQUIREMENTS

The following data items are required inputs to the power plant model:

1. Total capital outlay
2. Total brine flow to plant (bpd)
3. Energy content of brine (billion Btu)
4. Plant capacity in megawatts
5. Anticipated inflation rate to be utilized, if desired, to convert both capital and operating outlays into current dollars
6. Plant availability in hours per year
7. Estimated operating outlays:
 - a. A factor to determine general and administrative expenses as a percentage of capital
 - b. A factor to determine other operating costs as a percentage of capital
 - c. Ad valorem tax rate applied to plant
 - d. Electrical utility tax rate
 - e. The equity fraction of capital cost of plant
 - f. The weighted cost of capital
8. Federal income taxes:
 - a. The marginal federal income tax rate
 - b. Allowable investment tax credit rate
9. Price per kilowatt hour (in cents) received for power generated by plant

10. The target internal rate of return

Data items (1) through (5) are either outputs or assumptions of the field development model.

MAJOR RELATIONSHIPS AND ASSUMPTIONS

The power plant model calculates a project's net cash flows, net present value, rate of return, and investment pay back period. Cash flows for each period during the life of the project are estimated using the following formula:

Let NCF = the net cash flow for the project during the period

PGRV = gross revenue from the power plant

KTPP = the total capital cost of the power plant during the period

PFTP = the federal tax payment due to operation of the plant

PEXP = expenses for plant operation, including depreciation

DEPRC = the depreciation charges attributable to the capital investment in the plant

Then,

$$(16) \quad NCF = PGRV - (KTPP + PFTP + (PEXP - DEPRC))$$

The above equation may be modified by a switch in the program which allows remaining unused investment tax credit to be added to the net cash flow of the respective period. This would be necessary in the event that a firm is assumed to have other income to which it could apply that remaining investment tax credit. This, of course, would yield the most favorable tax impacts created by the project.

The model provides for the calculation of a rate of return and present value based upon the net cash flows experienced during the life of the project. Additionally, the model was constructed so that a target rate of return would be met within 0.5 percent, with the fuel costs in either cents per barrel or dollars per million BTU computed as the dependent variable. This output is then fed into the financial analysis of the field development as a revenue stream.

Capital Investment

Total capital outlays for the plant could be characterized as follows:

$$(17) \quad KTPP = (KPK) (CAP)$$

When,

KPK = the capital cost per kilowatt of generating capacity

CAP = the capacity of the plant in kilowatts

Moreover,

$$(18) \quad KPK = f(\text{site preparation, system type, etc})$$

Revenues From Operations

Once the plant is placed in operation, contribution to cash flow would be made by the revenues gained from the sale of the generated power. This may be described as:

$$(19) \quad PGRV = (CAP) (AVOP) (PKWH)$$

Where,

CAP = total installed capacity in kilowatts

AVOP = the availability of the plant in hours per day

PKWH = the price per kilowatt-hour at the busbar

The determinations of the first two variables are contained in the production scenario assumptions. However, in the case of the price per kilowatt hour, information has been gained through the interview of major utility firms. Obviously, the price will have to fall near the limits expected with competing new base-load generating facilities and their anticipated costs of production at the time the proposed new plant comes on-line in order to be economically competitive.

Operating Expenses

The expenses associated with continued operation of a power plant are described below.

Let PGANDA = general and administrative expenses attendant to the operation of the power plant

POPCOST = the normal operating and maintenance costs of the plant

BTUC = the cost per thermal unit of brine
 PMT = the debt service or lease payment
 DEPRC = the depreciation charges attributable to the capital investment in the plant
 PADVTX = applicable ad valorem tax payments
 EURTX = electrical utility tax payments

Then,

$$(20) \quad PEXP = (PGANDA + POPCOST + BTUC + PMT + DEPRC + PADVTX + EURTX)$$

Where,

$$(21) \quad DEPRC = f(KTPP, PLIFE, PDEPCOD)$$

When,

PLIFE = the depreciable life of the capital assets
 PDEPCOD = the method of depreciation used on capital assets

Federal Tax Payments

Tax payments made by profit-making utility firms held by the public, generally the case of Texas utilities, would be determined by the following equations:

Let PFTP = the federal tax payment due upon income produced by operation of the power plant
 FTP = the tax payment due before calculation of the investment tax credit
 UFITRAT = the federal income tax rate for the utility firm
 PTXI = the taxable income produced by the power plant operation
 ITC = the investment tax credit applicable to power plant construction and operation

Then,

$$(22) \quad \text{FTP} = \text{UFITRAT}(\text{PTXI})$$

Where,

$$(23) \quad \text{PTXI} = (\text{PGRV} - \text{PEXP})$$

Then,

$$(24) \quad \text{PFTP} = (\text{FTP} - \text{ITC})$$

RESOURCE FINANCIAL EVALUATION MODEL

OVERVIEW

The "U.S. Basic Petroleum Evaluation Package" has been modified so that rather than the calculation and analysis of cash flows associated with the production of crude oil and natural gas, the program addresses production of geopressured-geothermal brine and natural gas. Prior to the financial analysis which would determine the project's desirability, as detailed as possible computation of the cash flow associated with the project must be accomplished. During each period of the forecast project life, cash flows may be expressed by the following equation:

- Let NCF = the net cash flow for the project during the period
- GRV = gross revenue from the resource development
- KRD = total capital expenditure for resource development
 during each period
- EXP = all expenses associated with production, including
 depreciation
- FTP = the federal tax payment
- ROY = the royalty rate on production
- DEPRC = the depreciation charges attributable to the capital
 investment

Then,

$$(25) \quad NCF = ((GRV)(1 - ROY)) - (KRD + FTP(EXP - DEPRC))$$

If in the case under scrutiny it is desired to apply unused investment tax credits generated from this particular project to offset other income of the firm, a switch in the program may be activated so that the surplus would be added to after-tax net cash flow. Moreover, the program provides numerous standard financial measures, including before and after-tax rate of return, discounted cash flow at various rates of discounting, present value after-tax profit on the investment, after-tax return on the investment, and the number of years to reach payout.

Input data to this section of the overall analytical system originates from three distinct streams. First, the field development model provides tangible and intangible

investment schedules stretching through the life of the project, operating and administrative expenses, and detailed information on production levels. Second, the power plant model simulation provides a specific value for revenue based upon the utilization of heat from the brine. The final group of data concerns the overt assumptions made concerning the operation and development of the field. These include various taxation and financial information, the anticipated price for natural gas with any escalation desired, together with assumptions concerning the input distributions for sensitivity analysis on royalty and lease bonus provisions.

To aid in the logical presentation, the following sections specify in greater detail the relationships within the model which apply to the various input factors.

MAJOR RELATIONSHIPS AND ASSUMPTIONS

Production Data

In the life of a project, revenues will begin to be generated once production has been initiated. However, if experience in oil and gas production is any indication, the level of output during successive periods of production from the initial one will decline at some rate. The user of the model may specify the rate of decline from among the following options:

1. Constant production; no decline
2. Exponential decline
3. Hyperbolic decline
4. Harmonic decline
5. Constant percentage decline

Revenues From Production

For the sum of outputs of the production process, gross revenues may be described as follows:

Let GRV = the gross revenue

UNITS = the level of production during the period

PRICE = the resource price during the period

Then,

$$(27) \quad GRV = (UNITS) (PRICE) \text{ or}$$

$$(28) \quad GRV = (PRGEO) (GEOP) + (GRGAS) (GASP)$$

Where,

PRGEO = brine production in thermal equivalents or barrels

GEOP = brine price per thermal equivalent or barrel

GRGAS = natural gas production

GASP = natural gas price

The market price received for the produced resource, be it geothermal brine or methane, will be subject to a number of variables. In either case, the price of available substitutes has a strong bearing. In any event, it is expected that the current dollar valuation of the price of energy will rise at some rate into the future. Therefore,

$$(29) \quad PRICE = (IPRICE) (1 + INFLP)$$

Where,

PRICE = the price received for the produced resource

IPRICE = the initial resource price

INFLP = the rate of escalation

Production Expenses

The operating expenses during the production period which are accrued in the process of supplying a given output may be described as follows:

Let GANDA = general and administrative expenses

OPCOST = operating costs for the entire project

ADVTAX = the ad valorem (property) tax on the capital investment

SEVTAX = the severance taxes on the recovered resources

INTINV = the investment in intangible assets

DEPRC = the depreciation charges against capital for the period

Then,

$$(30) \quad \text{EXP} = (\text{GANDA} + \text{OPCOST} + \text{ADVTAX} + \text{SEVTAX} + \text{INTINV} + \text{DEPRC})$$

Where,

$$(31) \quad \text{DEPRC} = f(\text{TANINV}, \text{DEPCOD}, \text{LIFE}, \text{SALVAG})$$

When,

TANINV = the investment in tangible assets

DEPCOD = the method of depreciation of tangible assets

LIFE = the depreciable life of the assets

SALVAG = the salvage value of the assets at the end of their depreciable life

Federal Tax Payments

Due to the risk inherent in the quest for oil and gas, federal income tax provisions have often been utilized to enhance the possible return from such investments and therefore ameliorate risk. Scheduled tax losses during the early, developmental years of a project are most often utilized to offset income from other sources. On a given project, such as the sort under analysis herein, federal taxes would be calculated as follows:

Let FTL = the initial federal tax liability

FITRAT = the federal income tax rate

TXI = the taxable income

Then,

$$(32) \quad \text{FTL} = \text{FITRAT}(\text{TXI})$$

The determination of taxable income in the case of resource-producing property is particularly complex. The following generally specified equation is rendered more specific in the assumptions associated with a particular scenario.

$$(33) \quad \text{FTP} = f(((\text{GRV})(1 - \text{ROY})), \text{EXP}, \text{DEPL}, \text{ITXCR}, \text{INVTAN}, \text{FTL})$$

Where,

GRV	=	gross revenues from production
ROY	=	the royalty rate on production
EXP	=	all expenses associated with production
DEPL	=	the rate of depletion allowance for the produced resources
ITXCR	=	the investment tax credit allowed for new tangible capital expenditures
TANINV	=	the investment in tangible capital expenditures
FTP	=	federal income taxes payable on operations

Appendix B
Base Case Model Simulations

FIELD DEVELOPMENT MODEL

A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 1	YEAR 2	YEAR 3
<hr/>			
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	12	0	0
TOTAL DRY HOLES DRILLED	12	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	11	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
<hr/>			
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	30	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
<hr/>			
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
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POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	0.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	0	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 0	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	0.00	20.21	20.21
BIL BTU USED-BINARY PWR PL	0	12,250	12,250
CAPITAL COST-BINARY	\$ 0	\$ 17,337	\$ 17,337
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NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	0	0	0
METHANE PROD.(MMCF/YR)	0	0	0
<hr/>			
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 0	\$ 0	\$ 0
TOTAL WORKOVER COST	0	0	0
OTHER OPRTG./MAINT. EXPENSES	0	0	0
OPERATIONAL EXPENSES	0	0	0
GEN. AND ADMIN. EXPENSES	0	0	0
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 1	YEAR 2	YEAR 3
	-----	-----	-----
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	1	6	5
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	2,698	16,188	13,490
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	11
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	1	6	5
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	575	3,450	10,465
	-----	-----	-----
TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 1,079	\$ 6,475	\$ 5,396
TOTAL DISPOSAL WELL COST	575	3,450	10,465
FUEL PLANT	0	3,024	6,048
TRANSMISSION SYSTEM	0	1,227	2,454
BRINE DISPOSAL LINES	0	1,176	2,352
DISPOSAL PUMPS	0	173	346
GEOLOGIC/SEISMIC COSTS	2,000	0	0
PIPELINER CREW EQPMT.	0	0	250
TOTAL TANGIBLE INVESTMENT	3,654	15,525	27,310
	-----	-----	-----
INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	1	6	5
DRY HOLE COST	\$ 1,866	\$ 11,196	\$ 9,330
INTAN. SUCCESSFUL WELL COST	1,619	9,713	8,094
TOTAL INTANGIBLE INVESTMENT	3,485	20,909	17,424
	-----	-----	-----
CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 1,079	\$ 7,554	\$ 12,950
TOTAL INV.-TRANS. SYS.	0	1,227	3,681
TOTAL INV.-FUEL PLANT	0	3,024	9,072
TOTAL INV.-DISPOSAL PUMPS	0	173	518
TOTAL INV.-DISPOSAL LINES	0	1,176	3,527
TOTAL INV.-DISP. WELLS	575	4,025	14,490
TOTAL CAPITAL INVESTMENT	1,654	17,179	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 4	YEAR 5	YEAR 6
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1979 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 4	YEAR 5	YEAR 6
<hr/>			
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
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TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 7	YEAR 8	YEAR 9
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 7	YEAR 8	YEAR 9

SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0

DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0

TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0

INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0

CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 10	YEAR 11	YEAR 12
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 10	YEAR 11	YEAR 12
<hr/>			
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
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TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 13	YEAR 14	YEAR 15
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 13	YEAR 14	YEAR 15
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SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
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TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 16	YEAR 17	YEAR 18
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/88L BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 16	YEAR 17	YEAR 18
<hr/>			
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
<hr/>			
TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 19	YEAR 20	YEAR 21
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 19	YEAR 20	YEAR 21
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 22	YEAR 23	YEAR 24
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 22	YEAR 23	YEAR 24
<hr/>			
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
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TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 25	YEAR 26	YEAR 27
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PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
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MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
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LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
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POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
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NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
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OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504
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**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 25	YEAR 26	YEAR 27
<hr/>			
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
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DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
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TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
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INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
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CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239
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OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
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(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 28	YEAR 29	YEAR 30
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
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(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 28	YEAR 29	YEAR 30

SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0

DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0

TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0

INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0

CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
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BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 31	YEAR 32	YEAR 33
PROJECT DESCRIPTION			
BRINE PRODUCTION(BBLS/DAY)	432,000	432,000	432,000
NUMBER OF SOURCE WELLS REQUIRED	12	12	12
SOURCE WELL FLOW RATE(BBLS/DAY)	40,000	40,000	40,000
TOTAL SOURCE WELLS DRILLED	0	0	0
TOTAL DRY HOLES DRILLED	0	0	0
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
DISP. WELL FLOW RATE (BBL/DAY)	20,000	20,000	20,000
TOTAL NR. CONVT. DISP. WELLS	12	12	12
TOTAL DISPOSAL WELLS DRILLED	0	0	0
TOTAL WELLS DRILLED FOR PROJECT	35	35	35
MAJOR ASSUMPTIONS			
LIFE OF PROD. WELLS IN YRS	0	0	0
FRACTION TO REDRILL	0.00	0.00	0.00
EXPECTED INFLATION RATE(%)	0.0	0.0	0.0
LEASE DATA			
WELL SPACING (MILES)	0.50	0.50	0.50
FIELD SIZE IN ACRES	1,920	1,920	1,920
LEASE PMT/ACRE (DOLLARS)	\$ 17.50	\$ 17.50	\$ 17.50
LEASE PAYMENT (YR. 1 ONLY)	33.6	33.6	33.6
POWER PLANT PARAMETERS			
GEN. CAPACITY (MWE)-SINGLE FLASH	25.00	25.00	25.00
BIL BTU USED-FLASH PWR PL	6,500	6,500	6,500
CAPITAL COST-SINGLE FLASH	\$ 16,660	\$ 16,660	\$ 16,660
GENERATING CAP.(MWE)-BINARY	20.21	20.21	20.21
BIL BTU USED-BINARY PWR PL	12,250	12,250	12,250
CAPITAL COST-BINARY	\$ 17,337	\$ 17,337	\$ 17,337
NATURAL GAS PRODUCTION			
SCF METHANE/BBL BRINE	50	50	50
METHANE PROD.(MCF/DAY)	21,600	21,600	21,600
METHANE PROD.(MMCF/YR)	7,884	7,884	7,884
OPERATIONAL OUTLAYS			
DISPOSAL PUMP POWER COST	\$ 435	\$ 435	\$ 435
TOTAL WORKOVER COST	72	72	72
OTHER OPRTG./MAINT. EXPENSES	1,176	1,176	1,176
OPERATIONAL EXPENSES	1,683	1,683	1,683
GEN. AND ADMIN. EXPENSES	504	504	504

**A MODEL FOR THE ESTIMATION OF CAPITAL AND OPERATIONAL
OUTLAYS FOR A GEOTHERMAL/GEOPRESSURED FIELD
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 31	YEAR 32	YEAR 33
SOURCE WELL COSTS			
NUMBER OF SOURCE WELLS DRILLED	0	0	0
DRILLING COST/WELL	\$ 1,866	\$ 1,866	\$ 1,866
COMPLETION COST/WELL	832	832	832
TOTAL SOURCE WELL COSTS	0	0	0
DISPOSAL WELL COSTS			
NUMBER OF DISPOSAL WELLS REQ'D	23	23	23
NUMBER OF DISPOSAL WELLS DRILLED	0	0	0
DISPOSAL WELL DRILLING COST/WELL	\$ 690	\$ 690	\$ 690
NUMBER OF CONVERTED DISP. WELLS	0	0	0
CONVERSION COST/WELL	\$ 575	\$ 575	\$ 575
TOTAL DISPOSAL WELL COST	0	0	0
TANGIBLE INVESTMENT			
TANGIBLE SOURCE WELL COST	\$ 0	\$ 0	\$ 0
TOTAL DISPOSAL WELL COST	0	0	0
FUEL PLANT	0	0	0
TRANSMISSION SYSTEM	0	0	0
BRINE DISPOSAL LINES	0	0	0
DISPOSAL PUMPS	0	0	0
GEOLOGIC/SEISMIC COSTS	0	0	0
PIPELINER CREW EQPMT.	0	0	0
TOTAL TANGIBLE INVESTMENT	0	0	0
INTANGIBLE INVESTMENT			
NUMBER OF DRY HOLES DRILLED	0	0	0
DRY HOLE COST	\$ 0	\$ 0	\$ 0
INTAN. SUCCESSFUL WELL COST	0	0	0
TOTAL INTANGIBLE INVESTMENT	0	0	0
CAPITAL INVESTMENT			
TOTAL DRILLING INV.	\$ 12,950	\$ 12,950	\$ 12,950
TOTAL INV.-TRANS. SYS.	3,681	3,681	3,681
TOTAL INV.-FUEL PLANT	9,072	9,072	9,072
TOTAL INV.-DISPOSAL PUMPS	518	518	518
TOTAL INV.-DISPOSAL LINES	3,527	3,527	3,527
TOTAL INV.-DISP. WELLS	14,490	14,490	14,490
TOTAL CAPITAL INVESTMENT	44,239	44,239	44,239

POWER PLANT MODEL

A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT BY RPC, INC.

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 2	YEAR 3	YEAR 4
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	0	0	666
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	0	0	7,884
PRICE PER KWH (CENTS)	0.00	0.00	4.50
GROSS REVENUE	0	0	8,870
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 0	\$ 0	\$ 500
OPERATING COSTS	0	0	1,166
DEPRECIATION EXPENSE	0	0	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	0	0	6,500
BRINE COST (CENTS/BBL)	0.00	0.00	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	0	0	5,218
BORROWED CAPITAL	16,660	0	0
INT. RATE ON BORROWED CAP.(%)	10.50	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	0	0	70
ELECTRICAL UTILITY TAX	0	0	15
TOTAL OPERATING EXPENSES	1,824	1,824	9,348
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 1,824)	(\$ 1,824)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 0	\$ 0	\$ 715
INVESTMENT TAX CREDIT RATE (%)	0.0	0.0	10.0
INVESTMENT TAX CREDIT	\$ 0	\$ 0	\$ 1,666
UNUSED INV. TAX CREDIT	0	0	1,666
FEDERAL TAX PAYMENT	(876)	(876)	(230)
CASH FLOW			
NET CASH INFLOW	\$ 0	\$ 0	\$ 8,870
NET CASH OUTFLOWS	948	948	8,563
NET CASH FLOW	(948)	(948)	306
CUMULATIVE NET CASH FLOW	(948)	(1,897)	(1,591)
PRESENT VALUE	\$ 8,390	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	14.80	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	8	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 5	YEAR 6	YEAR 7
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBLs/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
<hr/>			
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	(1,284)	(978)	(671)
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 8	YEAR 9	YEAR 10
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
<hr/>			
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	(365)	(58)	248
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 11	YEAR 12	YEAR 13
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBLs/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
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FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	554	861	1,167
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 14	YEAR 15	YEAR 16
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
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OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALJREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
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FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
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CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	1,474	1,780	2,086
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 17	YEAR 18	YEAR 19
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INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
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FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
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CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	2,393	2,699	3,006
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PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 20	YEAR 21	YEAR 22
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
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FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	3,312	3,619	3,925
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 23	YEAR 24	YEAR 25
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBLs/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
<hr/>			
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	4,231	4,538	4,844
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 26	YEAR 27	YEAR 28
<hr/>			
INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
<hr/>			
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
<hr/>			
CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	5,151	5,457	5,764
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)

	YEAR 29	YEAR 30	YEAR 31
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INVESTMENT			
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0	0
COST PER KW (DOLLARS)	666	666	666
<hr/>			
OPERATING REVENUE			
PLANT CAPACITY (MW)	25.00	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50	4.50
GROSS REVENUE	8,870	8,870	8,870
<hr/>			
OPERATING EXPENSES			
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166	1,166
DEPRECIATION EXPENSE	555	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218	5,218
BORROWED CAPITAL	0	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70	70
ELECTRICAL UTILITY TAX	15	15	15
TOTAL OPERATING EXPENSES	9,348	9,348	9,348
<hr/>			
FEDERAL TAXES			
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE (%)	10.0	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)	(230)
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CASH FLOW			
NET CASH INFLOW	\$ 8,870	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563	8,563
NET CASH FLOW	306	306	306
CUMULATIVE NET CASH FLOW	6,070	6,376	6,683
<hr/>			
PRESENT VALUE	\$ 0	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0	0

**A MODEL FOR THE ANALYSIS OF CASH FLOWS RESULTING FROM
THE CONSTRUCTION AND OPERATION OF A GEOTHERMAL POWER PLANT
BY RPC, INC.**

**(BASE CASE: A SCENARIO UTILIZING B AND R/DOW DATA ASSUMING)
(DISPOSAL INTO FORMATIONS ABOVE THE PRODUCING ZONE.)
(THOUSANDS OF 1978 DOLLARS UNLESS OTHERWISE NOTED)**

	YEAR 32	YEAR 33
	-----	-----
INVESTMENT		
TOTAL CAPITAL OUTLAY	\$ 16,660	\$ 16,660
EQUITY CAPITAL INVESTED	0	0
COST PER KW (DOLLARS)	666	666
	-----	-----
OPERATING REVENUE		
PLANT CAPACITY (MW)	25.00	25.00
AVAILABILITY OF PLANT(HRS/YR)	7,884	7,884
PRICE PER KWH (CENTS)	4.50	4.50
GROSS REVENUE	8,870	8,870
	-----	-----
OPERATING EXPENSES		
GENERAL AND ADMIN. COSTS	\$ 500	\$ 500
OPERATING COSTS	1,166	1,166
DEPRECIATION EXPENSE	555	555
BRINE FLOW (BBL/DAY)	432,000	432,000
ENERGY CONSUMED (BIL BTU)	6,500	6,500
BRINE COST (CENTS/BBL)	3.31	3.31
PRICE/MMBTU (DOLLARS)	\$ 0.80	\$ 0.80
FUEL COST	5,218	5,218
BORROWED CAPITAL	0	0
INT. RATE ON BORROWED CAP.(%)	0.00	0.00
DEBT SERVICE	\$ 1,824	\$ 1,824
AD VALOREM TAX	70	70
ELECTRICAL UTILITY TAX	15	15
TOTAL OPERATING EXPENSES	9,348	9,348
	-----	-----
FEDERAL TAXES		
INCOME BEFORE FED. TAXES	(\$ 479)	(\$ 479)
FEDERAL INCOME TAX RATE (%)	48.0	48.0
INCOME TAX PAYABLE	\$ 715	\$ 715
INVESTMENT TAX CREDIT RATE-(%)	10.0	10.0
INVESTMENT TAX CREDIT	\$ 1,666	\$ 1,666
UNUSED INV. TAX CREDIT	1,666	1,666
FEDERAL TAX PAYMENT	(230)	(230)
	-----	-----
CASH FLOW		
NET CASH INFLOW	\$ 8,870	\$ 8,870
NET CASH OUTFLOWS	8,563	8,563
NET CASH FLOW	306	306
CUMULATIVE NET CASH FLOW	6,989	7,296
	-----	-----
PRESENT VALUE	\$ 0	\$ 0
INTERNAL RATE OF RETURN (%)	0.00	0.00
INVEST. PAY BACK PERIOD (YRS)	0	0

SCIENTIFIC SOFTWARE
ECONOMIC EVALUATION

RUN DESCRIPTION

GEO. H. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

SINGLE-VALUED RESULTS TABLE

NPV OF PRE TAX C.F.AT DISC1 M\$	=	88722.708
PRSNT WRT AFT TAX CF (DISC1 M\$	=	50357.072
PRSNT WRT AFT TAX CF (DISC2 M\$	=	10627.551
PRSNT WRT AFT TAX CF (DISC3 M\$	=	-7844.831
PRSNT WRT AFT TAX CF (DISC4 M\$	=	-17340.421
BEFORE-TAX DCF RATE OF RETURN	=	19.20
AFTER-TAX DCF RATE OF RETURN	=	17.44
DISC PROFIT/INVST AT DISC1	=	.65
AFT TAX PROFIT/INVST (DECML)	=	4.90
AFT TAX RETRN ON INVST(DECML)	=	5.90
MAX. NEGATIVE CASH FLOW	=	-36325.696
PAYOUT (YEARS)	=	8.61
FIRST REVERSION POINT	=	0.0000

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

COLUMN TOTALS TABLE

• BRINE ENERGY BIL BTU	=	195000.000	•
• NET INTRSTBRINE ENRG BIL BTU	=	170625.000	•
• NET REVENU BRINE M\$	=	136500.000	•
• GROSS GAS MMCF	=	236519.985	•
• NET INTRST GAS MMCF	=	206954.987	•
• NET REVENU GAS M\$	=	774552.311	•
• TOTAL NET REVENUE M\$	=	911052.311	•
• INTANGIBLEDRILL COST M\$	=	41818.000	•
• OPERATING COST M\$	=	50490.000	•
• GENERL ANDADMNSTRATY M\$	=	16632.000	•
• LOCAL TAXES M\$	=	58474.065	•
• DEPRECIATN M\$	=	46489.000	•
• ALLOWABLE DEPLETION M\$	=	136657.847	•
• TOTAL DEDUCTIONS M\$	=	350560.912	•
• CAPITAL INVESTMENT M\$	=	88364.600	•
• PRE-TAX CASH FLOW M\$	=	697091.646	•
• FEDERAL INCOME TAX M\$	=	264386.972	•
• AFTER-TAX CASH FLOW M\$	=	432704.674	•
• PRSNT WRTHAFT TAX CF DISC1 M\$	=	50357.072	•

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

♦ SENSITIVITY ANALYSIS FOR AFTER-TAX DCF RATE OF RETURN ♦						
♦ RESULT VARIABLE... (RORATX) ♦						

♦ PROB	♦	MINIMUM	AVERAGE	MAXIMUM		♦
♦ VAR	♦	VALUE	VALUE	VALUE	MOST LIKELY	RANGE ♦

♦	♦					♦
♦ NI1	♦	15.269	17.440	19.524	17.440	4.3 ♦
♦ BONUS	♦	17.450	17.440	17.429	17.440	.0 ♦
♦	♦					♦

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	BRINE ENERGY BIL BTU	NET INTRST BRINE ENRG BIL BTU	ENERGY PRICE \$/MMBTU	NET REVENU BRINE M\$	GROSS GAS MMCF
1.00	0.000	0.000	.800	0.000	0.000
2.00	0.000	0.000	.800	0.000	0.000
3.00	0.000	0.000	.800	0.000	0.000
4.00	6500.000	5687.500	.800	4550.000	7883.999
5.00	6500.000	5687.500	.800	4550.000	7883.999
6.00	6500.000	5687.500	.800	4550.000	7883.999
7.00	6500.000	5687.500	.800	4550.000	7883.999
8.00	6500.000	5687.500	.800	4550.000	7883.999
9.00	6500.000	5687.500	.800	4550.000	7883.999
10.00	6500.000	5687.500	.800	4550.000	7883.999
11.00	6500.000	5687.500	.800	4550.000	7883.999
12.00	6500.000	5687.500	.800	4550.000	7883.999
13.00	6500.000	5687.500	.800	4550.000	7883.999
14.00	6500.000	5687.500	.800	4550.000	7883.999
15.00	6500.000	5687.500	.800	4550.000	7883.999
16.00	6500.000	5687.500	.800	4550.000	7883.999
17.00	6500.000	5687.500	.800	4550.000	7883.999
18.00	6500.000	5687.500	.800	4550.000	7883.999
19.00	6500.000	5687.500	.800	4550.000	7883.999
20.00	6500.000	5687.500	.800	4550.000	7883.999
21.00	6500.000	5687.500	.800	4550.000	7883.999
22.00	6500.000	5687.500	.800	4550.000	7883.999
23.00	6500.000	5687.500	.800	4550.000	7883.999
24.00	6500.000	5687.500	.800	4550.000	7883.999
25.00	6500.000	5687.500	.800	4550.000	7883.999
26.00	6500.000	5687.500	.800	4550.000	7883.999
27.00	6500.000	5687.500	.800	4550.000	7883.999
28.00	6500.000	5687.500	.800	4550.000	7883.999
29.00	6500.000	5687.500	.800	4550.000	7883.999
30.00	6500.000	5687.500	.800	4550.000	7883.999
31.00	6500.000	5687.500	.800	4550.000	7883.999
32.00	6500.000	5687.500	.800	4550.000	7883.999
33.00	6500.000	5687.500	.800	4550.000	7883.999
	195000.000	170625.000		136500.000	236519.985

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	NET INTRST GAS MMCF	EFFECT GAS PRICE \$/MCF	NET REVENU GAS M\$	TOTAL NET REVENUE M\$
1.00	0.000	2.00	0.000	0.000
2.00	0.000	2.07	0.000	0.000
3.00	0.000	2.14	0.000	0.000
4.00	6898.500	2.21	15252.683	19802.683
5.00	6898.500	2.29	15771.275	20321.275
6.00	6898.500	2.36	16307.498	20857.498
7.00	6898.500	2.44	16861.953	21411.953
8.00	6898.500	2.53	17435.259	21985.259
9.00	6898.500	2.61	18028.058	22578.058
10.00	6898.500	2.70	18641.012	23191.012
11.00	6898.500	2.79	19274.806	23824.806
12.00	6898.500	2.89	19930.150	24480.150
13.00	6898.500	2.99	20607.775	25157.775
14.00	6898.500	3.09	21308.439	25858.439
15.00	6898.500	3.19	22032.926	26582.926
16.00	6898.500	3.30	22782.046	27332.046
17.00	6898.500	3.41	23556.635	28106.635
18.00	6898.500	3.53	24357.561	28907.561
19.00	6898.500	3.65	25185.718	29735.718
20.00	6898.500	3.78	26042.032	30592.032
21.00	6898.500	3.90	26927.461	31477.461
22.00	6898.500	4.04	27842.995	32392.995
23.00	6898.500	4.17	28789.657	33339.657
24.00	6898.500	4.32	29768.505	34318.505
25.00	6898.500	4.46	30780.634	35330.634
26.00	6898.500	4.61	31827.176	36377.176
27.00	6898.500	4.77	32909.300	37459.300
28.00	6898.500	4.93	34028.216	38578.216
29.00	6898.500	5.10	35185.176	39735.176
30.00	6898.500	5.27	36381.471	40931.471
31.00	6898.500	5.45	37618.442	42168.442
32.00	6898.500	5.64	38897.469	43447.469
33.00	6898.500	5.83	40219.982	44769.982
	206954.987		774552.311	911052.311

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	INTANGIBLE DRILL COST M\$	OPERATING COST M\$	GENERAL AND ADMINSTRATV M\$	LOCAL TAXES M\$	DEPRECIATN M\$
1.00	3485.000	0.000	504.000	0.000	0.000
2.00	20909.000	0.000	504.000	0.000	121.800
3.00	17424.000	0.000	504.000	0.000	639.300
4.00	0.000	1683.000	504.000	1152.268	1549.633
5.00	0.000	1683.000	504.000	1191.381	1549.633
6.00	0.000	1683.000	504.000	1231.822	1549.633
7.00	0.000	1683.000	504.000	1273.639	1549.633
8.00	0.000	1683.000	504.000	1316.878	1549.633
9.00	0.000	1683.000	504.000	1361.587	1549.633
10.00	0.000	1683.000	504.000	1407.816	1549.633
11.00	0.000	1683.000	504.000	1455.617	1549.633
12.00	0.000	1683.000	504.000	1505.043	1549.633
13.00	0.000	1683.000	504.000	1556.149	1549.633
14.00	0.000	1683.000	504.000	1608.993	1549.633
15.00	0.000	1683.000	504.000	1663.634	1549.633
16.00	0.000	1683.000	504.000	1720.133	1549.633
17.00	0.000	1683.000	504.000	1778.552	1549.633
18.00	0.000	1683.000	504.000	1838.958	1549.633
19.00	0.000	1683.000	504.000	1901.418	1549.633
20.00	0.000	1683.000	504.000	1966.001	1549.633
21.00	0.000	1683.000	504.000	2032.780	1549.633
22.00	0.000	1683.000	504.000	2101.830	1549.633
23.00	0.000	1683.000	504.000	2173.227	1549.633
24.00	0.000	1683.000	504.000	2247.052	1549.633
25.00	0.000	1683.000	504.000	2323.386	1549.633
26.00	0.000	1683.000	504.000	2402.317	1549.633
27.00	0.000	1683.000	504.000	2483.930	1549.633
28.00	0.000	1683.000	504.000	2568.319	1549.633
29.00	0.000	1683.000	504.000	2655.577	1549.633
30.00	0.000	1683.000	504.000	2745.802	1549.633
31.00	0.000	1683.000	504.000	2839.094	1549.633
32.00	0.000	1683.000	504.000	2935.558	1427.833
33.00	0.000	1683.000	504.000	3035.302	910.333
	41818.000	50490.000	16632.000	58474.065	46489.000

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	ALLOWABLE DEPLETION M\$	TOTAL DEDUCTIONS M\$	TAXABLE INCOME M\$
1.00	0.000	3989.000	-3989.000
2.00	0.000	21534.800	-21534.800
3.00	0.000	18567.300	-18567.300
4.00	2970.402	7859.304	11943.379
5.00	3048.191	7976.205	12345.069
6.00	3128.625	8097.081	12760.417
7.00	3211.793	8222.066	13189.887
8.00	3297.789	8351.300	13633.959
9.00	3386.709	8484.929	14093.129
10.00	3478.652	8623.101	14567.911
11.00	3573.721	8765.971	15058.835
12.00	3672.022	8913.699	15566.451
13.00	3773.666	9066.449	16091.326
14.00	3878.766	9224.393	16634.047
15.00	3987.439	9387.707	17195.220
16.00	4099.807	9556.573	17775.473
17.00	4215.995	9731.181	18375.454
18.00	4336.134	9911.726	18995.835
19.00	4460.358	10098.409	19637.309
20.00	4588.805	10291.439	20300.593
21.00	4721.619	10491.033	20986.429
22.00	4858.949	10697.412	21695.583
23.00	5000.949	10910.809	22428.848
24.00	5147.776	11131.461	23187.044
25.00	5299.595	11359.615	23971.019
26.00	5456.576	11595.526	24781.650
27.00	5618.895	11839.459	25619.841
28.00	5786.732	12091.685	26486.531
29.00	5960.276	12352.487	27382.689
30.00	6139.721	12622.156	28309.316
31.00	6325.266	12900.993	29267.448
32.00	6517.120	13067.512	30379.957
33.00	6715.497	12848.133	31921.850
	136657.847	350560.912	

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	NET REVENUE M\$	OPERATING COSTS M\$	GENERAL AND ADMINSTRATV M\$	LOCAL TAXES M\$	CAPITAL INVESTMENT M\$
1.00	0.000	0.000	504.000	0.000	7196.600
2.00	0.000	0.000	504.000	0.000	36434.000
3.00	0.000	0.000	504.000	0.000	44734.000
4.00	19802.683	1683.000	504.000	1152.268	0.000
5.00	20321.275	1683.000	504.000	1191.381	0.000
6.00	20857.498	1683.000	504.000	1231.822	0.000
7.00	21411.953	1683.000	504.000	1273.639	0.000
8.00	21985.259	1683.000	504.000	1316.878	0.000
9.00	22578.058	1683.000	504.000	1361.587	0.000
10.00	23191.012	1683.000	504.000	1407.816	0.000
11.00	23824.806	1683.000	504.000	1455.617	0.000
12.00	24480.150	1683.000	504.000	1505.043	0.000
13.00	25157.775	1683.000	504.000	1556.149	0.000
14.00	25858.439	1683.000	504.000	1608.993	0.000
15.00	26582.926	1683.000	504.000	1663.634	0.000
16.00	27332.046	1683.000	504.000	1720.133	0.000
17.00	28106.635	1683.000	504.000	1778.552	0.000
18.00	28907.561	1683.000	504.000	1838.958	0.000
19.00	29735.718	1683.000	504.000	1901.418	0.000
20.00	30592.032	1683.000	504.000	1966.001	0.000
21.00	31477.461	1683.000	504.000	2032.780	0.000
22.00	32392.995	1683.000	504.000	2101.830	0.000
23.00	33339.657	1683.000	504.000	2173.227	0.000
24.00	34318.505	1683.000	504.000	2247.052	0.000
25.00	35330.634	1683.000	504.000	2323.386	0.000
26.00	36377.176	1683.000	504.000	2402.317	0.000
27.00	37459.300	1683.000	504.000	2483.930	0.000
28.00	38578.216	1683.000	504.000	2568.319	0.000
29.00	39735.176	1683.000	504.000	2655.577	0.000
30.00	40931.471	1683.000	504.000	2745.802	0.000
31.00	42168.442	1683.000	504.000	2839.094	0.000
32.00	43447.469	1683.000	504.000	2935.558	0.000
33.00	44769.982	1683.000	504.000	3035.302	0.000
					88364.600

RPC - GEOTHERMAL FINANCIAL ANALYSIS MODEL

GEOTH. RESOURCE ANALYSIS-BASE CASE BY RPC, INC.

YEAR	PRE-TAX CASH FLOW M\$	FEDERAL INCOME TAX M\$	AFTER-TAX CASH FLOW M\$	PRSENT WORTH AFT TAX CF DISC1 M\$
1.00	-7700.600	-1914.720	-5785.880	-5785.880
2.00	-36938.000	-10336.704	-26601.296	-24182.996
3.00	-45238.000	-8912.304	-36325.696	-30021.236
4.00	16463.415	2853.911	13609.504	10225.022
5.00	16942.894	4155.644	12787.250	8733.864
6.00	17438.675	6125.000	11313.675	7024.902
7.00	17951.313	6331.146	11620.168	6559.282
8.00	18481.381	6544.300	11937.081	6125.610
9.00	19029.471	6764.702	12264.769	5721.605
10.00	19596.196	6992.597	12603.599	5345.156
11.00	20182.189	7228.241	12953.949	4994.308
12.00	20788.107	7471.897	13316.210	4667.251
13.00	21414.626	7723.836	13690.789	4362.307
14.00	22062.446	7984.342	14078.103	4077.925
15.00	22732.292	8253.705	14478.586	3812.664
16.00	23424.913	8532.227	14892.686	3565.191
17.00	24141.083	8820.218	15320.865	3334.267
18.00	24881.603	9118.001	15763.602	3118.745
19.00	25647.300	9425.908	16221.392	2917.560
20.00	26439.031	9744.285	16694.747	2729.724
21.00	27257.681	10073.486	17184.195	2554.321
22.00	28104.165	10413.880	17690.286	2390.498
23.00	28979.430	10765.847	18213.583	2237.465
24.00	29884.454	11129.781	18754.672	2094.487
25.00	30820.248	11506.089	19314.159	1960.882
26.00	31787.859	11895.192	19892.668	1836.014
27.00	32788.370	12297.524	20490.846	1719.294
28.00	33822.897	12713.535	21109.362	1610.173
29.00	34892.599	13143.691	21748.908	1508.142
30.00	35998.670	13588.472	22410.198	1412.726
31.00	37142.348	14048.375	23093.973	1323.482
32.00	38324.910	14582.379	23742.531	1236.955
33.00	39547.680	15322.488	24225.193	1147.364
	697091.646	264386.972	432704.674	50357.072

LIST OF ABBREVIATIONS

BBL - barrels

BILBTU - billion British thermal units

BPD - barrels per day

CES - Center for Energy Studies, The University of Texas at Austin

GLO - General Land Office of Texas

ITC - Investment Tax Credit

KWH - kilowatt hour

MCF - thousand cubic feet

MMBTU - million British thermal units

MMCF - million cubic feet

PFSL - Public Free School Land (state of Texas)

SCF - standard cubic feet

SLB - School Land Board of Texas

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