DOE/ET/27231--T1

REVISED 3/81

Direct Application of West Coast Geothermal Resources In a Wet-Corn-Milling Plant

Final Report

June, 1980

Prepared by
Burns and Roe Industrial Services Corporation
and
Corn Products
for

U.S. Department of Energy

Under Contract No. DE-AC03-79ET27231

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

Burns and Roe **Industrial Services Corporation**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DOE/ET/27231--T1

DE82 008524

DOE/ET/27231--T1

DIRECT APPLICATION
of
WEST COAST GEOTHERMAL RESOURCES
in a
WET-CORN-MILLING PLANT

NOTICE

FINAL REPORT

June 1980

(Revised: March 1981)

PORTIONS OF THIS REPORT ARE ILLEGIBLE. I
has been reproduced from the best available
copy to permit the broadest possible avail-
ability.

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Burns and Roe Industrial Services Corporation
Paramus, New Jersey

Corn Products, a Unit of CPC International, Inc.

Prepared for

U.S. Department of Energy
Under Contract No. DE-AC03-79ET27231

Rev. 3/81

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

gth

DIRECT APPLICATION
of
WEST COAST GEOTHERMAL RESOURCES
in a
WET CORN MILLING PLANT

TABLE of CONTENTS

<u>Section Number and Title</u>	<u>Page</u>
Table of Contents	i
List of Figures	ii
List of Tables	iii
I - Summary	I-1
II - Conclusions	II-1
III - Introduction	III-1
A. General	III-1
B. Study Objectives	III-1
C. Work Scope	III-2
IV - Geothermal Resource Assessment	IV-1
A. Imperial Valley/East Mesa Program	IV-1
B. Geothermal Reservoir Design Data	IV-5
C. Institutional Factors	IV-15
V. Description of Base Plant	V-1
A. Process Description	V-1
B. Energy Utilization	V-6
VI - Geothermal Brine Application	VI-1
A. Geothermal Supply System	VI-1
1. Geothermal Well	VI-1
2. Downhole Production Well Pump	VI-4
3. Geothermal Brine Chemistry and Treatment	VI-5
4. Injection Pump	VI-7
B. Case I - Geothermal Surface System Conceptual Design	VI-8
1. Process Description	VI-8
2. Piping and Equipment	VI-10
3. Energy Utilization	VI-18
C. Case II - Combined Geothermal/Cogeneration Surface System Conceptual Design	VI-22
1. Process Description	VI-22
2. Piping and Equipment	VI-24
3. Energy Utilization	VI-38
VII - Operating Cost Estimates and Economic Analysis	VII-1
A. General Approach	VII-1
B. Sensitivity Analysis	VII-12
C. Results of Analysis	VII-14
VIII - References	VIII-1

LIST of FIGURES

<u>Fig. No.</u>	<u>Title</u>	<u>Page</u>
IV-1	Southern California General Area Map	IV-2
IV-2	East Mesa KGRA Lease Units	IV-3
IV-3	Map of USBR Leaseholds at East Mesa	IV-4
IV-4	Temperature Contours (⁰ F) at 2000 ft. Depth for East Mesa KGRA	IV-8
IV-5	Temperature Contours (⁰ F) at 3000 ft. Depth for East Mesa KGRA	IV-8
IV-6	Temperature Contours (⁰ F) at 4000 ft. Depth for East Mesa KGRA	IV-9
IV-7	Temperature Contours (⁰ F) at 5000 ft. Depth for East Mesa KGRA	IV-9
IV-8	Temperature Contours (⁰ F) at 6000 ft. Depth for East Mesa KGRA	IV-10
IV-9	Temperature Contours (⁰ F) at 7000 ft. Depth for East Mesa KGRA	IV-10
IV-10	East Mesa Field	IV-11
IV-11	Administrative Requirements for Development of Geothermal Resources on Federal Land	IV-19
V-1	Corn Product Overall Process Flow Diagram	V-2
V-2	Base Plant Steam and Natural Gas Distribution System	V-7
VI-1	Well Costs versus Depth	VI-3
VI-2	Geothermal System Conceptual Design - Case I	VI-9
VI-3	Geothermal System Conceptual Design Plot Plan - Case I	VI-11
VI-4	Geothermal Brine Production Wellhead Piping Diagram	VI-12
VI-5	Geothermal Brine ReInjection Wellhead Piping Diagram	VI-13
VI-6	Geothermal System Piping Diagram - Main Plant Area	VI-14
VI-7	Combined Geothermal/Cogeneration System Conceptual Design - Case II	VI-23
VI-8	Combined Geothermal/Cogeneration System Conceptual Design Plot Plan - Case II	VI-25
VI-9	Geothermal Brine Production Wellhead Piping Diagram	VI-27
VI-10	Geothermal Brine ReInjection Wellhead Piping Diagram	VI-28
VI-11	Combined Geothermal/Cogeneration System Conceptual Design Piping Diagram - Main Plant Area	VI-29
VI-12	Steam Generation Piping Diagram	VI-30
VII-1	After Tax Rate of Return and Payback for Case I, Case II and Case III	VII-16
VII-2	After Tax Rate of Return and Payback for Case I	VII-17
VII-3	After Tax Rate of Return and Payback for Case II	VII-18
VII-4	After Tax Rate of Return and Payback for Case III	VII-19

LIST of TABLES

<u>Table No.</u>	<u>Title</u>	<u>Page</u>
I-1	Energy Utilization Comparison	I-10
I-2	Operating Costs and Economic Analysis Parameters - "Best Estimates"	I-11
IV-1	East Mesa KGRA Wells - Geothermal Characteristics	IV-6
IV-2	East Mesa Geothermal Brine Chemistry	IV-7
IV-3	Some California State Agencies That Are Concerned With Geothermal Resources Development	IV-20
VI-1	East Mesa Geothermal Brine Chemistry	VI-6
VI-2	Piping List - Case I	VI-19
VI-3	Major Equipment List - Case I	VI-20
VI-4	Piping List - Case II	VI-36
VI-5	Major Equipment List - Case II	VI-37
VII-1	Major Equipment Included in Capital Cost Estimates	VII-5
VII-2	Operating Data	VII-13
VII-3	Estimate of Intangible Drilling Costs	VII-15

I. SUMMARY

INTRODUCTION

Burns and Roe Industrial Services Corporation, in conjunction with Corn Products, a Unit of CPC International, conducted a study of the direct application of geothermal energy to a hypothetical new wet corn milling plant in East Mesa, California.

The current study was intended to evaluate the engineering and economic feasibility of utilizing the geothermal resources in East Mesa, California in a new corn processing plant. Institutional barriers were also identified and evaluated.

The study was sponsored by the U.S. Department of Energy under Contract No. DE-AC03-79ET27231.

APPROACH

Based on available literature and conversations with other investigators, estimates were made of typical geothermal resources in the East Mesa area that would be applicable to the current study. The following is a partial list of the data that was used:

Well Flow Capacity = up to 350 gpm

Wellhead Temperature = 335⁰F

Well Drawdown = 500 feet at 230 gpm

Wellhead Pressure = 100 psig (shut in)

Production Well Depth = 6000 feet

Reinjection Well Depth = 3000 feet

An exact location for the Corn Milling Plant within the East Mesa KGRA was not established. Review of the various temperature contour maps for the area indicated that an assumed wellhead temperature of 335⁰F would be reasonable. However, it is not known whether any lease units are available for lease, sublease, or sale which would give mineral rights to a resource of the quality and quantity assumed here. Obviously, any reductions in wellhead temperature or flow would have an adverse effect on the rates of return and payback periods reported later in this document.

Typical process data for a wet corn milling plant were compiled by CPC. The data were primarily related to steam and natural gas utilization.

The extent of the process details provided in this report was determined, to a large degree, by CPC confidentiality requirements. More detailed data than presented in this report have been made available by CPC, but publication of the detailed data was precluded by confidentiality considerations.

Using CPC's process information, several alternative plant designs which utilized geothermal energy were developed. Then a capital cost estimate and rate of return type of economic was performed to evaluate each alternative. This report describes the results and conclusions of all these efforts.

BASE PLANT PROCESS DESCRIPTION

Wet corn milling plants produce a variety of products, the principle ones being corn oil, corn syrup, corn starch and animal feed.

The overall wet corn milling process is shown in Figure V-1.* Wet milling of corn is a continuous process with all parts run as an integrated whole. No one product can be produced unless the corn grinding, finishing, and by-products departments are running at the same time.

The wet milling process consists of several distinct parts: (1) the separation process, which divides and isolates the components of the corn kernel to obtain starch as the principal end product and steepwater, oil, and feeds as by-products; (2) the hydrolysis process which converts some of the starch to syrup or dextrose; and (3) the starch modification process which changes its characteristics by physical or chemical treatment.

*Note: Some figures and tables from other sections have been reproduced in this Summary for convenience.

The scrubbed odorous gases from the gluten, germ, starch and feed dryers for the proposed plant, have to be oxidized at 1750°F in an incinerator to satisfy California EPA regulations for odor control. About 73 million Btus/hr of waste heat from the incinerator is used to generate, 64,066 lbs/hr of 150 psig saturated steam in the heat recovery unit. The amount of steam generated in the waste heat recovery unit is sufficient to supply the steam requirement for the whole plant.

CASE I - GEOTHERMAL SYSTEM CONCEPTUAL DESIGN DESCRIPTION

Due to the large amounts of waste heat made available, the need to incinerate the waste gas stream at 1750°F seriously limited the amount of natural gas which could be displaced by the relatively low temperature geothermal energy source. Preliminary investigations indicated that, within the current state-of-the-art, there were no other suitable processes available to eliminate the odor producing contaminants. Therefore, the following changes to the base plant design were explored to utilize geothermal energy: 1) preheat the odorous waste gas stream before it entered the incinerator; 2) preheat the dry air entering the starch dryer; and 3) preheat the softened makeup water entering the deaerator. The electrically driven (950 hp) steepwater mechanical vapor compression unit was replaced by a quadruple effect evaporator, heated by 150 psig saturated steam, which was made available due to geothermal preheating of both the dry air entering the starch dryer and the makeup water to the deaerator.

Figure VI-2 shows the flow sheet for Case I. An intermediate flow loop is provided to protect against contamination of products or deaerator water by geothermal fluid if heat exchanger leaks should occur.

The total amount of geothermal brine required at 335°F was 232 gpm, of which 59 gpm preheated the odorous waste gases entering the incinerator. The dry air to the starch dryer and waste gases to the incinerator were heated up to 295°F and 300°F, respectively, and the softened makeup water to the deaerator was heated up to 214°F.

Since the geothermal fluid was not concentrated in this concept, threshold treatment at 5 ppm was the pretreatment used to prevent calcium carbonate, calcium sulfate and barium sulfate scaling. The geothermal brine reinjection temperature was 200°F which was high enough to prevent silica precipitation.

CASE II - COMBINED GEOTHERMAL/COGENERATION SYSTEM CONCEPTUAL DESIGN

DESCRIPTION

The second concept considered involved the use of a portion of waste heat from the waste gas incinerator to generate electricity in a back pressure steam turbine. The turbine exhausted to process at 150 psig. The flow sheet for this system is shown in Figure VI-7. Geothermal energy was used in the process to replace that portion of the waste heat which was used to generate electricity in lieu of process steam. No additional natural gas was burned to produce the electricity. In addition to the steam turbine/generator cycle, the other differences between Cases I and II were as follows:

- (a) The heat recovery unit design was revised so that it would produce 56,934 lb/hr of 850 psig/825°F steam in lieu of 64,044 lb/hr of 150 psig saturated steam.

- (b) Steam from the heat recovery unit was routed to the straight, non-condensing steam turbine which exhausted to the process at 150 psig.
- (c) The 7,100 lb/hr reduction in steam flow to the process was accommodated by using geothermal energy to heat the steepwater evaporator. Approximately 2,000 lb/hr of steam would have still been available to the evaporator, however, it was judged more economical to heat the evaporator entirely by geothermal energy and divert the 2,000 lb/hr to do additional preheating of the starch dryer, thereby further decreasing the fuel consumption of that unit.
- (d) The higher steam drum pressures on the heat recovery unit increased the blowdown heat recovery to the extent that geothermal heating was eliminated.

In Case II, a total of 320 gpm of geothermal brine at 335°F was required, of which 59 gpm preheated the waste gas to the incinerator. The heat in the remainder of the brine was distributed almost equally to the starch dryer and the steepwater evaporator via the intermediate flow loop. The brine reinjection temperature was again 200°F.

ENERGY UTILIZATION

Table I-1 summarizes and compares the energy utilization for each of the three cases described above. The total energy required is somewhat higher for the geothermal system due to additional pumping requirements, heat losses from the geothermal system, because the thermal steepwater evaporator requires more energy to operate than the mechanical unit used in the base plant, and because steam used in the steepwater evaporator is not returned, thereby increasing makeup water heating requirements. However, consistent with national goals, the use of

geothermal energy still permits a reduction in energy required from conventional sources, (i.e. natural gas and electrical energy). Based on Table I-1, these reductions would be 6.6% for Case I and 17.1% for Case II where the cogeneration system also makes a significant contribution.

COST ESTIMATES and ECONOMIC ANALYSIS

Detailed capital cost estimates were made for the base case, Case I and Case II based on 1st quarter 1980 dollars. These estimates are included in the Appendix.

The production and reinjection well costs were based on order of magnitude estimates received from various sources, which exhibited a considerable range. The well costs used in this analysis assume that exploration costs have been incurred previously and would not be chargeable to the project.

Also, no resource charge was assessed against the geothermal systems to cover the costs of obtaining the mineral rights to a resource of the quality assumed in this study. However, the economic analysis was performed for a $\pm$ 25 percent range in capital cost. Therefore, the impact of the cost incurred to purchase these rights can be assessed in terms of reduced rate of return or increased payback periods.

For the base plant, cost estimates were made only for equipment which would be modified or eliminated in the other cases so that incremental costs could be determined for use in the economic analysis. From the "best estimates" contained in the Appendix, the incremental costs were \$1,902,000 for Case I and \$2,622,000 for Case II. For purposes of the economic analysis, these costs were increased by 5% for escalation from the 1st quarter to the 4th quarter of 1980, which was the assumed purchase date for the equipment.

In order to evaluate the economics of each case, a discount cash flow rate of return (ROR) type of analysis was performed and payback periods were determined for each case. Table I-2 shows the "best estimates" of operating costs and other parameters which were assumed for the economic analysis. After completing this analysis, some

sensitivity analysis were performed to assess how the conclusions might be affected if certain parameters such as capital cost and fuel oil escalation varied from the "best estimates".

In order to assess the relative contributions of the geothermal system and the cogeneration system to the rate of return for Case II, more approximate cost estimates were also developed for the addition of the cogeneration system only to the base plant. This arrangement was called Case III. The cogeneration system was basically the same as that used for Case II except for the assumption that more natural gas would be burned in the incinerator so that the quantity of high pressure steam produced would match the base plant 150 psig process steam production of 64,044 lb/hr.

The cost estimates for Case III were conservatively approximated based on comparisons between Cases I and II. The incremental capital cost for Case III relative to the base case was \$720,000 (1st quarter, 1980 dollars). Also, it was calculated that relative to the base plant, the Case III plant would consume 169 cfm more natural gas and would have to purchase 2,318 kWh/hr less electrical energy.

The results of the economic analysis for the operating costs on Table I-2 (i.e. the "best estimates") are shown for Cases I, II and III on Figure VII-1. For the "best estimates" (i.e. for an abscissa value of 1.0 on the curves), the after tax ROR and payback periods were 28% and 3.8 years, respectively, for Case I. The corresponding values for Case II were 46.1% and 2.2 years. Since the ROR and payback period for Case III are nearly equal to those for Case II, it was concluded that the return on the investment in the geothermal portion of the Case II plant was also about 45%. Thus, a synergistic effect is obtained when geothermal and cogeneration systems are combined in a process of this type.

Figures VII-2, VII-3 and VII-4 show the results of studies done to assess the effect of escalation rates on the results.

CONCLUSIONS

1 - The maximum payback period considered acceptable for energy projects by most industrial firms ranges from 36 years. If a wet corn

system would be well within this acceptable range. This conclusion applies for a range of escalation rates which could be reasonably expected over the assumed 20 year plant life. In fact, the combined geothermal/cogeneration system would be well within the acceptable range even if current day prices existed for the life of the plant, that is for zero escalation.

2 - The need to incinerate odorous waste gases at high temperatures severely limits the amount of natural gas that can be displaced by geothermal. However, 6.4% and 7.1% of the fuel and electricity requirements, respectively, could be displaced by the addition of a geothermal system only. If a combined geothermal/cogeneration system were added, 9% of the fuel and 33.6% of the purchased electricity requirements could be displaced.

3 - There is a synergistic effect when the geothermal and cogeneration systems are combined (Case II) because the later utilizes some of the incinerator waste heat to produce electricity, thereby leaving some additional process heating which can be accomplished geothermally. This, of course, assumes that the additional geothermal energy can be obtained from the same well as was used for the Case I arrangement (i.e. geothermal only), that is, by simply pumping more water from the same well.

4 - Assuming that there is an adequate market within 100-200 miles of East Mesa, there appears to be no institutional constraint that would preclude the construction of a geothermal plant. However, it appears that the procedures required to obtain the leases and rights to use the resource may be somewhat time consuming and could lead to delays.

Table I-1 Energy Utilization Comparison, 10⁶ Btu/hr

	<u>Base Case</u>	<u>Case I Geothermal</u>	<u>Case II Geothermal/Cogeneration</u>
Natural Gas - Incinerator	80.26	76.23	76.23
- Starch Dryer	6.38	4.83	2.62
- Total	86.64	81.06	78.85
% Reduction	(Base)	(6.4%)	(9.0%)
Purchased Electrical Energy	25.60 (7500 kW)	23.77 (6965 kW)	17.00 (4980 kW)
% Reduction	(Base)	(7.1%)	(33.6%)
Subtotal - Conventional Sources	112.24	104.83	95.85
Utility Power Plant Energy Loss*	17.10	15.92	11.39
Total - Conventional Sources	129.34	120.75	107.24
% Reduction	(Base)	(6.6%)	(17.1%)
Geothermal Energy	0.00	14.67	20.44
Total Energy Removed from Surroundings	129.34	135.42	127.68

*Loss associated with generation of purchased electrical power assuming 33% plant thermal efficiency.

Table I-2 - Operating Costs and Economic Analysis Parameters - "Best Estimates"

<u>Date</u>	<u>End of Project Year</u>	<u>Natural Gas Cost \$/MBtu</u>	<u>Electricity Cost \$/kWh</u>
1/1/80		3.80	0.0376
6/1/81	0		
6/1/82	1	20%/yr	15%/yr
6/1/83	2	20%/yr	15%/yr
6/1/84	3	20%/yr	15%/yr
6/1/85	4	20%/yr	15%/yr

After Year 4, these costs were
escalated at 10% per year

Other Costs and Parameters

Project Life	= 1 year construction, 20 years operation
Operating Hours	= 7880 hrs/yr
Geothermal Pump Efficiency (Overall)	= 62% production = 47% reinjection
Production and ReInjection	
Well Depths	= 6000 ft. (production); 3000 ft (reinjection)
Annual Chemical Cost	= 4.8¢/1000 gal + 10%/yr escalation
Annual Insurance and Tax Cost	= 2% of capital cost + 10%/yr escalation
Annual Maintenance Cost	= 3% of capital cost + 10%/yr escalation
Income Tax Deductions	
- Intangible Drilling Costs	= 70% of total well capital cost
- Depreciation	= Straight-line to zero salvage
Income Tax Credits	
- Investment Tax Credit	= 10%
- Alternative Energy Tax Credit	= 15% of tangible well cost + surface equip- ment cost (exclude heat pumps and buildings)
Income Tax Rate	= 48.6%

FIGURE V-1 CORN PRODUCT OVERALL PROCESS FLOW DIAGRAM

Figure V-2 BASE PLANT STEAM AND NATURAL GAS DISTRIBUTION SYSTEM

Figure VI-2 GEOTHERMAL SYSTEM CONCEPTUAL DESIGN - Case 1

Figure VI-7 COMBINED GEOTHERMAL/COGENERATION SYSTEM CONCEPTUAL DESIGN - CASE II

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-1

CASE I

GEOTHERMAL ONLY

FRACTION OF BEST-ESTIMATE CAPITAL COST

CORN PRODUCTS, EAST MESA, CALIFORNIA

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-2

CASE II

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-3

CASE III

COGENERATION ONLY

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-4

II. Conclusions

The following conclusions have been drawn from the results of this study:

1. If a wet corn milling plant were built in East Mesa, California, it would be technically feasible and economically attractive to utilize the geothermal resources to displace natural gas as a plant energy source. The addition of a geothermal energy supply system (Case I) to the base plant considered in this study would require an incremental capital investment of \$1,902,000 (1st qtr., 1980 dollars). Based on 7880 hours per year of operation, about 42 million cubic feet of natural gas could be saved each year and 14.7 MBtu/hr of geothermal energy would be utilized. Assuming 20% per year escalation on natural gas prices through 1985, and 10% per year thereafter, the after tax rate of return on the incremental investment would be 28% and the corresponding payback period would be 3.8 years. Both of these are attractive for energy projects.

2. Relative to the base case, a combined geothermal/cogeneration system (Case II) would require an incremental capital cost of \$2,622,000. Based on the same escalation rates discussed in Item 1 above, the after-tax rate of return would be 46.1% and the corresponding payback period would be 2.2 years. Both of these are very attractive and significant improvements over Case I.

3. In the base wet corn milling plant, most of the fuel consumption is required to incinerate odorous waste gases at a temperature of 1750°F. This high temperature is necessary to eliminate the odors. After leaving the incinerator, the hot gases are routed through a waste heat recovery unit which produces almost exactly the amount of 150 psig saturated steam required for the processes. While the processes operate at relatively low temperatures, the need to add the

heat to the plant at levels up to 1750°F precludes all but a few preheat type of applications as candidates for geothermal utilization. In spite of this severe thermodynamic process constraint, the attractive paybacks listed in item 1 can be obtained.

4. The changes made to the base plant design required in order to achieve the savings indicated in Item 1 for Case I were as follows:

- a) Geothermal fluid was used to preheat the odorous waste gas stream before it entered the incinerator, thereby decreasing the amount of natural gas consumed.
- b) The steepwater evaporator was changed from a 950 HP motor driven mechanical vapor compression type to a steam heated, quadruple effect evaporator. The steam required was obtained by reducing the amount required by the starch dryer and deaerator as indicated in (c) and (d) below.
- c) In the base plant, the natural gas fired starch dryer was equipped with a steam heater which preheated the drying air to reduce gas consumption. In the modified design, geothermal energy was used to preheat the air to a higher temperature than was being achieved by the steam. The net result was a reduction in gas consumption by the dryer. Also, the steam which was replaced by the geothermal energy was diverted to operate the steepwater evaporator as described in (b).
- d) Geothermal energy was used to preheat the deaerator makeup water to a higher level than was possible with heat recovery unit blowdown alone. The steam originally used to provide this heat in the deaerator was then available for use in the steepwater evaporator as described in (b) above.

The plant design resulting from changes (a)-(d) above are called Case I throughout this report.

5. Greater geothermal energy utilization could be obtained if a combined geothermal/cogeneration system was installed. In such a system, some of the high temperature waste heat from the incinerator could be converted to about 2 MW of electrical power by a steam turbine/generator system. That portion of the waste heat so converted would not be available for the lower temperature process heating applications and could be replaced by geothermal energy. Indirectly, the geothermal energy would displace some of the electrical energy requirements of the plant. No additional natural gas would be burned to produce the electricity.

Such a system was analyzed during this study and is referred to as Case II throughout this report. In addition to the steam turbine/generator cycle, the other differences between Case I and II were as follows:

(a) The heat recovery unit design was revised so that it would produce 56,934 lb/hr of 850 psig/825°F steam in lieu of 64,044 lb/hr of 150 psig saturated steam.

(b) Steam from the heat recovery unit was routed to the straight, non-condensing steam turbine which exhausted to the process at 150 psig.

(c) The 7,100 lb/hr reduction in steam flow to the process was accommodated by using geothermal energy to heat the steepwater evaporator. Approximately 2,000 lb/hr of steam would have still been available to the evaporator, however, it was judged more economical to heat the evaporator entirely by geothermal energy and divert the 2,000 lb/hr to do additional preheating of the starch dryer, thereby further decreasing the fuel consumption of that unit.

(d) The higher steam drum pressures on the heat recovery unit increased the blowdown heat recovery to the extent that geothermal heating of the deaerator makeup water was dropped.

Relative to the base case, the Case II design would consume about 58 million cubic feet per year or 9% less natural gas. In addition, the amount of utility supplied electrical power would be reduced by 34% from 7500 kW to 4980 kW. In Case II, geothermal energy would be used at the rate of 20.4 MBtu/hr.

The combination of the two types of systems results in a partial synergistic effect since the cogeneration system used some of the incinerator waste heat to produce electricity rather than for process purposes. This affords an opportunity to increase the utilization of the geothermal well which would otherwise probably be underutilized.

6. Results of a sensitivity analysis indicate that the payback periods for Cases I and II would be attractive even if capital costs were 25% higher than the "best estimates".

7. The payback period for Case II, the combined geothermal/cogeneration plant are attractive even if zero cost escalation were assumed over the 20 year life of the plant.

There does not appear to be any institutional constraint which would prevent the construction of a wet corn milling plant in East Mesa, assuming an adequate market for the products exists within 100-200 miles. Shipping costs are such that attractive energy costs would not induce a corn milling company to build in an area which was a greater distance from the market.

III. Introduction

A. General

The objective of the DOE Geothermal Energy Development Program is to provide the nation with an economically and environmentally acceptable resource to supplement present energy sources. To accomplish this, the early development of a viable and growing geothermal industry is required. Under Contract No. DE-AC03-79ET 27231, the work described herein concentrated on site specific engineering and economic studies of the high temperature hydrothermal resources in the East Mesa area of the United States. In particular, an industrial team of Burns and Roe Industrial Services Corporation (BRISC) and Corn Products (a unit of CPC North America) studied the modification of a typical wet corn milling process which would hypothetically be installed at East Mesa and utilize the geothermal resources currently being explored by DOE in that locality. BRISC was the prime contractor and CPC was an unpaid participant.

The specific objective of this study is to provide a data base which could be used to assess the practicality of utilizing the geothermal resources in a wet corn milling process.

B. Study Objectives

The overall objective of the proposed study was to develop a base of engineering, economic, and institutional data which could be used by DOE to rapidly assess the practicality of utilizing the geothermal resources of the East Mesa, California site for a new corn processing plant.

In order to achieve the overall objective, efforts during the program were directed towards attainment of certain specific objectives. These specific objectives all involved the development of answers to certain questions which are stated below.

1. Based on the best available data, what ranges of values could reasonably be expected for the various geothermal reservoir design data in the East Mesa, California area (i.e., well location, depth, flow capacity, temperature, drawdown, etc.)?
2. For the ranges of values developed in (a), what processes within the corn milling plant could be adapted to utilize geothermal energy in place of energy sources used conventionally?
3. What plant design modifications would be required to convert the processes defined in (b) to use geothermal energy?
4. What design is proposed for the geothermal production well and supply system to the CPC plant (i.e. pumps; pretreatment system, if any; piping; controls; etc.)?
5. What approach is recommended or required for the disposal and/or utilization of the cooled geothermal brine?
6. What environmental emissions may be of concern and what quantities are expected? What technology is available for control of these emissions?
7. What is the cost of energy when supplied by the geothermal reservoir and when supplied in conventional forms?
8. What social, financial, environmental, or legal barriers to the proposed application exist? What ways are available to eliminate or reduce these barriers?

C. Work Scope

The contractual scope of work performed in order to accomplish the stated objectives was as defined by the following tasks:

Task 1.0 - Engineering and Design Studies

Based on available published data and contacts with other investigators, a prediction was made of the expected range into which the relevant geothermal reservoir data (i.e., temperature, flow capacity, depth, etc.) for the East Mesa area will fall. Process data, plant drawings, and energy data for the existing plant were compiled. Based on this information, a design concept was developed for the entire geothermal energy system from production well through the plant to final brine disposal.

A detailed design package was developed including process flow sheets and instrumentation diagrams, site plans, plant arrangement drawings and functional specifications for all new equipment.

Task 2.0 - Cost Estimates and Economic Analysis

Based on the design(s) produced in Task 1.0, a parametric analysis of capital and operating costs was performed for the range of geothermal design data developed in Task 1.0. A discounted cash flow of return type of analysis was utilized to evaluate the economic viability using geothermal energy in place of all or part of the conventional energy sources currently being considered. The cost of energy both when supplied in conventional form and when supplied by the geothermal system will be calculated over a 20 year life.

Task 3.0 - Analysis of Institutional Factors

Relevant social, financial, environmental, legal, and regulatory institutional relationships were examined and ways to eliminate any barriers they may present against the proposed application were explored.

In addition to the contractual scope of work defined above, a significant effort was also made to evaluate the relative economics of a combined geothermal/cogeneration system. The reasons for making this study are explained by subsequent sections of this report.

IV. Geothermal Resource Assessment

A. Imperial Valley/East Mesa Program

The East Mesa KGRA (Known Geothermal Resource Area) is one of several geothermal fields in the Imperial Valley in Southern California. It is located on the east side of the valley, approximately 7 miles southeast of Holtville, 18 miles east of El Centro and 115 miles southeast of Los Angeles. The terrain of the area is flat and the climate is typical of the desert regions of the southwestern United States. The location of the East Mesa KGRA is shown in Figure IV-1⁽¹⁾.

East Mesa has been the site of much geothermal exploration and development. Part of the field has been developed by the U.S. Bureau of Reclamation (USBR), which drilled five wells (Mesa 6-1, 6-2, 8-1, 31-1, all production wells, and 5-1, an injection well). These wells are now part of the Geothermal Component Test Facility, operated by Westec Services for the Department of Energy. (2, 3)

Twenty-four wells had been completed within the KGRA by December, 1979, including ten by Republic Geothermal, Inc. in the northern portion, the five Bureau of Reclamation wells in the central area and eight by Magma Power Co. to the south. There are four old abandoned wells on the outskirts of the area (Texaco Grupe-Ingebretsen No. 1, Magma Sharp No. 1, Shafer Barbara No. 1 and American Petrofina No. 27-1) and, additionally, many shallow wells in the area used for fresh water production. Well locations within the East Mesa KGRA are shown in the leasehold maps of Figures IV-2⁽⁴⁾ and IV-3⁽⁵⁾.

The various wells have been drilled to depths from 2950 to 9200 feet. The mean reservoir temperature is estimated to be in the order of 360°F and the reservoir is estimated to have a potential of 360 MWe for 30 years.⁽⁶⁾ A 10 MWe binary cycle power plant by Magma Power and a 48 MWe flashed steam power plant by Republic Geothermal are under development at East Mesa. (7)

Figure IV-2 East Mesa KGRA lease units.

XBL 789-11161

XBL 785-2539 A

Figure IV-3 Map of USBR leaseholds at East Mesa. Solid contours show the isotherm at 6000-ft depth; dashed contour shows the 300°F isotherm at 7000-ft depth.

B. Geothermal Reservoir Design Data

The East Mesa KGRA is on the east flank of the Salton structural trough. Fluid conditions within this area are highly site specific, since the subsurface geology, largely sand, sandstone and shale, lacks contiguity. Therefore, design data can only be estimated from the range of known data for existing East Mesa geothermal wells.

Table IV-1 lists measured geothermal characteristics for several East Mesa wells. Table IV-2 provides the chemical analysis for several DOE production wells. These data, along with the isotherm data of Figures IV-3 through 10 will be the basis for estimated fluid properties for this study.

Design Data Summary

The design data to be used for the current study are as follows:

Fluid temperature, °F	335
Fluid pressure, psig	100
Flow rate per production well, gpm	350 (max)
Fluid Composition	Table 2 - Mesa 6-2
Drawdown, ft	500 at 230 gpm
Production well depth, ft	6000
Reinjection well depth, ft	3000

DESIGN BASES

Fluid Temperature

Table IV-1 lists measured geothermal characteristics for several East Mesa wells. For the wells listed, bottom hole temperatures range from 309°F to 399°F, with wellhead temperatures ranging from 280°F to 335°F. The difference between bottom hole and wellhead temperatures represents heat transfer losses from the bottom hole to the wellhead and temperature depression corresponding to flashing from bottom hole pressure to wellhead pressure.

Table IV-1

East Mesa KGRA Wells

Geothermal Characteristics (2, 9)

<u>Well Name</u>	<u>Owner</u>	<u>Well Type</u>	<u>Depth, ft.</u>	<u>Temperature, °F</u> <u>Bottom Hole/Well Head</u>		<u>Pressure, psig</u> <u>Bottom Hole/Well Head</u>		<u>Maximum</u> <u>Flow, gpm</u>
Mesa 5-1	US DOE	Injection	6016	315		2450	50	240
Mesa 6-1	US DOE	Production	8030	399	280	3175	50	440
Mesa 6-2	US DOE	Production	6005	380	330	2450	100	300
Mesa 8-1	US DOE	Production	6205	354	305	2436	72	460
Mesa 31-1	US DOE	Production	6231	309		2406	68	300
Mesa 16-29	Republic Geothermal	Production	8021	360				837
Mesa 38-30	Republic Geothermal	Production	9009	349				1340
Mesa 18-28	Republic Geothermal	Production	8002	324				72

Table IV-2

East Mesa Geothermal Brine Chemistry
Mesa Well Head Unflushed (2) *

	<u>6-1</u>	<u>6-2</u>	<u>8-1</u>	<u>31-1</u>
	<u>mg/l</u>	<u>mg/l</u>	<u>mg/l</u>	<u>mg/l</u>
Chloride (Cl)	15,850	2,142	500	510
Barium (Ba)	14	0.25	0.15	0.15
Fluoride (F)	0.99	1.23	1.60	1.42
Ammonia (NH ₄)	40.75	14.7	4.95	2.45
Cesium (Ce)	2.75	0.38	0.14	0.20
Sodium (Na)	8,100	1,700	610	730
Strontium (Sr)	320	6.4	2.1	1.4
Boron (B)	9.75	7.45	1.6	2.5
Silica (SiO ₂)	320	269	389	274
TDS	26,300	5,000	1,600	2,900
Iron (Fe)	8.8	<0.1	<0.10	<0.10
Potassium (K)	1,050	150	70	85
Magnesium (Mg)	17.2	0.24	<0.05	<0.05
Bicarbonates (HCO ₃)	202	560	417	845
Sulfate (SO ₄)	42.8	156	173	183
Calcium (Ca)	1,360	16.4	8.5	8.9
Conductivity (25°C) umhos	40,000	6,000	3,200	4,700
pH	5.45	6.12	6.27	6.27

*Components present in small amounts are not listed, for clarity.

XBL 786-1867

Figure IV-4 Temperature contours ($^{\circ}\text{F}$) at 2000-ft depth for East Mesa KGRA (modified from TRW/Intercomp, 1976).

XBL 786-1866

Figure IV-5 Temperature contours ($^{\circ}\text{F}$) at 3000-ft depth for East Mesa KGRA (modified from TRW/Intercomp, 1976).

XBL 786-1863

Figure IV-6 Temperature contours ($^{\circ}\text{F}$) at 4000-ft depth for East Mesa KGRA (modified from TRW/Intercomp, 1976).

XBL 786-1868

Figure IV-7 Temperature contours ($^{\circ}\text{F}$) at 5000-ft depth for East Mesa KGRA (modified from TRW/Intercomp, 1976).

Figure IV-8 Temperature contours ($^{\circ}\text{F}$) at 6000-ft depth for East Mesa KGRA; shaded area is poorly reflective zone (modified from TRW/Intercomp, 1976).

Figure IV-9 Temperature contours ($^{\circ}\text{F}$) at 7000-ft depth for East Mesa KGRA; shaded area is poorly reflective zone.

The contour maps of Figures IV-3 through IV-9 show isotherms between 2000 and 7000 feet depths. The map of Figure IV-10 shows the 340°F isothermal surface depth contours.

The reported temperatures cover a wide range and are, obviously, both site specific and depth specific. The exact location of the Corn Milling Plant within the East Mesa KGRA has not been established, however, it appeared reasonable to select a fluid temperature of 335°F, the wellhead temperature of Mesa 6-2, as the wellhead temperature to be used for this study.

However, based on a review of Figures IV-2 through IV-10, it is possible that mineral rights to such a resource would not be available for lease, sublease or sale. Obviously, reductions in wellhead temperature or flow rate would have an adverse effect on the rates of return and payback periods reported later in this document.

Fluid Pressure

The data of Table IV-1 show bottom hole pressures ranging from 2406 to 3715 psig, with wellhead pressures ranging from 50 to 100 psig. The difference between bottom hole and wellhead pressures represents friction losses from the bottom hole to the wellhead and pressure depression corresponding to the change in static head from bottom hole elevation to wellhead elevation.

In order to maintain the geothermal brine below saturation at 335°F, and to keep carbon dioxide in solution, a minimum pressure of 75 psig was taken for this study.

Production Data

The data of Table IV-1 show a wide variation in flow rate between individual wells, which is not unexpected since the factors affecting well production may vary significantly between locations and at different depths. Republic Geothermal wells 16-29 and 38-30 are, in fact, located at fault zones, accounting for their high flows.⁽⁸⁾ However, the DOE production wells show significantly less variation among themselves, with flow rates between 300 and 460 gpm.

Provided the geothermal field can sustain the flow, the actual flow from a well will be determined by the downhole pump, which is limited by the casing size. Thus, within limits, the flow will be a function of the well design rather than the geothermal field limitations. Ultimately, wellbore pressure limits will actually determine whether or not the well will achieve the anticipated flow. A geothermal brine flow rate of 320 gpm was required for the current study, as detailed subsequently in this report. Based upon the data of Table IV-1, it seems reasonable to select a flow rate of 320 gpm as an attainable value to be used in this study.

Fluid Composition

The chemical analyses of the unflushed fluids for the DOE production wells are shown in Table IV-2. Mesa 5-1, being an injection well, is not included.

Mesa 6-1, probably because of its considerably greater depth, shows significantly more total dissolved solids than the other DOE production wells, and the data for 6-1, therefore, was not considered further.

The remaining three DOE production wells have similar chemical analyses. The chemical analysis for Mesa 6-2 was assumed to apply to this study, since it exhibits highest calcium and barium concentrations likely to cause scaling problems.

Drawdown

For a deep well drilled into a highly permeable aquifer, the water will normally rise to a level equal to the elevation of recharge of the aquifer. When water is pumped out of the well, the water level within the well will be depressed below the recharge level. This depression of elevation (expressed in feet or psi) is the drawdown, and since the pump must be placed at a depth in the well below the drawdown level, drawdown is a major factor contributing to capital and operating costs.

Drawdown is a function of several parameters, including withdrawal rate, aquifer permeability, aquifer transmissability, leakage from adjacent aquifers and the aquifer pressure. Experience at East Mesa indicates that for a flow of 230 gpm drawdown will be less than 500 feet.⁽⁸⁾ One study considered a maximum drawdown of 500 psi at a flow of 700,000 lbs/hr,⁽⁵⁾ which, since drawdown is directly proportional to flow rate, translates to a drawdown of slightly over 200 feet for a production rate of 230 gpm. Conservatively, a drawdown of 500 feet at 230 gpm was used in this study.

Production Well Depth

From Table IV-1 and Figures IV-3 through IV-10, it is evident that a production well at about 6000 feet can yield brine at an acceptable temperature and flow rate. It is also evident that a deeper well does not necessarily yield higher temperature brine or greater flow. These quantities are, obviously, site specific. Therefore, for study purposes, a production well depth of 6000 feet was used.

Reinjection Well Depth

The East Mesa subsurface geology results in reinjection well depth requirements that are highly site specific. Shallow wells require sufficient aquaclude to separate shallow fresh water aquifers from injection water, while deep wells must be sufficiently distant from production wells to assure that premature breakthrough of cool water from the injection well to the production well will not occur.

Existing East Mesa reinjection wells range in depth from about 2500 feet to greater than 5000 feet.^(2,8) The required depth could fall anywhere within this range, depending upon local geology and the location of the injection well relative to other production and injection wells. For study purposes, a reinjection well depth of 3000 feet was used.

C. Institutional Factors

1. Social

The East Mesa area is located in the Imperial Valley, entirely within lands administered by the Federal Government. The two predominant natural types of vegetation that lie within this area are Sonoran reosate bush scrub community and partially stablized desert dunes community.^(15,16) The nearest population centers are Holtville (3,580) which is 7 miles to the west and El Centro (21, 300) which is 18 miles to the west.

Construction of a Wet Corn Milling Plant at East Mesa should not significantly affect the ecosystem of the area, and social relationships should not present a barries to plant construction or operation provided the agriculture of the area is not disturbed, as discussed below.

A suitable labor force for plant operation should be available from Holtville, El Centro and environs.

2. Financial

a. Plant Economics

The economics of the application of East Mesa geothermal resources to the Wet Corn Milling Plant is discussed elsewhere in this report. Financial incentives such as the Geothermal Loan Guarantee Program, depletion allowances, intangible drilling cost deductions, and tax credits would obviously have a positive impact upon the project, either by improving the plant economics or reducing the financial risks.

b. Market Location

The location of a potential market for the products of a Wet Corn Milling plant is one of the major considerations in siting a plant. In fact, the existence of a major market within a maximum of about 200 miles from the plant is probably the preponderent consideration, since shipping costs for the products

far outweigh shipping costs for the raw materials. Reflecting the product shipping costs, an existing Wet Corn Milling plant adjacent to a market area precludes the construction of a new plant more remote from the market.

A Wet Corn Milling plant is currently being constructed for Corn Products in Stockton, California, to supply the existing market in the San Francisco/Oakland area. A Wet Corn Milling plant in the Imperial Valley could service a market within about 200 miles, which would include the Los Angeles and San Diego areas. Construction of a plant in East Mesa would not be indicated if such a market does not exist, regardless of the cost of energy for the individual plant. Therefore, determination of the existing market in the general area of the Imperial Valley is a prime financial consideration in the proposed application.

3. Environmental

The application of East Mesa geothermal resources to a Wet Corn Milling Plant may result in environments impacts typical of any geothermal effort. These possible major impacts include subsidence, seismicity, atmospheric impacts, hydrological impacts, noise, erosion and aesthetics. In general, these potential impacts are minimal and present no significant problem. However, several areas of potential environmental impacts are of special concern, as presented below.

a. Odor Emission

The control of emitted odors (from plant processes as opposed to geothermal fluid) is a major consideration in a Wet Corn Milling Plant, and is of particular concern in California because of the very stringent environmental regulations in that state.

The Wet Corn Milling process produces odorous waste gases in small concentrations. Effective elimination of these odors in order to satisfy California regulations, requires combustion of the waste gases at temperatures in the order of 1500 to 1750°F.

The Wet Corn Milling plant under construction at Stockton, California utilizes combustion of the waste gases for odor elimination, and plant constructed at East Mesa would require the same method, since there is no commercially proven alternative method to accomplish this. Only a small part of the natural gas required can be displaced by a geothermal source since the high temperature combustion is mandatory.

b. Water Use

Imperial County has been encouraging geothermal development in the area for the past several years. For Imperial County, the main environmental concerns appear to be water use and land subsidence.⁽¹⁷⁾ The economy of Imperial County is built around the agricultural use of the land, which is highly dependent on irrigation water. This makes water an important commodity in the area. The proposed geothermal application to a Wet Corn Milling plant uses only geothermal water from the production well, and thus poses no threat to the irrigation water supply system in this regard. However, the Wet Corn Milling plant itself requires process water, which would have to be provided by the existing supply system. Therefore, the process water requirements of the plant would have to be integrated into the Imperial Irrigation District allocations. Note that economic analyses in this report do not consider any cost differences for process water.

c. Subsidence

The Imperial Valley has a natural land profile which has enabled the installation of an intricate gravity fed irrigation and drainage system. Disruptive of this system by induced subsidence would have a severe impact upon the agricultural use of the land. Replacement of the geothermal fluid after use is thought to reduce or prevent subsidence. Therefore, reinjection is generally required to reduce or preclude land subsidence. Since total

re injection of all the geothermal fluid used in the Corn Milling plant is proposed, induced subsidence is not anticipated to be a problem.

4. Legal/Regulatory

As with any geothermal development, and for California development in particular, geothermal application in a Corn Milling plant in East Mesa would be subject to a wide range of rules and regulations administered by various agencies of the Federal, State and County governments. The California procedures and regulations are the most stringent in the nation, stemming primarily from the California Environmental Quality Act, which insures that all local governments control new development in a manner consistent with the policy guidelines of the act. (15)

Figure IV-11 shows the administrative and environmental requirements for development of geothermal resources on federal lands. Requirements for development of geothermal resources on federal lands are distinct in that the concept of full development is used from the outset. Issuing a federal lease for geothermal development is contingent on the suitability and approval of total development. This initial requirement is the most significant impediment to developers of geothermal resources on federal lands. (15)

There are various participants in geothermal development on a state level, operating in a wide range of activities, including land leasing, regulation and funding. A number of the California State Agencies that are involved and a brief summary of their areas of responsibility are presented in Table IV-3. (17)

On a county level, Imperial County continues to encourage geothermal development in the area. The County has adopted a Geothermal Element to their General Plan which lays the necessary groundwork and establishes goals and policies for geothermal development. A Wet Corn Milling plant at East Mesa would, of necessity, require integration into this General Plan.

Table IV-3 Some California State Agencies That are Concerned
With Geothermal Resources Development

<u>STATE AGENCY</u>	<u>AREA OF RESPONSIBILITY</u>
STATE LANDS COMMISSION (SLC) _____	LEASING OF STATE LANDS ¹
DIVISION OF OIL & GAS (DOG) _____	WELL & RESERVOIR PROTECTION ^{2a}
DIVISION OF MINES & GEOLOGY _____	GEOLOGIC STUDIES & RESOURCES ASSESSMENT ^{2b}
ENERGY COMMISSION (CERCDC) _____	POWER PLANT CERTIFICATION ³
AIR RESOURCES BOARD (ARB) _____	AIR QUALITY ⁴
WATER RESOURCES CONTROL BOARD (SWRCB) _____	WASTE DISCHARGE ⁴
SOLID WASTE MANAGEMENT BOARD (SWMB) _____	SOLID WASTE DISPOSAL ⁴
PUBLIC UTILITIES COMMISSION (PUC) _____	RATE REGULATION & CERTIFICATION OF PUBLIC CONVENIENCE & NECESSITY ⁵
DEPARTMENT OF FISH & GAME _____	FISH & WILDLIFE IMPACTS ⁶
DEPARTMENT OF WATER RESOURCES (DWR) _____	WATER SUPPLY & ENERGY DEVELOPMENT ⁷
GOVERNOR'S OFFICE OF PLANNING & RESEARCH (OPR) _____	STATE & LOCAL LAND USE PLANNING, ENVIRONMENTAL REVIEW, PERMIT ASSISTANCE

¹An oversee operation on state-owned lands.

²Within the Dept. of Conservation:

^aRegulates well drilling activities (see AB 2644: Table 4-3.)

^bDevelopes assessments in conjunction with SLC and DOG. Conducts seismic surveys.

³For all electric power plants over 50 MWe, including geothermal. Also responsible for formulating and coordinating program of alternate energy resources research and development.

⁴ARB, SWRCB and SWMB exercise federally delegated authority over geothermal developments.

⁵Sets rates for investor-owned utilities only.

⁶Department within the Resources Agency.

⁷Major responsibility is water supply. DWR is also involved in geothermal power development.

Although compliance with the rules and regulations of the wide range of agencies involved in general, and permitting delays in particular, tends to slow geothermal development, there are no apparent regulations which would drastically hinder geothermal application to a Wet Corn Milling Plant at East Mesa.

V. DESCRIPTION of BASE PLANT

A. Process Description *

Wet corn milling plants produce a variety of products, the principles ones being corn oil, corn syrup, corn starch and animal feed.

The overall wet corn milling process is shown in Figure V-1. Wet milling of corn is a continuous process with all parts run as an integrated whole. No one product can be produced unless the corn grinding, finishing, and by-products departments are running at the same time. It is impossible to produce some critical or essential products without also producing some of the other items of the corn refining industry. The activity, therefore, cannot be fractionalized on a product-by-product evaluation, but must be considered on an industry-wide basis, and the industry must have sufficient manpower to finish all the varied products that result from the grinding of corn in order to make those products which may be considered most critical or essential.

The raw material of the wet miller is almost exclusively the kernels of hybrid yellow dent corn containing about 65% starch on a fresh weight basis. No other part of the corn plant is used in the process. Historically, the industry isolated only starch from the other components of the kernel, the other fractions of the corn kernel being discarded as without commercial value. Today, the entire kernel is used, and there is no waste whatever.

Chemically from 10% to 25% of the corn kernel is water. The remainder is made up of about 80% starch and other carbohydrates; 10% protein; 4.5% oil; 3.5% fiber; and 2% ash or minerals. The starch is probably the most economic and the purest organic material of American agriculture available for large-scale

*This section taken from The Corn Refining Industry, Corn Refiners Association, Inc., Washington, DC

industrial use. Physically, the corn kernel is separated in the wet-milling process into four principal parts: (1) the outer skin, called the bran or hull; (2) the germ (containing most of the oil); (3) the gluten, a high-protein component; and (4) starch. The bran and germ are largely distinct entities. Just inside of the hull is a mixture of gluten and starch. The central portion of the kernel consists mostly of starch, with some protein and a trace of oil also present.

The wet milling process consists of several distinct parts: (1) the separation process, which divides and isolates the components of the corn kernel to obtain starch as the principal end product and steepwater, oil and feeds as by-products; (2) the hydrolysis process which converts some of the starch to syrup or dextrose; and (3) the starch modification process which changes its characteristics by physical or chemical treatment.

1. The Separation Process

Shelled corn is delivered to the wet-milling plant in boxcars (2,000 bushels per car) and unloaded into a grated pit. The corn is then elevated to temporary storage bins via scale hoppers for weighing and sampling. Next, the corn passes through mechanical cleaners designed to separate unwanted substances such as pieces of cobs, sticks and husks, as well as metal and stones. The cleaners agitate the kernels over a series of perforated metal sheets so that the smaller foreign materials drop through the perforations while a blast of air blows away chaff and dust, and electromagnets draw out nails and bits of metal. Coming out of storage bins, the corn is given a second cleaning before going into huge "steep" tanks.

At this point, the use of water becomes an essential part of the corn refining process. The cleaned corn is typically moved into huge wooden or metal tanks holding 2,000 to 6,000 bushels, and soaked for 36 to 48 hours in circulating warm (120°F) water containing a small amount of sulphur dioxide to control fermentation and facilitate softening. At the end of the steeping process, the steepwater contains much of the soluble protein, carbohydrates, and minerals of the corn kernel, and is drawn off as the first by-product of the process. Steepwater, unmodified and modified, is an essential nutrient for production of antibiotic drugs, vitamins, amino acids and fermentation chemicals. It is also an effective growth supplement for animal feeds.

From the steeps, the softening kernels go through degerminating mills, which are designed not for fine grinding but for tearing the soft kernels apart into coarse particles, thereby freeing the rubbery oil-bearing germ without crushing it, and loosening the bran. The wet, macerated kernels are then sluiced into flotation tanks called germ separators, or centrifugal hydro-cyclones. The germs, which are lighter than the other components of the kernel, float to the surface and are skimmed off. The germs are then dewatered and processed for the recovery of corn oil by oil expellers or extractors (heat and pressure) and by means of solvents.

Practically all of the oil is removed, settled, filtered, refined, and otherwise processed into clear edible oil for salad dressing and frying, and into "corn oil foots" or "soap stock" for use by soap manufacturers. The residue of the germ after oil-extraction is ground and marketed as corn germ meal, or may become a part of corn gluten feed or meal.

The remaining mixture of starch, gluten, and bran (hull), which is finely ground, is washed through a series of screens to sieve the bran from the starch and gluten. The hull becomes part of corn gluten feed.

The remaining mixture of gluten and starch is pumped from the shakers to high-speed centrifugal machines, which, because of the difference in specific gravity, separate the relatively heavier starch from the lighter gluten. After further processing, the protein-rich gluten is sold as such, or becomes corn gluten meal, or may be mixed with steepwater, corn germ meal, and hulls to become corn gluten feed. Gluten may also be made to yield a highly versatile protein, zein; amino acids such as glutamic acid, leucine, and tyrosine; or xanthophyll oil for poultry rations.

Having been separated from the kernels, the starch is now ready for washing, drying or further processing into numerous dry-starch products, or into dextrin, or into syrup and sugar. From a 56-pound bushel of corn, approximately 32 pounds of starch is produced, about 14 1/2 pounds of feed and feed products, and about 2 pounds of oil. The remainder is water.

2. The Conversion Process

More than half of the total production of starch is converted into syrup dextrins or dextrose by acid hydrolysis and/or enzyme action, or heat treatment. Dextrose is the sugar in human blood. In converting starch to dextrose, the refiners simulate the process of human digestion by turning carbohydrates into sugar. As a food or therapeutic agent, dextrose when introduced into the human body, is almost instantly absorbed into the bloodstream as food.

In its natural state, starch is not soluble in water. By a roasting or chemical treatment process, changes may be effected enabling the starch to dissolve in water for form a wide variety of pastes and gums.

Starch, mixed with water and heated in the presence of weak hydrochloric acid, breaks down chemically, by an action called hydrolysis, into different and simpler substances. If the hydrolysis or conversion of corn starch is interrupted before final conversion, a non-crystallizing corn syrup is obtained. Many varieties may be made by supplemental use of enzymes to meet specific functional and commercial requirements. The solids content is varied to suit the requirements of the users.

If more acid is used and the conversion is continued, or if the starch is suitably treated with enzymes, it changes almost entirely to dextrose. The corn sugar may be crude or refined, and prepared in various forms. A by-product is corn sugar molasses (hydrol).

B. Energy Utilization

Prior to being modified to utilize geothermal energy, the total energy requirement for the selected wet corn milling process included 80.3×10^6 Btus/hr of natural gas to the incinerator, 6.4×10^6 Btus/hr of natural gas to the starch dryer and 7500 kWh/hr of electrical energy. Figure V-2 shows the existing steam and natural gas distribution system for the plant. * Data for individual processes in the plant are shown in appendix D*.

The scrubbed odorous gases from the gluten, germ, starch and feed dryers for the proposed plant, have to be oxidized at 1750°F in an incinerator to

Figure V-2 BASE PLANT STEAM AND NATURAL GAS DISTRIBUTION SYSTEM

satisfy California EPA regulations for odor control. About 73 million Btus/hr of waste heat from the incinerator is used to generate 64,066 lbs/hr of 150 psig saturated steam in the heat recovery unit. Figure V-2 shows that the amount of steam generated in the waste heat recovery unit is sufficient to supply the steam requirement for the whole plant. The energy diagrams shown in appendix D describe in greater detail all individual processes that consume energy.

*The degree of detail of the data presented here is governed, in large part, by CPC confidentiality requirements. More detailed data has been made available by CPC for study purposes, but confidentially considerations preclude this publication.

VI. GEOHERMAL BRINE APPLICATIONS

Due to the large amounts of waste heat made available, the need to incinerate the waste gas stream at 1750⁰F seriously limits the amount of natural gas which can be displaced by the relatively low temperature geothermal energy source. Preliminary investigations have indicated that within the current state-of-the-art, there are no other commercially proven processes available to eliminate the odor producing contaminants.

The incinerator waste heat will generate sufficient amounts of steam to supply the thermal energy requirement for the whole plant. Therefore, the most practical uses for geothermal energy in the plant are to: 1) preheat the odorous waste gas stream before it enters the incinerator; 2) preheat the dry air entering the starch dryer; 3) preheat the softened makeup water entering the deaerator; and 4) preheat the corn steeping water before it enters the steepwater evaporator. This section will describe the modifications made to the base plant in order to incorporate these utilization methods.

A. Geothermal Supply System

1. Geothermal Wells

Although over twenty wells have been drilled at East Mesa, cost data for these wells are meager, primarily because of the proprietary nature of this information.

Well costs vary widely, depending upon such factors as drill rig availability, depth of hole, diameter of hole, number of holes to be drilled and problems encountered during drilling because of subsurface geology. The last factor in particular can make a substantial difference in cost between two otherwise identical wells drilled in close proximity to each other. As a result, it is difficult to predict specific well costs with any great precision.

Order of magnitude estimates of well costs at East Mesa have been obtained from several sources (10,11,12). They are based upon general knowledge of East Mesa conditions and well drilling history. Additionally, Figure VI-1⁽¹³⁾ estimates well costs as a function of depth, from data on nineteen geothermal wells of varying depths and several locations. These cost estimates are summarized below.

Estimate 1⁽¹⁰⁾

Production well to	6000 ft	\$800,000
Reinjection well to	3000 ft	650,000

Estimate 2⁽¹¹⁾

Production well to	6000-6500 ft	\$1,100,000
Reinjection well to	6000-6500 ft	800,000

Estimate 3⁽¹²⁾

Production well to	7000 ft	\$800,000 - \$1,000,000
--------------------	---------	-------------------------

Estimate 4⁽¹³⁾ (1978 prices)

Well to 6000 ft	\$600,000 - \$1,000,000
Well to 3000 ft	\$250,000 - \$ 400,000

The cost estimates exhibit a considerable range, but do present a reasonable basis for the current study. Based upon these estimates, costs for the production and injection wells will be taken as:

Production well to 6000 ft	\$1,000,000
Reinjection well to 3000 ft	\$ 500,000

Since there is a substantial uncertainty in actual well costs, a sensitivity analysis was performed to determine the effect of well cost on plant economics. (See Section VII.)

At first glance, it may appear that a capital cost credit could be applied to the geothermal system due to the fact that the capacity of the incinerator and waste heat recovery units could be reduced by an amount corresponding to the geothermal energy input. However, the plant design must contain some provision to allow for continued production during any geothermal system outage. This design, therefore, assumes that the incinerator and waste heat recovery unit would be designed to provide this backup capability. Therefore, the capacity of this equipment was assumed to be the same as in the Base Plant (Section V), and no capital cost credit was applied to the geothermal system.

Figure VI-1
Well Costs versus Depth. Corrected to 1978 prices.

2. Downhole Production Well Pump

A downhole pump will be required in the production well to pump the geothermal fluid at the required flow rate while providing sufficient head to compensate for drawdown, elevation differences and frictional losses, and to insure the maintenance of adequate pressures within the system to prevent escape of carbon dioxide from solution.

The two types of pumps which are applicable to downhole use are electric motor driven submersible pumps and shaft driven vertical turbine pumps. The submersible pump operates as a single unit with both pump and motor submerged at the desired level in the well. The discharge tubing, electric supply cable and safety rope run from the surface through the well to the motor/pump assembly, which can be set at any desired depth in the well. The obvious advantage of a submersible pump is the lack of limitation on pump setting depth. However, since the windings of the electric motor are cooled by the geothermal fluid, there is a limit to the fluid temperature that can be handled before the motor is damaged. This limiting temperature is in the order of 150°F. (Although manufacturer claims are for higher temperature operation, extended operation much above 150°F is doubtful.) Therefore, the considerably higher fluid temperatures at East Mesa would appear to preclude the use of a submersible pump.

The most commonly used pump for a geothermal well is a shaft driven vertical turbine downhole pump. The pumps bowls and impellers are set to the required depth within the well, with the impellers connected by a shaft to a surface mounted electric motor. The obvious advantage in this case is that fluid temperature is not a problem since the electric motor drive is not submerged in the fluid. Therefore, a shaft driven pump is applicable to the East Mesa geothermal fluid conditions.

Although manufacturer claims have been made for shaft driven pump settings in excess of 1000 feet, shaft stretch and bearing problems normally limit maximum shaft lengths to 600 to 800 feet. Shaft bearing failure has been reported as a major problem for an 800 ft. long shaft driving a downhole pump at one East Mesa site ⁽⁹⁾. For the present study, satisfactory operation of a shaft driven downhole pump was assumed for a pump set at about 600 feet, to allow for an anticipated 500 feet of drawdown. To insure conservation, the total pump head was set at 1000 feet.

The pump specifications for this application were:

Peerless vertical turbine lineshaft pump

Pump set at 600'

Flow = 350 gpm at 1000' head

Pump efficiency = 65%

Motor horsepower = 125

Pump cost (including motor) = \$70,000

3. Geothermal Brine Chemistry and Treatment

The source of geothermal brine to be used in the wet corn milling plant was assumed to have the same analysis and properties as the geothermal brine at East Mesa KGRA well 6-2 as shown in Table VI-1.

Calculation of the Langlier Index and ionic strength equations confirmed that the fluid was supersaturated with calcium and strontium sulfate, and borderline saturated with barium sulfate. Silica appeared to be saturated at the temperature of the fluid and should slowly precipitate at lower temperatures and higher concentrations.

Since the geothermal brine to be used in the process was not to be concentrated, threshold chemical additives were the only pretreatment method

Table VI-1

East Mesa Geothermal Brine Chemistry
Mesa Well Head Unflushed (2) *

	<u>6-1</u> <u>mg/l</u>	<u>6-2</u> <u>mg/l</u>	<u>8-1</u> <u>mg/l</u>	<u>31-1</u> <u>mg/l</u>
Chloride (Cl)	15,850	2,142	500	510
Barium (Ba)	14	0.25	0.15	0.15
Fluoride (F)	0.99	1.23	1.60	1.42
Ammonia (NH ₄)	40.75	14.7	4.95	2.45
Cesium (Ce)	2.75	0.38	0.14	0.20
Sodium (Na)	8,100	1,700	610	730
Strontium (Sr)	320	6.4	2.1	1.4
Boron (B)	9.75	7.45	1.6	2.5
Silica (SiO ₂)	320	269	389	274
TDS	26,300	5,000	1,600	2,900
Iron (Fe)	8.8	<0.1	<0.10	<0.10
Potassium (K)	1,050	150	70	85
Magnesium (Mg)	17.2	0.24	<0.05	<0.05
Bicarbonates (HCO ₃)	202	560	417	845
Sulfate (SO ₄)	42.8	156	173	183
Calcium (Ca)	1,360	16.4	8.5	8.9
Conductivity (25°C) umhos	40,000	6,000	3,200	4,700
pH	5.45	6.12	6.27	6.27

*Components present in small amounts are not listed, for clarity.

considered necessary for control of carbonate scale. In addition to threshold chemical treatment, the geothermal brine was to be kept above 75 psig to keep carbon dioxide gas completely in solution. The selected threshold chemical was a phosphonate type that would be effective at temperatures above 250°F⁽¹⁸⁾.

To prevent silica from precipitating, the geothermal brine reinjection temperature must be restricted to a minimum of 160°F. Therefore, in order to provide a marginal safety, a design reinjection temperature of 200°F was used.

4. Injection Pump

Disposal of the geothermal fluid was accomplished by injection of 100% of the fluid into a reinjection well. A horizontal centrifugal pump, surface mounted at the injection wellhead, was used for this service.

It was assumed that injection pressure head would be equal to the production wellhead with additional pressure allowance to account for gradual fouling of the well with continued use, and to account for any injection of debris, scaling, etc.⁽¹⁴⁾. On this basis, the total head requirements for the pump sizing were set at 850 feet.

The injection pump specifications for this study were:

Pump designation	2 x 3 x 13 GSJH
Flow	320 gpm
Head	850 feet
Discharge diameter	2 inches
Suction diameter	3 inches
Number of stages	2
Efficiency	49%
Speed	3600 rpm
NPSH	13 ft
Length	80 inches (including motor)
Width	31 inches
Height	30 inches
Motor required	125 hp 3600 rpm
Price, excluding motor	\$24,000

B. Case I - Geothermal Surface System Conceptual Design

1. Process Description

Figure VI-2 shows the conceptual design with geothermal brine energy application for the proposed wet corn milling plant.

In this conceptual design, geothermal brine at about 335°F would be first pumped to two 20,000 gallon storage tanks and then it would be used to preheat the intermediate loop softened water and odorous waste gases to the incinerator. In order to protect against possible contamination of products or steam plant equipment with geothermal fluid in the event of a heat exchanger leak, the intermediate softened water loop has been incorporated to transfer heat from the geothermal fluid to the starch dryer, steepwater evaporator, preheater, and the deaerator make-up water heater. The total amount of geothermal brine required, on average, would be 115,775 lbs/hr, of which 86,165 lbs/hr preheat the intermediate loop softened water up to 325°F and 29,610 lbs/hr preheat the odorous waste gas stream up to 300°F before it enters the incinerator. The intermediate loop water at 74,676 lbs/hr and 325°F would then be used to heat the dry air to the starch dryer up to 295°F and the makeup softened water to deaerator up to 214°F.

Since the geothermal brine is not concentrated, the geothermal brine will be kept above 75 psig, and threshold treatment at 5 ppm will be a feasible pretreatment to prevent calcium carbonate, calcium sulfate and barium sulfate scaling. Also, the geothermal brine temperature will be above 160°F to prevent silica precipitation.

As part of this conceptual design, the electrical driven (950 hp) steepwater vapor compression evaporation unit will be replaced by a quadruple effect evaporator, heated by 11,235 lbs/hr (max) of 150 psig saturated steam, which is being made available due to geothermal preheating of the dry air entering the starch dryer.

Figure VI-2 GEOTHERMAL SYSTEM CONCEPTUAL DESIGN - Case 1

2. Piping and Equipment

(a) Piping

As shown on the geothermal system conceptual design plot plan Figure VI-3, the production well is assumed to be 500 feet away from the plant and 1,000 feet away from the reinjection well. For the most part, geothermal brine piping to plant and reinjection well will be buried. All the piping within the plant area is raised approximately 25 feet above the grade so that it does not provide an obstacle for access or maintenance.

All piping material will be carbon steel. Piping containing geothermal brine will be schedule 80, and piping for softened water will be schedule 40. The wall thickness of geothermal brine piping selection is based on the results of both laboratory and field corrosion tests in East Mesa nonaerated wellhead fluid which indicated corrosion rates ranging from 3.2-17.3 mills/year⁽¹⁹⁾.

Figures VI-4 & 5 show isometrics of the interconnecting piping at the production wellhead and the reinjection wellhead, respectively.

Figure VI-6 shows an isometric of the geothermal brine and intermediate softened water piping systems within the plant limits.

Table VI-2 defines the quantity and specifications for all piping used.

(b) Surface System Equipment

All the equipment that is related to the geothermal energy application is described as follows. An equipment list is shown on Table VI-3.

(1) Geothermal Brine Pump

The Geothermal Brine pumps are horizontal type centrifugal pumps with 316 stainless steel casings and impellers while the shafts are monel. These materials are used due to their corrosion resistance to brine. The pump is rated at 375 gpm and is driven by a 480 volt, 3 phase, 60 hertz motor rated at 30 hp.

FIGURE VI-4 GEOTHERMAL BRINE PRODUCTION WELLHEAD PIPING DIAGRAM

FIGURE VI-5 GEOTHERMAL BRINE REINJECTION WELLHEAD PIPING DIAGRAM

VI-13

PRELIMINARY ISSUE	ISSUE FOR R/D	ISSUE FOR CONSTRUCTION	ZERO ISSUE	0	BRISC APPROVAL	CLIENT APPROVAL
----------------------	------------------	---------------------------	---------------	---	-------------------	--------------------

FIGURE VI-6 GEOTHERMAL SYSTEM PIPING DIAGRAM - MAIN PLANT AREA

(2) Threshold Additive Pumps

The two threshold additive pumps are controlled volume simplex-diaphragm plunger pumps with 316 stainless steel heads and check valves and Teflon diaphragms. These materials are used due to their resistance to corrosion by the chemical solutions being pumped. Each pump is rated at 3 gph and flooded suction. Each pump includes a 480 volt, 3-phase, 60 hertz motor rated at 1/4 hp.

(3) Intermediate Loop Softened Water Pump

The two softened water pumps are horizontal type centrifugal pumps with all 316 stainless steel materials. Each pump is rated at 150 gpm. Each pump includes a 480 volt, 3-phase, 60 hertz motor rated at 7 1/2 hp.

(4) Threshold Additives Mixing Tank

The threshold additives mixing tank is vertical, of 316 stainless steel, 42 inches in diameter by 50 inches in height. The top of the tank is flat and is hinged for access to the tank. The capacity of the tank is 250 gallons. An agitator is fitted to the tank for mixing with 316 stainless steel shaft and propeller. The agitator includes a 480 volt 3-phase, 60 hertz motor rated at 1/4 hp.

(5) Incinerator Waste Gas Preheater

The incinerator preheater is single pass fin tube type heat exchanger with geothermal brine on the tube side and waste gas on the fin side. The heater uses 29,610 lbs/hr of geothermal brine to heat the 88,636 lbs/hr of waste gas to 300°F. The heater has a 37-7/16 inches casing height, an 11-1/2 feet tube length, and is 6 rows deep with a total of 146 tubes. The total heating surface is 18,246.2 ft². The tubes are titanium 5/8 inch OD and

0.035 inch wall thickness. The tube sheets are titanium, fins are copper solder coated and water box headers are carbon steel. The fluid pressure drop is 21.6 feet of water, and the air side loss is 2.14 inches of water.

(6) Starch Dryer Dry Air Preheater

The starch dryer preheater has a 41-5/8 inch casing height, a 12 feet tube length, and is 10 rows deep with a total of 24 tubes. The heater is a single pass fin tube type heat exchanger with softened water on the tube side and dry air on the fin side. The heater uses 60,602 lbs/hr. of softened water to heat 194,236 lbs/hr dry air to 295°F. The total heating surface is 17,846.1 ft². The tubes are copper and the fins are copper solder coated. The headers are carbon steel and the casing is 16 gauge galvanized sheet steel. The fluid pressure drop is 12.8 feet of water, and the air side loss is 1.49 inches of water.

(7) Intermediate Loop Softened Water Preheater

The softened water preheater is 9'-3 1/2" long by 1'-11 1/4" wide and has a 5'-1 1/8" overall height. The preheater is a single pass plate type heat exchanger which uses 86,165 lbs/hr of geothermal brine to heat 74,676 lbs/hr of softened water up to 325°F. The total surface area is 1288 ft² with 314 titanium plates measuring 17 1/2 inches long and 45 inches wide. The heat exchanger frames are carbon steel and are lined with a corrosion resistant epoxy paint.

(8) Deaerator Softened Water Preheater

The deaerator softened water preheater is shell and tube type heat exchanger 8 5/8 inches in diameter and 8 feet long. The preheater has an 84 inch long U tube bundle with 6 tube passes and 2 shell passes. Total heating

surface is 55 ft² with 20 U-tubes at 3/4" OD and 18 BWG. The softened water at 37.7 gpm is heated by 28 gpm of intermediate loop softened water up to 214°F. The tube side pressure drop is 5.5 psi and the shell side is 4.9 psi.

(9) Steepwater Evaporator

The steepwater evaporator is a plate type quadruple effect evaporator. The first three effects operate on a single pass rising and falling film principle and the fourth effect is a force circulation design plate type heat exchanger. The plates are 316 stainless steel and the frames are carbon steel material. The first three effects consist of a total of 172 plate units and 3526 ft². The fourth effect consists of 4 passes with 320 plates and a total surface area of 2400 ft². The overall dimension is 40 feet long by 24 feet wide and 20 feet high.

(10) Heat Recovery Section

The heat recovery section is a shell and tube type heat exchanger which generates saturated steam. The unit is rated at a capacity of 70,000 lbs/hr of 150 psig saturated steam.

(11) Geothermal Brine Production Well Storage Tanks

The two geothermal brine production well storage tanks are horizontal carbon steel vessels and are 10 feet 6 inches in diameter by 31 feet in length with ellipsoidal dished heads. Each vessel has a capacity of 20,000 gallons. The interior surface of the vessel is lined with an epoxy phenolic coating to protect the carbon steel shell from the corrosive effects of the hot geothermal brine. The exterior surface of the vessel has 4 inches of insulation with a weather-proof jacket. Each vessel is rated at 150 psi.

(12) ReInjection Brine Storage Tank

The reinjection brine storage tank is horizontal carbon steel vessel and is 10 feet 6 inches in diameter by 15 feet 6 inches in length with ellipsoidal

dished heads. The vessel has a capacity of 10,000 gallons. The interior surface of the vessel is lined with an epoxy phenolic coating to protect the carbon steel shell from the corrosive effects of the hot geothermal brine.

3. Energy Utilization

The total energy requirement for the geothermal system conceptual design includes 76.2×10^6 Btu/hr of natural gas to the incinerator, 4.8×10^6 Btu/hr of natural gas to the starch dryer and 6965 kWh/hr of electrical energy.

This application of geothermal energy replaced about 14.7×10^6 Btu/hr from the base plant and this includes the preheating of odorous waste gases to the incinerator, makeup to the the deaerator and dry air to the starch dryer. In addition, the replacement of the electrically driven (950 hp) steepwater vapor compression unit with a thermal four effect evaporator reduces the electrical energy consumption from 7500 kWh/hr to 6965 kWh/hr; and a net savings of 535 kWh/hr.

Table VI-2 Piping List - Case I

<u>Service</u>	<u>Qty.</u>	<u>Description</u>
1. Geothermal Brine From Production Well	721ft	4 inch OD, Sch. 80 with fiberglass insulation
2. Geothermal Brine From Production Well	219ft	2 1/2 inch OD, Sch. 80 with fiberglass insulation
3. Geothermal Brine to Reinjection Well	235ft	2 1/2 inch OD, Sch. 80 with fiberglass insulation
4. Geothermal Brine to Reinjection Well	74ft	4 inch OD, Sch. 80 with fiber-insulation
5. Geothermal Brine to Reinjection	1535ft	4 inch OD, Sch. 80
6. Softened Water	25ft	4 inch OD, Sch. 40
7. Softened Water	149ft	3 inch OD, Sch. 40
8. Softened Water	212ft	1 1/2 inch OD, Sch. 40

Table VI-3 Major Equipment List - Case I

<u>Service</u>	<u>Qty</u>	<u>Description</u>
1. Geothermal Brine Pump	1	Horizontal type centrifugal pumps rated at 375 gpm and 30 hp motor. Materials of construction are 316 stainless steel casing and impeller while the shafts are monel.
2. Threshold Additives Pumps	2	Controlled volume, simpler-diaphragm plunger type. 3 gph max flow, 1/4 hp motor and flooded suction. Stainless steel body and Teflon diaphragm.
3. Softened Water Pumps	2	Horizontal, centrifugal pump. 150 gpm flow. 7-1/2 hp motor. Materials of construction are cast iron body, bronze impeller and 316 stainless steel shafts.
4. Threshold Additives Mixing Tank	1	Vertical tank, 250 gallon capacity, 42 inches in diameter, 50 inches overall height, with flat, hinged top. Stainless steel construction.
5. Threshold Additives Agitator	1	Stainless steel propeller and shaft agitator with clamp for connection to mixing tank. 1/4 hp motor.
6. Incinerator Dry Air/Water Vapor Preheater	1	Single pass fin tube type heat exchanger. 37-7/16 inches casing height by 11-1/2 feet tube length. Titanium tubes and copper solder coated fins
7. Starch Dryer Dry Air Preheater	1	Single pass fin tube type heat exchanger. 41-5/8 inches casing height by 12 feet tube length. Copper tubes and copper solder coated fins.
8. Softened Water Preheater	1	Plate type heat exchanger. Carbon steel frame with titanium plates. Total heating surface area is 1288 ft ² . Overall dimension is 9' 3-1/2" L x 3' 1-1/8 H x 1' 11-1/4" W.

Table VI-3 Major Equipment List - Case I (con't)

<u>Service</u>	<u>Qty</u>	<u>Description</u>
9. Softened Water Preheater to Deaerator	1	Shell and tube type heat exchanger measure at 8-5/8" diameter and 8' length. Tubes material is 304 stainless steel and carbon steel shell.
10. Steepwater Evaporator	1	Quadruple plate type effect evaporator. Overall dimension is 40 feet long by 24 feet wide and 20 feet high. Material is of construction 316 stainless steel plates and carbon steel frames. Total surface area is 5926 ft ² .
11. Heat Recovery Section	1	Shell and tube type heat exchangers. Generate 70,000 lb/hr of 150 psig saturated steam.
12. Geothermal Brine Production Storage Tank	2	Horizontal tank, 20,000 gallon capacity, 10 feet 6 inches in diameter by 31 feet length. Material of construction carbon steel.
13. Reinjection Brine Storage Tank	1	Horizontal tank, 10,000 gallon capacity, 10 feet 6 inches in diameter by 15 feet 6 inches length. Material of construction carbon steel.

C. Case II Combined Geothermal/Cogeneration Surface System Conceptual Design

1. Process Description

This plant design involves the use of a portion of waste heat from the waste gas incinerator to generate electricity in a back pressure steam turbine. The turbine would exhaust to process at 150 psig. A schematic of the combined geothermal/cogeneration surface system is shown in Figure VI-7. In comparison with the Case I geothermal system design, additional geothermal energy will be used in this process to replace that portion of the waste heat which is used to generate electricity in lieu of process heat. No additional natural gas would be burned to produce the electricity. Comparison of the two conceptual designs show that the cogeneration system would increase the amount of geothermal energy which can be utilized by the equivalent of 7110 lbs/hr of process steam. Less steam is produced because more Btu/lb of steam are required to produce the higher temperatures and pressures for the turbine generator. The geothermal energy is, in effect, displacing some of the electrical energy requirements of the plant. The basic thermodynamic advantage of this concept is that heat is transferred from the high temperature waste heat source to the working fluid at a higher temperature level which is generally more efficient.

As shown in Figure VI-7, the geothermal brine at about 335°F is first pumped to two 20,000 gallon storage tanks, and then it is used to preheat the intermediate loop softened water, and the waste gases to the incinerator. The total amount of geothermal brine required would be 160,157 lbs/hr, of which 130,547 lbs/hr preheat the intermediate loop water up to 325°F, and 29,610 lbs/hr preheat the waste gas stream before entering the incinerator up to 300°F. The hot intermediate loop water at 113,140 lbs/hr and 325°F would then be used to heat the dry air to the starch dryer up to 289°F and the corn steepwater to the evaporator up to 200°F.

Figure VI-7 COMBINED GEOTHERMAL/COGENERATION SYSTEM CONCEPTUAL DESIGN - CASE II

In addition to the geothermal energy used to preheat the dry air to the starch dryer, 2563 lbs/hr of 150 psig saturated steam is used to further preheat the dry air to the starch dryer up to 336°F.

As in Case I, the electrically driven (950 hp) steepwater vapor compression unit will also be replaced by a four effect evaporator preheated by geothermal energy indirectly through the intermediate loop.

The pretreatment of geothermal brine will be the same as in the Case I system, in which the geothermal brine will be kept under pressure, and threshold treatment at 5 ppm will be used to prevent calcium carbonate, sulfate and barium sulfate scaling. In addition, a minimum geothermal brine temperature of 160°F will be maintained to prevent silica precipitation.

2. Piping and Equipment

Figure VI-8 shows the plot plan for the combined geothermal/cogeneration system conceptual design. The geothermal brine piping layout is the same as Case I. The production well is assumed to be 500 feet from the plant and 1000 feet away from the reinjection well. Geothermal brine piping to the plant and reinjection well will be buried. In the plant area, the piping system will be raised 25 feet above the grade so that it will not be an obstacle for access or maintenance. In addition to all the equipment related to the geothermal energy system, a 2 MW turbine, desuperheater and feedwater preheater are included.

(a) Piping

All piping material will be carbon steel. Piping for geothermal brine system will be schedule 80, and piping for softened water will be schedule 40.

LEGEND

- 1 SOFTENED WATER PREHEATER
 - 2 STARCH DRYER DRYAIR PREHEATER
 - 3 STARCH DRYER DRYAIR PREHEATER
 - 4 HEAT RECOVERY SECTION BLOWDOWN COOLER
 - 5 TURBINE GENERATOR
 - 6 DESUPERHEATER
 - 7 FEEDWATER PREHEATER
 - 8 INCINERATOR DRYAIR/WATER VAPOR PREHEATER
 - 9 CORN STEEPWATER PREHEATER
- GEOTHERMAL DRINE PIPING
- REINJECTION DRINE PIPING
- N.T.S. NOT TO SCALE

SCALE

Figure VI-8 COMBINED GEOTHERMAL/COGENERATION SYSTEM
CONCEPTUAL DESIGN PLOT PLANT - CASE II

The wall thickness of geothermal brine piping selection is based on the results from the laboratory and field corrosion tests in East Mesa nonaerated wellhead fluid which indicated corrosion rates of 3.2 mpy to 17.3 mpy.⁽¹⁹⁾

Figures VI-9 and 10 show an isometric sketch of the interconnecting piping at the geothermal brine production wellhead and the reinjection wellhead, respectively.

Figure VI-11 shows an isometric sketch of the interconnecting piping for the geothermal brine and intermediate loop softened water piping systems in the main plant area.

Figure VI-12 shows an isometric sketch steam generation piping system.

Table VI-4 is a piping list which defines the quantity and specifications for all piping used in the Case II plant design.

FIGURE VI-9 GEOTHERMAL BRINE PRODUCTION WELLHEAD PIPING DIAGRAM

FIGURE VI-10 GEOTHERMAL BRINE REINJECTION WELLHEAD PIPING DIAGRAM

FIGURE VI-11 COMBINED GEOTHERMAL/COGENERATION SYSTEM CONCEPTUAL DESIGN PIPING DIAGRAM
MAIN PLANT AREA

FIGURE VI-12 STEAM GENERATION PIPING DIAGRAM

Turbine Superheated Steam
 150 PSIG Saturated Steam
 Feedwater

VI-30

PRELIMINARY ISSUE	ISSUE FOR BID	ISSUE FOR CONSTRUCTION	ZERO ISSUE	0	BRISC APPROVAL	CLIENT APPROVAL
----------------------	------------------	---------------------------	---------------	---	-------------------	--------------------

(b) Equipment

All the equipment that is related to the Case II plant is described in the following paragraphs and is summarized on the equipment list shown on Table VI-5.

(1) Geothermal Brine Pump

The geothermal brine pumps are horizontal type centrifugal pumps with 316 stainless steel casings and impellers and monel shafts. These materials are used due to their corrosion resistance to brine. The pump is rated at 375 gpm and is driven by a 480 volt, 3 phase, 60 hertz motor rated at 30 hp.

(2) Threshold Additive Pump

The two threshold additive pumps are controlled volume simplex-diaphragm plunger pumps with 316 stainless steel heads and check valves and teflon diaphragms. These materials are used due to their resistance to corrosion by the chemical solutions being pumped. Each pump is rated at 3 gph with a flooded suction. Each pump includes a 480 volt, 3 phase, 60 hertz motor rated at 1/4 hp.

(3) Softened Water Pump

The two softened water pumps are horizontal type centrifugal pumps with all 316 stainless steel material. Each pump is rated at 150 gpm. Each pump includes a 480 volt, 3 phase, 60 hertz motor rated at 7 1/2 hp.

(4) Threshold Additives Mixing Tank

The threshold additives mixing tank is a vertical, 316 stainless steel unit and is 42 inches in diameter by 50 inches in height. The top of the tank is flat and is hinged for access to the tank. The capacity of the tank is 250 gallons. An agitator is fitted to the tank for mixing with 316 stainless steel shaft and propeller. The agitator includes a 480 volt, 3 phase, 60 hertz motor rated at 1/4 hp.

(5) Incinerator Dry Air/Water Vapor Preheater

The incinerator preheater is a single pass fin tube type heat exchanger with geothermal brine on the tube side and waste gas on the fin side. The heater used 29,610 lbs/hr of geothermal brine to heat the 88,636 lbs/hr of waste gas to 300°F. The heater has a 37 7/16 inch casing height, an 11 1/2 feet tube length, and is 6 rows deep with a total of 146 tubes. The total heating surface is 18,246.2 ft². The titanium tubes are 5/8 inch OD by 0.035 inch wall thickness. The tube sheets are titanium, the fins are copper solder coated, and the water box headers are carbon steel. The fluid pressure drop is 21.6 feet of water, and the air side loss is 2.14 inch of water.

(6) Starch Dryer Dry Air Preheater

The starch dryer preheater has a 41 5/8 inch casing height, a 12 foot tube length, and is 10 rows deep with a total of 24 tubes. The heater is a single pass, fin tube type heat exchanger with softened water on the tube side and dry air on the shell side. The heater used 58,737 lbs/hr of softened water to heat 194,236 lbs/hr of dry air to 289°F. The total heating surface is 17,846.1 ft². The tubes are copper and the fins are copper solder coated. The headers are carbon steel and the casing is 16 gauge galvanized sheet steel. The water side pressure drop is 12.8 feet of water, and the air side loss is 1.49 inches of water.

(7) Intermediate Loop Softened Water Preheater

The intermediate loop softened water preheater is a plate type heat exchanger. The heater is 9'-3 1/2" long by 1'-11 1/4" wide and 5'-1 1/8" overall height. It is single pass and uses 130,547 lbs/hr of geothermal brine to heat 113,140 lbs/hr of softened water to 325°F. Total surface area is 1444 ft² composed of 352 titanium plates measuring 17 1/2 inches long by 45 inches wide. The heat exchanger frame is carbon steel and is lined with a corrosion resistant epoxy paint.

(8) Steepwater Evaporator

The steepwater evaporator is a plate type quadruple effect evaporator. The first three effects operate on a single pass, rising and falling film principle, and the fourth effect is a forced circulation design plate type heat exchanger. The plates are 316 stainless steel and the frames are carbon steel. The

first three effects consist of a total of 172 plate units and 3526 ft². The fourth effect consists of 4 passes with 320 plates and a total surface area of 2400 ft². The overall dimension is 40 feet long by 24 feet wide and 20 feet high.

(9) Heat Recovery Section

The heat recovery section is a shell and tube type heat exchanger which generate superheated steam. The unit is rated at a maximum capacity of 70,000 lbs/hr at 850 psig and 825°F.

(10) Geothermal Brine Production Well Storage Tank

The two geothermal brine production well storage tanks are horizontal, carbon steel vessels 10 feet 6 inches in diameter by 31 feet in length. The heads of the vessel are ellipsoidal dished. Each vessel has a capacity of 20,000 gallons. The interior surface of the vessel is lined with an epoxy phenolic coating to protect the carbon steel shell from the corrosive effects of the hot geothermal brine. The exterior surface of the vessel has 4 inches of insulation with a weather-proof jacket. Each vessel is rated at 150 psi.

(11) Reinjection Brine Storage Tank

The reinjection brine storage tank is a horizontal, carbon steel vessel, 10 feet 6 inches in diameter by 15 feet 6 inches in length. Both heads of the vessel are ellipsoidal dished. The vessel has a capacity of 10,000 gallons. The interior surface of the vessel is lined with an epoxy phenolic coating to protect the carbon steel shell from the corrosive effects of the hot geothermal brine.

(12) Steam Turbine Generator

The steam turbine generator is 23 feet long by 9½ feet wide and 7 feet overall height. The rated capacity is 2 MW. Theoretical steam rate is about

26 lb/kWh. The steam enters the turbine at 825°F and 850 psig and exhausts at 150 psig and 530°F.

(13) Desuperheater

The desuperheater is sized at 8 inch ID for the steam inlet and 1/2 inch ID for the water inlet. The overall length is 41 inches. The desuperheater reduces the turbine exhaust steam temperature from 530°F to 366°F at 150 psig.

(14) Feedwater Heater

The feedwater heater is a shell and tube type heat exchanger. It is single pass and uses 5,235 lb/hr of steam to heat 59,781 lb/hr of softened water to 340°F. Total heating surface is 220 ft². The heater shell is carbon steel, and the tubes are 304 stainless steel.

Table VI-4 Piping List - Case II

<u>Service</u>	<u>Qty.</u>	<u>Description</u>
1. Geothermal Brine From Production Well	721 ft.	4 inch OD, sch. 80 with fiberglass insulation
2. Geothermal Brine From Production Well	219 ft.	2 1/2 inch OD, sch. 80 with fiberglass insulation
3. Geothermal Brine to Reinjection Well	235 ft.	2 1/2 inch OD, sch. 80 with fiberglass insulation
4. Geothermal Brine to Reinjection Well	74 ft.	4 inch OD, sch. 80 with fiberglass insulation
5. Geothermal Brine to Reinjection Well	1535 ft.	4 inch OD, sch. 80
6. Softened Water	25 ft.	4 inch OD, sch. 40
7. Softened Water	149 ft.	3 inch OD, sch. 40
8. Softened Water	509 ft.	2 1/2 inch OD, sch. 40

Table VI-5 Major Equipment List - Case II

<u>Service</u>	<u>Qty.</u>	<u>Description</u>
1. Geothermal Brine Pump	1	Horizontal type centrifugal pumps rated at 375 gpm and 30 hp motor. Materials of construction are 316 ss casing and impeller while the shafts are monel.
2. Threshold Additives Pumps	2	Controlled volume, simplex-diaphragm plunger type. 3 gph max. flow, 1/4 hp motor and flooded suction. Stainless steel body and teflon diaphragm.
3. Softened Water Pumps	2	Horizontal, centrifugal pump. 150 gpm flow. 7 1/2 hp motor. Materials of construction are cast iron body, bronze impeller and 316 stainless steel shafts.
4. Threshold Additives Mixing Tank	1	Vertical tank, 250 gallon capacity, 42 inches in diameter, 50 inches overall height, with flat, hinged top. Stainless steel construction.
5. Threshold Additives Agitator	1	Stainless steel propeller and shaft agitator with clamp for connection to mixing tank. 1/4 hp motor.
6. Incinerator Dry Air/Water Vapor Preheater	1	Single pass fin tube type heat exchanger. 37 7/16 inches casing height by 11 1/2 feet tube length. Titanium tubes and copper solder coated fins.
7. Starch Dryer Dry Air Preheater	1	Single pass fin tube type heat exchanger. 41 5/8 inches casing height by 12 feet tube length copper tubes and copper solder coated fins.
8. Softened Water Preheater	1	Plates type heat exchanger. Carbon steel frame with titanium plates. Total heating surface area is 1444 FT ² . Overall dimensions are 9' 3 1/2" L x 5' 1 1/8" H x 1' 11 1/4" W.

<u>Service</u>	<u>Qty</u>	<u>Description</u>
9. Steepwater Evaporator	1	Quadruple plate type effect evaporator. Overall dimensions are 40 feet long by 24 feet wide and 20 feet high. Material of construction are 316 stainless steel plates and carbon steel frames. Total surface area is 5926 ft ² .
10. Heat Recovery Section	1	Shell and tube type heat exchanger. Generate 70,000 lb/hr of 850 psig and 825°F superheated steam.
11. Geothermal Brine Production	2	Horizontal tank, 20,000 gallons capacity, 10 feet 6 inches in diameter by 31 feet long. Material of construction is carbon steel.
12. Reinjection Brine Storage Tank	1	Horizontal tank, 10,000 gallons capacity, 10 feet 6 inches in diameter by 15 feet 6 inches long. Material of construction is carbon steel.
13. Steam Turbine Generator	1	2 MW, 23 feet long by 9½ feet wide and 7 feet overall height.
14. Desuperheater	1	Steam inlet 8 inch ID, water inlet ½ inch ID, and overall length at 41 inches.
15. Feedwater Heater	1	Shell and tube type heat exchanger. Total heating surface area at 220 ft ² .

3. Energy Utilization

The total process energy requirement for the combined/cogeneration system conceptual design includes 76.2×10^6 Btus/hr of natural gas to the incinerator, 2.6×10^6 Btus/hr of natural gas to the starch dryer and 7040 kWh/hr of electrical energy.

The combined/cogeneration system conceptual design involves the use of a portion of the waste heat from the waste gas incinerator to generate electricity in a back pressure steam turbine. The turbine would exhaust to process at 150 psig.

Due to the use of geothermal energy, the Case II plant uses about 7.8×10^6 Btus/hr less natural gas than the base plant, and 2.2×10^6 Btus/hr less than Case I.

The electric power consumption for the entire plant is 7040 kWh/hr in both Case I and II. However, in Case II, the generation of 2060 kW of electric power by the in-plant equipment reduces the amount to be purchased to 4980 kWh/hr. This is a net savings of 2520 kWh/hr when compared to the base plant and 1985 kWh/hr compared to Case I.

The use of geothermal energy in Case II plant is 20.4×10^6 Btu/hr. This compares to 14.7×10^6 Btu/hr in Case I plant.

VII. OPERATING COST ESTIMATES and ECONOMIC ANALYSIS

A. General Approach

The objective of this analysis was to assess the economic viability of constructing a Wet Corn Milling Plant at East Mesa, similar to the Corn Products Plant at Stockton, California, to utilize geothermal resources. A discounted cash flow rate of return (DCFRR) analysis technique was used to evaluate the economics of the new plant. The cash flow analysis compared the future annual expenditures required from the owner in order to operate with geothermal energy sources, for both a geothermal design and a combined geothermal/cogeneration design, and for a cogeneration only design, versus those expenditures required if he maintained the design of the Stockton Plant.

A separate DCFRR analysis was performed for a total of twenty-seven cases. Each case was defined in terms of a specific combination of fuel escalation rates and capital costs for the three plants designs. The analysis sheet for one case is included in Appendix E for illustrative purposes. All cases were calculated using a computer program, and these output sheets are also included in Appendix E.

The DCFRR analysis was performed on the basis of the difference in capital and operating costs between the geothermal and cogeneration plant cases and the conventional, or "base," plant case. Thus, it was only necessary to consider those equipment and operating costs that differed in the base plant and geothermal or cogeneration plant cases and only these differences were considered in the calculation. These items are discussed in more detail below.

The reduction in annual natural gas costs due to the use of geothermal energy was considered as a "revenue" or positive cash flow. The annual expenditures

or negative cash flows are used in this study included: property taxes, insurance, maintenance (materials and labor), chemicals and annual income taxes. The computer program used to perform the analysis had been set up to consider electric power consumption as an annual expenditure or negative cash flow. However, in the current geothermal application, electric power is a revenue or positive cash flow compared to the base case because of the elimination of the mechanical vapor recompression steepwater evaporators in both geothermal cases, and because of the electrical generation in the cogeneration case. Therefore, in applying the computer group program, electric consumption was entered as a negative quantity to convert, internally to the program, from an expenditure to a revenue.

The net cash income for each year was the algebraic sum of all cash flow excluding income tax. For income tax purposes, deductions were made from the net cash income for intangible drilling costs and straight-line depreciation in order to get the taxable income. The intangible drilling cost deduction applied only in the first year of the project. The annual income taxes were then determined by multiplying the taxable income by a rate of 48.6% (considered to be a representative corporate rate). For the first year of operation only, the tax burden was reduced by subtracting the investment tax credit and the alternative energy tax credit. The income tax was then added algebraically to the net cash income to obtain the annual net cash flow.

The methods and assumptions used to determine the income tax deductions and credits discussed above will be described later. It should be noted here, however, that the net result of these deductions and credits generally was a

net reduction in income taxes (i.e. a positive cash flow or "revenue") for the first year of the project (see Appendix E) which, when added to the net cash income, yielded a relatively large net cash flow for that year.

The annual discounted cash flow is simply the product of the discount (or present worth) factor and the annual cash flow.

The net present value is the algebraic summation of the discounted net cash flows for all years of the project life. The discount rate for which the net present value equals zero is the equivalent rate for return. This is determined through an iterative procedure which was performed by the BRISC computer program. A listing of this program is included in the Appendix.

Project Time Frame

For purpose of the DCFRR analysis, it was necessary to assume dates for project start, plant start-up, and total operating life. Therefore, it was assumed that plant start-up would be on June 1, 1981 and that well drilling and major equipment contracts would be let during the fourth quarter of 1980. A 20-year operating life was assumed for all cases.

Capital Costs

The capital cost estimates are based on the inclusion of the following major items:

1. Civil Work - All excavation, backfill, concrete, structural steel, building construction, foundations and pipe support.
2. Machinery and Equipment - All major pieces of equipment, pumps, storage tanks, evaporators, heat recovery section and preheaters.
3. Piping Systems - All major piping, filterings, valves, expansion joints, insulation (2" thick with all weather jackets) and pipe hangers.

4. Electrical System - Wiring, cable, cable trays, motor control centers, motors, electric appliances and equipment connections.
5. Instrumentation - All instruments, instrument tubing, wiring and control panels.
6. Well - Geothermal brine production and reinjection well.

Table VII-1 shows the major pieces of equipment that are included in the estimate for the base plant, for the Case I plant and for the Case II plant. The table only shows the equipment which must be added or modified relative to the base plant. The equipment listed under the base plant is that which was modified in Case I and/or II.

Cost estimates were also developed for the addition of a cogeneration system only to the base plant. This arrangement was identified as Case III, and was made in order to assess the relative contributions of the geothermal system and the cogeneration system to the rate of return for Case II. The Case III arrangement was basically the same as Case II, except that in Case III more natural gas would be burned in the incinerator so that the quantity of high pressure steam produced would match the base plant 150 psig process steam production.

TABLE VII-1 MAJOR EQUIPMENT INCLUDED IN CAPITAL COST ESTIMATES

<u>Base Plant</u>	<u>Case I - Geothermal Conceptual Design</u>	<u>Case II - Combined Geothermal/Cogeneration Conceptual Design</u>
Starch Dryer Preheater	Starch Dryer Preheater	Starch Dryer Preheater
Mechanical Vapor Recompression Steepwater Evaporator	Thermo Vapor Recompression Steepwater Evaporator	Thermo Vapor Recompression Steepwater Evaporator
Heat Recovery Section	Heat Recovery Section	Heat Recovery Section
	Incinerator Preheater	Incinerator Preheater
	Softened Water Preheaters	Softened Water Preheaters
	Softened Water Pumps	Softened Water Pumps
	Threshold Feed System	Threshold Feed System
	Geothermal Brine Process Pump	Geothermal Brine Process Pump
	Geothermal Brine Production Well Pump	Geothermal Brine Production Well Pump
	Geothermal Brine Reinjection Well Pump	Geothermal Brine Reinjection Well Pump
	Geothermal Brine Production Well	Geothermal Brine Production Well
	Geothermal Brine Reinjection Well	Geothermal Brine Reinjection Well
	Geothermal Brine Storage Tanks	Geothermal Brine Storage Tanks
	Geothermal Brine Surge Tank	Geothermal Brine Surge Tank
	Piping and Fittings	Piping and Fittings
	Electrical	Turbine Generator
	Instrumentation	Electrical
	Civil Work	Instrumentation
	Sheds at Geothermal Brine Wells	Civil Work
		Sheds at Geothermal Brine Wells
		Building for Turbine Generator

The estimates also include the cost of construction equipment needed for installation of plant equipment and machinery, i.e., cranes, hoists and tractors. Not included in the estimates are costs for land, a spare parts inventory and temporary housing for construction workers. A ten percent contingency factor has been applied to the final equipment capital costs to cover unexpected events.

A summary of the total capital cost estimates based on the major equipment list on Table VII-1 is as follows:

	<u>Base Plant</u>	<u>Case I-Geothermal Conceptual Design</u>	<u>Case II-Combined Geothermal/ Cogeneration Conceptual Design</u>
Building		\$ 5,465	\$ 20,656
Mechanical Equip. \$ 1,473,725		\$ 1,664,640	\$ 2,219,129
Electrical -		\$ 119,600	\$ 269,600
Instrumentation -		\$ 16,000	\$ 16,000
Geothermal Wells -		\$ 1,570,000	\$ 1,570,000
Total \$ 1,473,725		\$ 3,375,705	\$ 4,095,385
Differential Cost Base		\$ 1,901,980	\$ 2,621,660

The cost estimates for Case III were conservatively approximated based upon comparisons between Cases I and II. The incremental capital cost for Case III relative to the base case was \$720,000.

As mentioned earlier, the differential capital costs between the geothermal and/or cogeneration plants and the base plant case were used in the DCFRR calculation. These costs are as of the first quarter of 1980. These were increased by 5 percent to account for escalation to the fourth quarter of 1980 (i.e. 10 percent per year for a half year). The escalated fourth quarter values are shown on the Cash Flow Analysis Sheets in Appendix E.

Based on telephone conversation with DOE, it was assumed for this study that the alternative energy tax credit would not apply to buildings. In order

to simplify the calculations, the reasonably conservative assumption was made that for each case, the "building" cost would include all of the Civil/Structural costs shown on the Capital Cost Estimate Summary Sheets in Appendix A, B and C.

Capital costs for the geothermal production and reinjection wells were based upon several cost estimates (See Section VI-A). These estimates, escalated by 5 percent to the fourth quarter of 1980, along with the other capital cost estimates, were used in calculating the economics for each design case. These capital costs were subsequently varied in a sensitivity analysis, as discussed later.

Annual Natural Gas Cost Savings

Table VII-2 presents operating data for the geothermal and base design cases. Total annual natural gas usage is shown for each case, for that equipment affected by the geothermal application assuming 7,884 hours operation per year. Natural gas cost savings were based upon the difference in annual usage between the appropriate case and the base plant.

The Case III plant would consume 169 cfm more natural gas than the base plant. For this case, therefore, the annual natural gas savings was inputted to the computer program as a negative quantity to treat it as an expense rather than a savings.

The current natural gas cost used in the analysis was obtained from Corn Products. The future escalation rates were estimated from past trends (20). The average industrial price of natural gas was shown to have increased by 24 percent between January 1979 and January 1980. From this, conservatively, an escalation rate of 20 percent was assumed for the next five years, with a subsequent escalation rate of 10 percent. The resulting natural gas costs are:

<u>Date</u>	<u>Escalation Rate, Percent/Year</u>	<u>Unit Cost, Dollar/MMBTU</u>
January 1980		3.80
January 1981	20%	4.56
January 1982	20%	5.47
January 1983	20%	6.57
January 1984	20%	7.88
January 1985	20%	9.46
January 1986 - End of Project	10%	

Annual Electric Energy Cost Savings

Geothermal system power requirements and annual electric energy consumption for each case are also shown in Table VII-2.

The specific capacity of the geothermal well is defined as follows:

$$\text{Well Specific Capacity} = \frac{\text{Well Output, gpm}}{\text{Well Drawdown, ft}}$$

The drawdown is a measure of the head which must be provided by the well pump to overcome the flow resistance of the aquifer and the well. In this analysis, it was assumed that the drawdown for the production well and for the reinjection wells were equal. For case I, the drawdown head was taken as 500 ft. The geothermal flow for case II is about 38 percent greater than for case I. Since drawdown is directly proportional to flow, the drawdown head for case II was taken as 690 ft. The head developed by the downhole pump was, therefore, taken as 500 ft. for case I and 690 ft. for case II. Power requirements for the geothermal fluid pumps were based upon these heads and the required flows, using pump and motor efficiencies provided by suppliers for downhole and reinjection pumps.

Additional power is required to overcome the surface system head losses. These requirements were met by individual pumps at the surface.

The total electric energy consumption for each case was calculated by multiplying the individual power requirements by 7,884 hours per year. The results for each case, for all geothermal related pumps, are shown in Table VII-2.

Replacing the vapor recompression steepwater evaporator of the base case with thermal units result in a reduction in electrical consumption for cases I and II. Additionally, case II generates 2060 KW of electricity, while case III generates 2318 KW for a further reduction in net electrical consumption. As a result, the electrical consumption of case I, II and III represent cost savings over that of the base case. This cost savings is taken into account in the computer calculation by inputting the electrical consumption as a negative quantity.

The unit cost for electricity used in this analysis was also obtained from Corn Products. The escalation rate for subsequent years was also based upon data in reference (20). This shows a 17 percent increase in electricity rates between January 1979 and 1980 for industrial users and an overall average of 159. for the same period for all users. From this, conservatively, electrical rate escalation has been taken as 15 percent for the next five years, with a subsequent escalation rate of 10 percent. The resulting electricity cost are:

<u>Date</u>	<u>Escalation Rate, Percent/Year</u>	<u>Unit Cost, Dollar/kWh</u>
January 1980		.0376
January 1981	15%	.0432
January 1982	15%	.0497
January 1983	15%	.0572
January 1984	15%	.0658
January 1985	15%	.0756
January 1986 -End of Project	10%	

Annual Property Tax and Insurance Cost

The annual costs for taxes and insurance for the first year of operation were estimated to be 2 percent of the total project capital cost for each case, based upon general industrial trends. The first year cost was then escalated at 10 percent per year throughout the project life.

Annual Maintenance Cost

Reference (21) presents service lives and maintenance frequencies for carbon steel domestic, irrigation, and municipal wells in various aquifers in 10 groundwater regions across the nation. Using an economic model based on performance data for metal pipes in corrosive fluid service, that study predicated the lives and maintenance frequencies of geothermal wells relative to conventional water wells. From this, it is anticipated that an expenditure of 10 percent of the replacement cost may be required every three to four years for well maintenance. An expenditure of 10 percent every three to four years is equivalent to about three percent per year for the wells.

For surface equipment of the type included in the geothermal system, annual maintenance costs are generally estimated to range from two to five percent of the capital cost.

On the basis of these figures, it was decided to use a first year annual maintenance cost (materials and labor) of three percent of the total capital cost for each geothermal case. This cost was then escalated by ten percent year to get values for the remainder of the project life.

Annual Chemical Costs

As a result of the consideration of geothermal brine chemistry, as discussed earlier, threshold additive treatment was judged to be the effective means of

scale control. The threshold chemical requirements were estimated and the quantities are shown in Table VII-2. From this, chemical costs were determined, based on first quarter 1980 prices in various chemical price lists. This cost was then escalated by ten percent per year to get the cost for each year of the plant operating life.

Intangible Drilling Costs

In order to estimate what percentage of the total drilling costs would be classed as intangible for income tax purposes, an analysis was made of the estimated cost breakdown provided in another study⁽²²⁾. This analysis is summarized in Table VII-3. The basic philosophy in the analysis was to consider the costs for all materials which could theoretically be removed from the well and reused as tangible costs. All other costs were intangible. The results of this analysis showed that 70 percent of the total well cost could be considered as intangible drilling cost. Therefore, this figure was used to determine the intangible drilling cost deduction for the year in which the well was completed. It was assumed that although well costs of Table VII-3 might differ from costs in the present study, the ratio of tangible costs to intangible costs would remain unchanged. For this analysis it was assumed that the tax reduction (i.e., positive cash flow) due to this deduction would occur in the first year of operation.

Tax Credits

This analysis also assumed that the Alternative Energy Tax credit would be applied during the first year of operation. It was assumed that this deduction would be equal to 15 percent of the sum of the tangible well costs plus the total surface system cost minus the cost of buildings.

In addition to the Alternative Energy Tax Credit, an Investment Tax Credit was also assumed during the first year of operation. This credit was 10% of the total project capital cost.

B. Sensitivity Analysis

Runs were made to assess the sensitivity of the economic analysis results to variations in capital cost and natural gas escalation rates.

Capital cost, of the geothermal wells in particular, comprise an area of uncertainty in the geothermal applications. Computer runs were made to calculate how the rates of return and payback periods were affected by a change of ± 25 percent in capital costs, which was considered a reasonable range given the level of detail to which this study was carried out. In calculating values for the new curves, costs for taxes, insurance, maintenance, etc. were also increased since they were estimated as percentages of capital cost.

As indicated by experience of recent years, prediction of natural gas escalation rates with any degree of certainty is extremely difficult. The best estimate escalation schedule for this analysis was described earlier in this section, and was equal to 20 percent per year through 1985 and 10 percent per year after that. In order to test the sensitivity of the analysis results to escalation rates, calculations were made for two additional escalation schedules. The first, as a lower limit, assumed no escalation of any cost items. For this case, natural gas, electricity, taxes and insurance, maintenance and chemicals were all maintained at their initial values throughout the life of the plant. In the second case, natural gas escalation rates were assumed to increase by 50 percent over the best estimate case, i.e., at a rate of 30 percent per year through 1985 and at a rate of 15 percent per year thereafter.

TABLE VII-2

Operating Data

<u>Base Plant</u>	<u>Case I -Geothermal Conceptual Design</u>	<u>Case II -Combined Geothermal/ Cogeneration Conceptual Design</u>
1. Natural Gas Starch Dryer 101.3 CFM Incinerator 1274 CFM Total 1373.3 CFM ¹⁰ BTUS/yr. 68.31×10^{10}	1. Natural Gas Starch Dryer 76.6 CFM Incinerator 1210 CFM Total 1286.6 CFM ¹⁰ BTUS/yr. 63.904×10^{10}	1. Natural Gas Starch Dryer 41.6 CFM Incinerator 1210 CFM Total 1251.6 CFM ¹⁰ BTUS/yr. 62.166×10^{10}
2. Electric Power Steepwater Evap. 708.4 KW at 950 Hp Others 6791.6 KW Total 7500 KW Purchased	2. Electric Power Steepwater Evap. 85 Hp Threshold Pump 1/2 Hp Soft. Water Pump 7 1/2 Hp Geo. Brine Production Well Pump 47 Hp Geo. Brine Process Pump 30 Hp Geo. Brine Reinjection Well Pump 63 Hp Sub Total 232.75 Hp 173.5 KW Others 6791.6 KW Total Purchased 6965 KW	2. Electric Power Steepwater Evap. 85 Hp Threshold Pump 1/4 Hp Soft. Water Pump 7 1/2 Hp Geo. Brine Production Well Pump 90 Hp Geo. Brine Process Pump 30 Hp Geo. Brine Reinjection Well Pump 120 Hp Sub Total 332.75 Hp 248.1 KW Others 6791.6 KW Total 7040 KW Cogeneration 2060 KW Net Total Purchased 4980 KW
	3. Chemicals Threshold Additives 0.58 lb/hr	3. Chemicals Threshold Additives 0.8 lb/hr

C. Results of Analysis

Appendix E contains a Cash Flow Analysis Sheet for one of the cases defined earlier. The one case is shown as an example of the computer calculations. The computer output for all the cases is presented in Appendix E. In addition, some of the key results are presented graphically in this section.

Figure VII-1 presents the after tax rate of return and the after tax payback period for geothermal design cases I, II and III for the best estimate natural gas initial inflation rate of 20 percent. Rate of return and payback period are each shown as a function of capital cost, with a $\pm$ 25 percent deviation from the best estimate capital cost.

Figure VII-2 presents the after tax rate of return and the after tax payback period for the case I geothermal plant as a function of capital cost, for the best estimate inflation rates, for a natural gas inflation rate increased by 50%, and for today's costs without escalation of fuel or other costs. Figures VII-3 and VII-4 show the same information for the case II geothermal/cogeneration plant and the case III cogeneration only plant, respectively.

The results indicate that for the best estimate capital costs and natural gas escalation rates the case I geothermal plant shows an after tax rate of return of 28 percent with an after tax payback period of 3.8 years, while the case II plant shows an after tax rate of return of 46.1 percent with an after tax payback period of 2.2 years. The rates of return and payback periods for case III are nearly equal to that for case II.

TABLE VII-3
Estimate of Intangible Drilling Costs

<u>Tangibles</u>	<u>Gruy</u>	<u>D'Appolonia</u>
Tubulars	\$196,000 <u>138,000</u>	\$ 85,000 <u>85,000</u>
	\$334,000	\$170,000
Pump (modified cost)	<u>53,000</u>	<u>53,000</u>
TOTAL TANGIBLES	\$387,000	\$223,000
Total Tangible and Intangible	\$1,166,000	\$ 800,000
Pump Adjustment	- \$129,000+53,000 = -76,000	-\$10,000+53,000 = +43,000
Pump Test Adjustment	+35,000	—
Total Adjusted	\$1,125,000	\$ 843,000
Tangible Drilling Cost/Total Cost Ratio	0.34	0.26
Intangible Drilling Cost/Total Cost Ratio	0.66	0.74
Average Intangible Cost/Total Cost Ratio		0.70

Figure VII-1

CASE I

GEOTHERMAL ONLY

FRACTION OF BEST-ESTIMATE CAPITAL COST

CORN PRODUCTS, EAST MESA, CALIFORNIA

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-2

CASE II

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-3

CASE III

COGENERATION ONLY

Geothermal Project After Tax
Rate of Return and Payback

Figure VII-4

VIII. REFERENCES

1. Case History Report on East Mesa and Cerro Prieto Geothermal Fields, Los Alamos Scientific Laboratory, June 1979, LA-7889-MS.
2. Geothermal Resource Investigations, East Mesa Test Site, Status Report, Bureau of Reclamation, April 1977.
3. Geothermal Resource Investigations, East Mesa Test Site, Concluding Report, Bureau of Reclamation and Coury and Associates, Inc., September 1979.
4. Geothermal Resource and Reservoir Investigations of U.S. Bureau of Reclamation Leaseholds at East Mesa, Imperial Valley, California, Lawrence Berkeley Laboratory, October 1978, LBL-7094.
5. Morris, CW and Campbell, DA, Geothermal Reservoir Energy Recovery: A Three-Dimensional Simulation Study of the East Mesa Field, 54th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, September 1979.
6. Assessment of Geothermal Resource of the United States - 1978, Geological Survey Circular 790, United States Department of the Interior.
7. Using Geothermal Energy for Power, Power, Vol. 123, No. 10, October 1979, pp. 37-43.
8. Personal Correspondence with Ken Newman, WESTEC Services, Inc., San Diego, CA.
9. Regional Systems Development for Geothermal Energy Resources, Pacific Region (California and Hawaii), Task 2 - Regional Program Monitoring and Progress Evaluation. Topical Report, March 19, 1979, DOE/ET/28432-2, System Development Corporation, Santa Monica, CA.
10. Personal Communication with Brian Boswell, WESTEC Services, Inc., San Diego, CA.
11. Personal Communication with Virgil Welch, Republic Drilling, El Centro, CA.
12. Personal Communication with Debra Struhsacker, Earth Science Laboratory, University of Utah Research Institute, Salt Lake City, UT.
13. Chappell, RN, et al, Geothermal Well Drilling Estimates Based on Past Well Costs, Geothermal Resources Council, Transactions, Vol. 3, September 1979.

14. Lund, JW, et al, Klamath Falls Geothermal Heating District, Geothermal Resources Council, Transactions, Vol. 3, September 1979.
15. Use of Geothermal Heat for Sugar Refining, May 1977, DOE/SAN/1317-3; TRW System and Energy, Redondo Beach, CA.
16. Romney, EM, et al, Baseline Studies in the Desert Ecosystem at East Mesa Geothermal Test Site, Imperial Valley, CA, University of California, September 1977.
17. Regional System Development for Geothermal Energy Resources, Pacific Region (California and Hawaii), Task 1 - Implementation Plan Development. Topical Report, March 26, 1979, DOE/ET/28432-1, System Development Corp., Santa Monica, CA.
18. Scale Inhibition in Geothermal Operations - Experiments with Dequest 2060 Phosphonate in Republic's East Mesa Field, June 1979, Earth Sciences Division, Lawrence Berkeley Laboratory, University of California, Berkeley, DOE/LBL-9089/Gremp 5/UC-66a.
19. Material Selection Guidelines for Geothermal Power System, September 1978, DOE/ALO-3904-1, Radian Corporation, Austin, TX.
20. Energy User News, Fairchild Publications, New York, Recent 1980 issue.
21. Gass, TE, Purdin, WH, Armitage, DM, "Economic Impact of Using Nonmetallic Materials in Low to Intermediate Temperature Geothermal Well Construction - Volume I" National Water Well Association for Brookhaven National Laboratory, December 1979.
22. Direct Application of East Coast Geothermal Resources in a Frozen Food Plant, Final Report, June 1980. Burns and Roe Industrial Services Corporation and Campbell Soup Company.

APPENDIX A

CAPITAL COST ESTIMATE - BASE CASE

Page _____ of _____

[illegible]

APPENDIX B

DETAILED CAPITAL COST ESTIMATE - CASE I

Location PARAMUS

Estimate Sheet

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 1 of 1
Project GEO-THERMAL H.W. SYSTEM	Est. by C. P. OSTROSKY		Ext. Chk'd. by	
Location EAST MESA, CALIF.	Discipline		Approved by	

Description		GENERAL Summary CASE I		ESTIMATED COST		Total Amount	
Account No.	Description			MATERIAL	LABOR		
	MECHANICAL			1,670	105		
	ELECTRICAL			119	600		
	INSTRUMENTATION			16	000		
	TOTAL			1,805	705		
LABOR RATES BASED ON RICHARDSON CONST. COST TREND REPORTER FITTER LOS ANGELES \$18.33 PLUS 67% PM. = \$19.00 NOTE: MECHANICAL & ELECTRICAL PRICING BASED ON RICHARDSON RAPID SYSTEM VOL. II DATED 1980 WITH SOME DEVIATIONS FOR JOB CONDITIONS TOTAL THIS SHEET							

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 3 of

I.O. <u>4862.01</u>	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u>5-21-80</u>	Sheet <u>1</u> of <u> </u>
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chkd. by
Location EAST MESA, CALIF.			Discipline MECHANICAL	Approved by

Description		CASE I		ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	Min/Unit	Min's	Rate*	Cost			
	Geo-thermal BRINE PROCESS PUMP. 30HP.	1	ea	8500	8500	20	20	19	380			8880
	Geo-thermal BRINE REINJECTION Well Pump	1	ea	32000	32000	20	20	1	380			52380
	START-UP.				1000	10	10		190			1190
	THRESHOLD ADDITIVES METERING Pump. 1/4HP.	2	ea	860	1720	3.0	6		114			1834
	THRESHOLD ADDITIVE TANK 250GAL. - Agitator 1/4HP	1	ea	4950	4950	1.5	2.		38			4988
	SOFTWATER PUMPS. 7.5 HP.	2	ea	7340	14680	1.5	3-		57			14737
	HEAT RECOVERY SECTION	1	ea	240,000	240,000	→	→		→			240,000
	TOTAL THIS Sheet.				302850				1159			304009

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 4 of

4862.01		Type Estimate BUDGET		Client CORN PRODUCTS INC. EAST MESA, CALIF.				Date 5-21-80		Sheet 2 of <u> </u>		
ct GEO-THERMAL H.W. SYSTEM								Est. by C. P. OSTROSKY		Frt. Cnt'd. by		
tion EAST MESA, CALIF.								Discipline		Approved by		
ription EQUIP. CONT.		CASE I		ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	INCINERATOR PRE-HEATER	1	ea	41000	41000	4.0	4	19	76		41000	
	DRY AIR PREHEATER @ STARCH DRYER	2	ea	19200	19200	4.0	4		76		19276	
	SOFT WATER PREHEATER @ DECAERATOR	1	ea	3500	3500	2.0	2		38		3538	
	PIPING at Storage TANK (See sheet 4A)			12490	12490				9672		22162	
	SOFTENED WATER Preheater (Plates)	1	ea	47100	47100	4.0	4		76		47176	
	STEEP WATER EVAPORATOR	1	ea	602200	602200	2.0	2		38		602238	
		1	ea			2.0	2		33		735,466	
									9976			

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 4A of

W.O. <u>4862.01</u>	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u>May 21, 80</u>	Sheet <u>1</u> of <u>1</u>
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline <u>mech.</u>	Approved by

Description <u>PIPING @ Storage Tanks.</u>				ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	4" Sch 40 BLK Steel.	180	LF	4.49	808	.23	41	19.	779		
	4" weld Ells.	13	ea	14	182	6.2	81		1539		
	4 " Tees.	3	"	33	99	9.3	28		532		
	4" Gate Valve flgd.	12	"	489	5868	2.0	24		456		
	4" Check "	3	"	491	1473	2.0	6		114		
	4" Control "	1	"	520	520	2.0	2		38		
	4" Flanges	34	"	18	612	1.9	65		1235		
	4" B/g. Sels.	34	"	7.38	251	1.15	39		741		
	4" INSULATION	220	LF	7.50	1650	1.05	231		4389		
	TEST.	180	LF	1.15	27	1.05	9		171		
	PIPE Supports	4	ea	250	1000	5	20		380		
	TOTAL THIS SHEET				12490				9672	22	162

*Composite Rate - Based on Type of Work

BR5201 (2/76)

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT

Location PARAMUS
Estimate Sheet

Page 5 of

O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 3 of <u> </u>
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Est. Checked by
Location EAST MESA, CALIF.			Discipline	Approved by

EAST MESA, CALIF.												
Description	CASE I			ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	Min's	Rate*	Cost			
	CRANE RENTAL	5	week	1600	8000	8	40	19	760			8760
	PLANT-START-UP.	5	Days	1000	5000	8	40	19	760			5760
	BUILDING Sheds 22x24											
	AT Wells											
	144 sq ft. each.	288	SF.	15	4320							4320
	STORAGE TANK	2	EA	10,000	20000	10	20	19	380			20380
	20000 Gal. Cap.											
	STORAGE TANK 10,000 gal.	1	EA	7600	7600	5	5	19	95			7695
	INSULATION. 20,000	40000	S.F.	1-	40000		.50		20,000			60000
	10,000	10000	"	1	10,000		.50		5000			15000
	Concrete work.	246	C.Y	200	36900							36900
	Total. This Sheet.				131820				26995			158815

005001 277

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 6 of

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u>5-21-80</u>	Sheet <u>4</u>
Project <u>GEO-THERMAL H.W. SYSTEM</u>			Est. by <u>C. P. OSTROSKY</u>	Issued by
Location <u>EAST MESA, CALIF.</u>			Discipline <u>MECHANICAL</u>	Approved by

Description				ESTIMATED COST						Contract		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Cost		
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost	Unit Price	Amount	
	PIPE BELOW GRADE.							19				
	4" Sch. 80 BLK STEEL P.E	2060	L.F.	6.51	13412	.007	15		285			13,697
	4" Sch. 80 W. C. LB.	7	EA.	14.-	98	6.2	43		817			915
	4" GATE VALVE. flgd.	2	EA.	489	978	2.1	4		76			1054
	4" Check "	2	EA.	491	982	2.1	4		76			1058
	4" 150# FLANGES	4	EA.	18-	72	1.9	8		152			224
	4" LINE WELDS.	52	EA.	3-	156	1.9	110		2090			2246
	TEST-LINE.	2060	L.F.	.15	309	.005	10-		190			499
	DISTRIBUTION.	2060	L.F.	.10	206	.010	21-		399			605
	WRAP PIPE COATING.	2200	L.F.	.56	1232	.20	44		836			2068
								1				
	TOTAL THIS SHEET				17445				4921			22366

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT

Page 7 of

Location PARAMUS
Estimate Sheet

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u>5-21-80</u>	Sheet <u>5</u> of <u> </u>
Project <u>GEO-THERMAL H.W. SYSTEM</u>			Est. by <u>C. P. OSTROSKY</u>	Ext. Checked by <u> </u>
Location <u>EAST MESA, CALIF.</u>			Discipline <u> </u>	Approved by <u> </u>

Description				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	INSULATION. 2" FIBER - GLASS WITH WATER-PROOF JACKET.								19			
	4" PIPE.	2100	L.F.	7.50	15700	.05	105		1995			17,695
	4" FITTINGS											
	EXCAVATION:											
	2100' x 3' deep & 4' wide:											
	25200 cu. ft. ÷ 27	933	C.Y.	2.50	2332		-		-			2332
	Removal	100	C.Y.	2.00	200		-		-			200
	Road Cut & Removal	110	S.F.	1. -	110		-		-			110
	Rech. Road	110	S.F.	1.50	165		-		-			165
	SITE RESTORATION	8400	S.F.	.10	840		-		-			840
	MISC. BARRIERS, CROSS - OVER Plates, Lights	-	L.S.	200	200		-		-			200
	Total this sheet				19547				1995			21,542

Page 8 of

Estimate Sheet

Description				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	4" Sch. 80 BLK STEEL PIPE	140	L.F.	4.49	629	.23	32	19	608			1237
	2 1/2" " " " "	460	"	3.42	1573	.30	138		2622			4195
	4" Sch. 80 weld Elb	9	ea	14-	126	6.2	55		1045			1171
	2 1/2" " " "	10	ea	650	65-	4.0	40		760			825
	4" " " TEES	2	ea	33	66	9.3	19		361			427
	2 1/2" " " "	1	ea	16	16	6.9	7		133			149
	4"x2 1/2" Conc. Reducers	2	ea.	10-	20	5.4	11		209			229
	4" LINE WELDS	7	ea.	3	21	6.9	48		912			933
	2 1/2" " "	23	ea.	3	69	4.8	110		2090			2159
	4" Gate Valve fig's.	2	ea	489	978	2.	4		76			1054
	2 1/2" " " "	2	ea	420	840	1.2	2		38			878
	4" Check " "	1	ea.	491	491	2.1	2		38			529
	2 1/2" " " "	1	ea	345	345	1.2	1		19			364
	4"-150# W.W. flanges	5	ea	18	90	1.9	10		190			280
	2 1/2" " " "	5	"	12	60	1.2	7		133			193
	Total this Sheet:				5389				9734			14623

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 9 of

W.O. <u>4862.01</u>		Type Estimate <u>BUDGET</u>		Client CORN PRODUCTS INC. EAST MESA, CALIF.				Date <u>5-21-80</u>		Sheet <u>7</u> of <u> </u>	
Project <u>GEO-THERMAL H.W. SYSTEM</u>								Est. by <u>C. P. OSTROSKY</u>		Est. Chkd. by	
Location <u>EAST MESA, CALIF.</u>								Discipline <u>Mechanical</u>		Approved by	

Account No.	Description	Qty.	Unit	ESTIMATED COST						Contract Unit Cost		Total Amount
				Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	<u>PIPING (CONT.) CASE I</u>											
	<u>4" BOLT-GASKETS</u>	<u>6</u>	<u>ea</u>	<u>7.38</u>	<u>44</u>	<u>1.15</u>	<u>7</u>	<u>19</u>	<u>133</u>			<u>177</u>
	<u>2 1/2 " " "</u>	<u>6</u>	<u>"</u>	<u>4.2</u>	<u>25</u>	<u>.57</u>	<u>3</u>	<u>1</u>	<u>57</u>			<u>82</u>
	<u>DISTRIBUTION</u>	<u>600</u>	<u>L.F.</u>	<u>.10</u>	<u>60</u>	<u>.010</u>	<u>6</u>		<u>114</u>			<u>174</u>
	<u>TEST</u>	<u>600</u>	<u>L.F.</u>	<u>.15</u>	<u>90</u>	<u>.005</u>	<u>3-</u>		<u>57</u>			<u>147</u>
	<u>PIPE STANDS 20' High</u>	<u>10</u>	<u>ea</u>	<u>250</u>	<u>2500</u>	<u>5</u>	<u>50</u>		<u>950</u>			<u>3450</u>
	<u>6" PIPE w/ SANO-TUBE</u>											
	<u>BASE.</u>											
	<u>INSULATION</u>											
	<u>2" PIERZ GLASS w/</u>											
	<u>Weather proof JACKET.</u>											
	<u>4"</u>	<u>200</u>	<u>L.F.</u>	<u>7.50</u>	<u>1500</u>	<u>1.05</u>	<u>200</u>		<u>3800</u>			<u>5300</u>
	<u>2 1/2</u>	<u>500</u>	<u>"</u>	<u>5.50</u>	<u>2750</u>	<u>.50</u>	<u>250</u>	<u>1</u>	<u>4750</u>			<u>7500</u>
	<u>TOTAL THIS SHEET</u>				<u>6969</u>				<u>9861</u>			<u>16830</u>

Estimate Sheet

Page 10 of 10

W.O. 4862.01		Type Estimate BUDGET		Client CORN PRODUCTS INC. EAST MESA, CALIF.						Date 5-21-80		Sheet 8 of 8	
Project GEO-THERMAL H.W. SYSTEM										Est. by C. P. OSTROSKY		Ext. Ch'd. by	
Location EAST MESA, CALIF.										Discipline MECHANICAL		Approved by	
Description SOFTENED WATER SYSTEM.				ESTIMATED COST						Contract Unit Cost		Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount		
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost				
	4" Sch 40 Steel Pipe P.E.	25	L.F.	4.45	114	.10	3	19	57			173	
	3" "												

Page 11 of

ESTIMATED COST												
Description									Total Amount			
Account No.	Description	Qty.	Unit	Material		Labor				Contract Unit Cost		
				Cost/Unit	Cost	M/H/Unit	M/H's	Rate*	Cost	Unit Price	Amount	
	4" LINE WELDS	1	ea	3	3	6.9	7	19	133			136
	3 " "	6	"	3	18	5.0	30		570			588
	MISC. FITTINGS-	-	L.S.		110		-		-			110
	TEST-LINE.	370	L.F.	.15	56	.005	3-		57			113
	DISTRIBUTION.	370	L.F.	.10	37	.010	4		76			113
	Misc. Hangers.	-	L.S.		125		-		-			125
	2" FIBER-GLASS INSULATION w/ weatherproof jacket		L.F.									
	4"	30	L.F.	750	225	1.05	31		589			814
	3"	135	L.F.	600	810	.75	101		1919			2729
	1 1/2"	260	L.F.	475	1235	.60	156		2964			4199
	TOTAL THIS SHEET.				2619				6308			8927

Page 12 of

Location PARAMUS
Estimate Sheet

* Comparison to *Hydro* - Effect on Type of Work

Burns & Roe, Inc.
COST ESTIMATING & SCHEDULING DEPARTMENT

Page 13 of

Location
Estimate Sheet

W.O. <u>4862-01</u>	Type Estimate <u> </u>	Client <u>CORN PRODUCTS</u>	Date <u>16/MAY/80</u>	Sheet <u>2</u> of <u>7</u>
Project <u>Geothermal H.W. System</u>			Est. by <u>JVK</u>	Ext. Chk'd. by <u> </u>
Location <u>East Mesa, CA</u>			Discipline <u>Electrical</u>	Approved by <u> </u>

Description				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
1	400A 3P CRT BRK (EXIST. SPNG)	1	EA	4300/EA	4300	48/EA	48					
	4' 50MM CONDUCTIONS	LOT	-	-	20	-	16					
	3 1/2" R.G. STEEL CDT	60'	FT	52 1/4/FT	313	.25/FT	15					
	3 1/2" ELBOWS & COUP	3	EA	21 25/EA	64	4/EA	12					
	PULL BOX	1	EA	125/EA	125	16 EA	16					
	CDT HANGING MATERIAL	ALLOW	LOT		29		4					
	3 1/2" P.V.C	150'	FT	2 10/FT	315	.10/FT	15					
	3 1/2" PVC ELBOWS	2	EA	900 EA	18	2 EA	4					
	THIN CH & BRICK FILL	150'	EA FT	2 50/EA FT	300	1 NC	-					
	3500A + 1A 1/2 GND. TOTAL	750'	FT	2 50/FT	2052	.04 FT	30					
	SWELLING	ALLOW	LOT		100		12					
	GND CONDUIT C.	ALLOW	LOT		350		22					
	THIN CH	1	EA	60/EA	60	16 EA	16					
	500 TO 350 SPLICES	4	EA	5 00/EA	20	3 EA	12					
	500 TO 2/0	4	EA	4 50/EA	18	2.5 EA	10					
	500 TO #12	4	EA	4 00/EA	16	2 EA	8					
	CUTTING & PULL - EXIST SPNG	ALLOW	LOT	-	50	LOT	16					
	ADD FOR SEISMIC HANGING MATERIAL	ALLOW	LOT		250	LOT	32					
	TOTAL				118,430		288					

*Composite Rate - Based on Type of Work

COST ESTIMATING & SCHEDULING DEPARTMENT

Location _____
Estimate Sheet

1862-01		Type Estimate		Client CORN PRODUCTS				Date 10/11/80		Sheet 3 of 7		
Geothermal H.W. System								Est. by JVK		Ext. Chk'd. by		
East Mesa, CA								Discipline Electrical		Approved by		
Description 125 HP GEOTHERMAL PUMP				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	SIZE 5 COMB STARTER	1	EA	3001/EA	3000	32/EA	32					
	4-500MM LINE CONDUIT		LOT		20	4 EA	8					
	4-500MM LAMP CONDUIT		LOT		20	4 EA	8					
	PULL BOX	1	EA	150/EA	150	8 EA	8					
	THROUGH	1	EA	50/EA	50	4 EA	4					
	400F-3P-600V DISC SW	1	EA	285/EA	285	8 EA	8					
	REMOTE P.B. STATION	1	EA	75/EA	75	4 EA	4					
	480V TO 110V 1P TRANSFORMER	1	EA	450/EA	450	16 EA	16					
	FIRKET HP STARTER	1	EA	95/EA	95	2 EA	2					
	30 AMP DISC SW	2	EA	60/EA	120	2 EA	2					
	LIGHTING RECEPT 110V	ALLOW	LOT	-	300	2 EA	80					
	1/4 HP 110 V. MOTOR HOOK UP	2	LOT	20 EA	40	4 EA	8					
	125 HP 480V " " "	1	LOT	50 EA	50	32 EA	32					
	3/4" RIGID CONDUIT	100'	LOT	LOT	69	LOT	8					
	3" " " "	20'	FT	4.25	85	22/FT	4					
	3" " " ELB.	3	EA	17.00/EA	51	4 EA	12					
	3" P.V.C. "	1000'	FT	1.00/FT	1000	108/FT	80					
	3" ELBOW (2) DISC EQUIP	2	EA	8/EA	16	2 EA	4					
	MISC SEISMIC HANGERS				124		16					
	TOTAL - SHEET 3	3			6000		336					

DR-001 (2/7)

Location _____

Estimate Sheet

4862-01		Type Estimate	Client				Date 16/MAY/80		Sheet 4 of 7			
Geothermal H.W. System			CORN PRODUCTS				Est. by JVK		Ext. Chk'd. by			
on East Mesa, CA							Discipline Electrical		Approved by			
125 HP GEOTHERMAL PUMP CONTINUED			ESTIMATED COST							Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
	SHEET # 2				1000		336					
	# 14 THW	5000'	FT	0.058/FT	290	.007/FT	35					
	# 12 THW	500'	FT	0.084/FT	42	.000/FT	4					
	3 # 500 A/C M + 1 # 7/8 GAD-TOTAL	4200'	FT	4.56/FT	19,152	.04/FT	168					
	SUNDRIES				370		17					
	WIRE UP - 110V - 1P 1/4 MARK	1	EN	20	20	2/EN	2					
	" " 750V 125A "	1	EN	50	126	37/EN	32					
	ELECT. HAND HOLS	4	EN	500	2000	11.5/EN	46					
	TOTAL				28000		640					

Estimate Sheet

Page 16 of

4862-01	Type Estimate	Client CORN PRODUCTS	Date 11/may/80	Sheet 5 of 7
Geothermal H.W. System			Est. by JVK	Ext. Chk'd. by
East Mesa, CA			Discipline Electrical	Approved by

[illegible]

Location _____

Estimate Sheet

15

4862-01		Type Estimate		Client				Date		Sheet 6 of 7			
Geothermal H.W. System				CORN PRODUCTS				Est. by JVK		Ext. Chk'd. by			
East Mesa, CA								Discipline Electrical		Approved by			
Description 2- 7 1/2 HP				ESTIMATED COST						Contract Unit Cost		Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price			Amount
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost	Unit Price	Amount		
	SIZE 1 COAR. SPARKER	2	EA	528/EA	1056	6 EA	12						
	LOCK OUT & P.D. STATION	2	EA	75/EA	150	2 EA	4						
	3/4" RIGID CONDUIT	100'	LOT		69	LOT	12						
	3 D. HANGING MATERIAL	ALONG			7		6						
	#14 THIN	500	FT	0.058/FT	29	.007	4						
	#12 THIN	500		0.084	42	.008	4						
	SUPPLIES	ALONG			17		2						
	HOOKEUP- GROUND. START UP & TEST				130		36						
	TOTAL				1500		80						

*Composite Rate – Based on Type of Work

BIR-901 (271C)

COST ESTIMATING & SCHEDULING DEPARTMENT

Page 18 of Location

Estimate Sheet

4862-01

Type Estimate

Client

Date 16/MAY/80Sheet 7 of 7

Geothermal H.W. System

CORN PRODUCTS

Est. by JVK

Ext. Chk'd. by

East Mesa, CA

Discipline Electrical

Approved by

INSTRUMENTATION

ESTIMATED COST

Contract
Unit CostTotal
AmountAccount
No.

Description

Qty.

Unit

Material

Labor

Cost/Unit

Cost

MH/Unit

MH's

Rate*

Cost

Unit Price

Amount

Hook up control panel

FBD

16

H14 & H12 conn

11

8

Control Bins

Align

10

20

10

Buses

10

20

20

Flex conduits

30

60

40

3/4" R.G. S. CDT

200 $\cdot \frac{70}{14}$

140

.08

16

Hiring unit

Align - 60

70

10

H14

1000

60

7

H12

100

9

9

Total start up & shutdown

10

29

TOTAL

400

160

W.O. 4862-01
 GLOTHER MP & H.W. SYSTEM
 FIRST FRESH - C.A.

CLIENT: CORN PRODUCERS

MAY 16, 1980
 J.V.K.
 ELECTRICAL

Page _____ of _____

[illegible]

APPENDIX C

DETAILED CAPITAL COST ESTIMATE - CASE II

Page 19 of

W.O. 4862.01	Type Estimate BUDGET
Project	GEO-THERMAL H.W. SYSTEM
Location	EAST MESA, CALIF.

Client CORN PRODUCTS INC.
EAST MESA, CALIF.

Date 5-21-80	Sheet 1 of 1
Est. by C. P. OSTROSKY	Ext. Chk'd. by
Discipline SUMMARY	Approved by

BR5901 (2/7c)

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 23 of

A.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 1 of 1
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	
Location EAST MESA, CALIF.			Discipline 	
				Ext. Chk'd. by
				Approved by

Description MECHANICAL SUMMARY CASE II			ESTIMATED COST		Total Amount
Account No.	Description		MATERIAL	LABOR	
	SHEET #1 EQUIPMENT.		378 850	1264	380 114
	" #2 "		1054 400	766	1054 666
	" #3 "		154 810	37 503	192 313
	" #4 PIPE BELOW GRADE		17 445	4 921	22 366
	" #5 " " "		19 547	1 995	21 542
	" #6 " ABOVE "		5 389	9 234	14 623
	" #7 " " "		6 969	9 861	16 830
	" #8 SOFTENED WATER		4 592	2 193	6 785
	" #9 " "		4 990	1 463	6 453
	" #10 STEAM PIPE		2 471	1 691	4 162
	" #11 " "		1 765	437	2 202
	TOTAL COST		1,651 228	70 828	1722 056
	INS. TAXES ON LABOR	20%		14 166	14 166
	MOBILIZATION "	10%		7 083	7 083
	RENTALS "	10%		7 083	7 083
	SUPERVISION "	10%		7 083	7 083
	CONTINGENCY (mat labor)	10%	165 123	7 083	172 206
	TOTAL		1 816 351	113 326	1929 677
	OVERHEAD & PROFIT.				289 452
	TOTAL THIS SHEET				2219 129

Location PARAMUS

Estimate Sheet

W.O. 4862.01		Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.		Date 5-21-80	Sheet 1 of 1	
Project GEO-THERMAL H.W. SYSTEM					Est. by C. P. OSTROSKY		Ext. Chk'd. by
Location EAST MESA, CALIF.					Discipline		Approved by
Description General Const. CASE II			ESTIMATED COST				Total Amount
Account No.	Description		MATERIAL	LABOR			
	SHEET # 1 - 24'x25'x15 HI. BLDG.		7224	2201	9425		
	" # 2 - 23'x10'x7 " "		3124	1061	4185		
	TOTAL DIRECT COST.		10348	3262	13610		
	INS. & TAXES ON LABOR	20%		652	652		
	MOBILIZATION " "	10%		326	326		
	Rentals " "	10%		326	326		
	SUPERVISION " "	10%		326	326		
	CONTINGENCY mat & lab	20%	2070	652	2722		
			12418	5544	17962		
	+ 15% OVERHEAD - PROFIT				2694		
	TOTAL AMT ESTIMATE.				20656		
TOTAL THIS SHEET							

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 1 of 2
Project GEO-THERMAL H.W. SYSTEM	Est. by C. P. OSTROSKY		Ext. Chk'd. by	
Location EAST MESA, CALIF.	Discipline GENERAL		Approved by	

Description		CASE II		ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	Shed at Well Pumps										
	12"x12" (212sq'd.)	288	S.F.	3.25	936	-	-	-	-		936
	PRE-ENGINEERED BUILDING										
	24'x25'x15' HIGH	600	S.F.	6.50	3900	-	-	-	-		3900
	CONCRETE FOUNDATION										
3.3-14-011	FLOOR Slab 4"										
	25'x24'x.1'=600±27	22	C.Y.	48	1056	-	-	82	1804		2860
33-26-010	FLOAT FINISH	600	S.F.	-	-	-	-	.20	120		120
8.3/45	ROLL-UP DOOR 8'x8'	1	ea	420	420	-	-	155	155		575
8.1/20	METAL DOOR 13 1/4"x3'x7'	2	ea	145	290			56	112		402
7.6/050	LOUCERS 30'x24"	2	ea	11	22		4.70	10	10		32
	LIGHTING		L.S	1-	600		-	-	-		600
	TOTAL THIS SHEET				7224				2201		9425

BR5901 (2/76)

Estimate Sheet

Page 22 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 2 of 2
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline G.C.	Approved by

Description				ESTIMATED COST							
Account No.	Description	Qty.	Unit	Material		Labor				Total Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	CONCRETE FONDATION										
	& 4" FLOOR Slab	9	CY.	48	432	-	-	82	738	1170	
	FLOAT FINISH	230	SF	-	-			120	46	46	
	ROLL-UP DOOR 8'x8	1	ea	420	420			155	155	575	
	METAL DOOR 13/4"x3'x7'	2	ea	145	290			56	112	402	
	LOUVERS - 30"x24"	2	ea	11	22			470	10	31	
								-	-		
	LIGHTING		LS		350	-		-	-	350	
	PRE-ENGINEERED BLDG.										
	23 x 10 x 7	230	S.F	7 ⁰⁰	1610					1610	
	TOTAL THIS SHEET				3124				1061	4185	

Burns and Roe
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 24 of

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u>5-21-80</u>	Sheet <u>1</u> of <u>11</u>
Project <u>GEO-THERMAL H.W. SYSTEM</u>			Est. by <u>C. P. OSTROSKY</u>	Ext. Chk'd. by
Location <u>EAST MESA, CALIF.</u>			Discipline <u>MECHANICAL</u>	Approved by

Location EAST MESA, CALIF.				ESTIMATED COST						Total Amount	
Description EQUIPMENT CASE II				Material		Labor					
Account No.	Description	Qty.	Unit	Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	GEO-THERMAL PROCESS Pump 30 HP	1	ea	8500	8500	20	20	19	380	8	880
	GEO-THERMAL Well REINJECTION Pump 100 HP	1	ea	32000	32000	20	20		380	32	380
	START-UP.		LS	-	-	10	10		190		190
	THRESHOLD ADDITIVES METERING Pump 1/4 HP	2	ea	860	1720	1.5	1.5		29	1	749
	THRESHOLD ADDITIVE TANK & AGITATOR 1/4 HP	1	ea	4950	4950	30	3.0		57	5	007
	SOFTENED WATER PUMPS	2	ea	7340	14680	1.5	3.0		57	14	737
	HEAT RECOVERY SECTION	1	ea	276000	276000	5.0	5.0		95	276	095
	INCINERATOR PREHEATER	1	ea	41000	41000	4.0	4.0		76	41	076
	TOTAL THIS SHEET				378850				1264	380	114

BR5901 (2)

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 25 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 2 of 11
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline	Approved by

Description EQUIPMENT (CONT.) CASE II				ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	STARCH DRYER PREHEATER		ea	19200	19200	4.0	4.0	19	76	19	276
	STARCH DRYER PREHEATER	1	ea	32000	32000	3.0	3.		57	32	057
	SOFTENED WATER Preheater Pipes	1	ea	52000	52000	2.5	3		57	52	057
	STEAM JACKET EVAPORATOR	1	ea	591200	591,200	—	—		—	591	200
	TURBINE GENERATOR 2 MW	1	ea	360000	360,000	4.0	4		76	360	076
	TOTAL THIS SHEET				1,054,400					266	1,054,666

*Composite Rate - Based on Type of Work

BR5901 (2/76)

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 26 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 5-21-80	Sheet 3 of 11
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline	Approved by

Description EQUIP. SUMMARY				ESTIMATED COST						Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost	
	DESUPER HEATER.	1	ea	4200	4200	1	10	19	190	42190
	56541# / H ₂ O @ 150 PSIG.									
	HEAT RECOVERY SECT.	1	ea	6600	6600	6	6		114	6714
	FEED HEATER.									
	STORAGE TANK 20,000	2	ea	10000	20000		20		380	20380
	STORAGE " 10,000	1	ea	7600	7600		5		95	7695
	INSULATION	50,000	S.F		50000				25000	75000
	CEMENT Rental	7	Days	1600	11200		60		1140	12340
	CONCRETE @ TANKS	246	C.Y.	200	36900					36900
	SYSTEM START-UP.	6	Days	250	1500	8	48		912	2412
	BUILDING Sheds 2 Reqd									
	AT Wells									
	144 sq ft. each	288	S.F	15-	4320.		-		-	4320
	PIPING @ TANKS SEE			1-	12490				9672	22162
	Attached (Sht 26A)									
	TOTAL THIS SHEET				154810				37503	192313

*Composite Rate - Based on Type of Work

BUR-901 (2)

Burns and Roe, COST ESTIMATING & SCHEDULING DEPARTMENT

Location PARAMUS

Estimate Sheet

Page 26/1 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date May 21, 80	Sheet 1 of 1
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline Mech.	Approved by

Description				ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	PIPING @Storage Tanks.										
	4"Sch 40 BLK STEEL.	180	LF	4.49	808	.23	41	19.	779		
	4" weld Elbs.	13	ea	14	182	6.2	81		1539		
	4 " Tees.	3	"	33	99	9.3	28		532		
	4" Gate Valve Pigd.	12	"	489	5868	2.0	24		456		
	4" Check "	3	"	491	1473	2.0	6		114		
	4. Control "	1	"	520	520	2.0	2		38		
	4" Flanges	311	"	18	612	1.9	65		1235		
	4" B/A. Sels.	34	"	7.38	251	1.15	39		741		
	4" INSULATION	220	LF	7.50	1650	1.05	231		4389		
	TEST.	180	LF	.15	27	1.05	9		171		
	PIPE Supports	4	ea	250	1000	5	20		380		
	TOTAL THIS SHEET				12490				9672	22	162

*Composite Rate Based on Type of Work

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 27 of

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client <u>CORN PRODUCTS INC.</u> <u>EAST MESA, CALIF.</u>	Date <u>5-21-80</u>	Sheet <u>4</u> of <u>11</u>
Project <u>GEO-THERMAL H.W. SYSTEM</u>			Est. by <u>C. P. OSTROSKY</u>	Est. Checked by <u> </u>
Location <u>EAST MESA, CALIF.</u>			Discipline <u>MECHANICAL</u>	Approved by <u> </u>

Description				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	PIPE BELOW Grade.							19				
	4" Sch. 80 BLK STEEL P.E	2060	L.F.	6.51	13412	.007	15		285			13,697
	4" Sch. 80 W. Ells.	7	EA.	14.-	98	6.2	43		817			915
	4" GATE VALVE. flg'd.	2	EA.	489	978	2.1	4		76			1054
	4" CHECK "	2	EA.	491	982	2.1	4		76			1058
	4" 150# FLANGES	4	EA	18-	72	1.9	8		152			224
	4" LINE Welds.	52	EA.	3-	156	1.9	110		2090			2246
	TEST-LINE.	2060	L.F.	.15	309	.005	10-		190			499
	DISTRIBUTION.	2060	L.F.	.10	206	.010	21-		399			605
	WRAP PIPE COATING.	2200	L.F.	.56	1232	.20	44		836			2068
	TOTAL THIS SHEET				17445				4921			22366

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT

Location PARAMUS
Estimate Sheet

Page 28 of

W.O. <u>4862.01</u>	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date C. P. OSTROSKY	Sheet 5 of 11
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	
Location EAST MESA, CALIF.			Discipline	
Description		Approved by		

Account No.	Description	Qty.	Unit	ESTIMATED COST						Contract Unit Cost		Total Amount
				Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	INSULATION. 2" FIBER-GLASS WITH WATER-PROOF JACKET.								19			
	4" PIPE.	2100	L.F.	7.50	15700	.05	105		1995			17,695
	4" FITTINGS			-	-							
	EXCAVATION:											
	2100' x 3' deep & 4' wide:											
	25200 cu' ft. ÷ 27	933	C.Y.	2.50	2332		-		-			2332
	Removal	100	C.Y.	2.00	200		-		-			200
	Road Cut & Removal	110	S.F.	1. -	110		-		-			110
	Relch. Road	110	S.F.	1.50	165		-		-			165
	SITE RESTORATION	8400	S.F.	1.10	840		-		-			840
	MISC. BARRIERS, CROSS-OVER Plates, Lights	-	-				-					200
			L.S.	200	200							200
	Total this sheet				19547				1995			21

*Contract to Be Paid Based on Time of Work

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 29 of

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date <u> </u>	Sheet <u>6</u> of <u>11</u>								
Project <u>GEO-THERMAL H.W. SYSTEM</u>			Est. by <u>C. P. OSTROSKY</u>									
Location <u>EAST MESA, CALIF.</u>			Discipline <u> </u>									
Description <u>EXTERIOR WATER ABOVE GRADE</u>		ESTIMATED COST								Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	4" Sch. 80 BLK STEEL PIPE	140	L.F.	4.49	629	.23	32	19	608			1237
	2 1/2" " " " "	460	"	3.42	1573	.30	138		2622			4195
	4" Sch. 80 weld ELB	9	ea	14-	126	6.2	55		1045			1171
	2 1/2" " " " "	10	ea	650	65-	4.0	40		760			825
	4" " " " Tees	2	ea	33	66	9.3	19		361			427
	2 1/2" " " " "	1	ea	16	16	6.9	7		133			149
	4" x 2 1/2" Conc. Reducers	2	ea	10-	20	5.4	11		209			229
	4" LINE WELDS	7	ea	23	21	6.9	48		912			933
	2 1/2" " " "	23	ea	3	69	4.8	110		2090			2159
	4" gate Valve flgd.	2	ea	489	978	2.	4		76			1054
	2 1/2" " " "	2	ea	420	840	1.2	2		38			878
	4" Check " " "	1	ea	491	491	2.1	2		38			529
	2 1/2" " " "	1	ea	345	345	1.2	1		19			364
	4"-150# w.v. flangeo.	5	ea	18	90	1.9	10		190			280
	2 1/2" " " "	5	"	12	60	1.2	7		133			193
Total this Sheet.					5389				9234			14623

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT

Location PARAMUS
Estimate Sheet

Page 30 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date C. P. OSTROSKY	Sheet 7 of 11
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Est. Ck'd. by
Location EAST MESA, CALIF.			Discipline	Approved by
Description PIPE ABOVE GROUND (CONT.)				

PIPE ABOVE GROUND (CONT.)				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	4" BOLT-GASKETS	6	ea	7.38	44	1.15	7	19	133			177
	2 1/2 " " "	6	"	4.1	25	.57	3		57			82
	DISTRIBUTION	600	L.F	.10	60	.010	6		114			174
	TEST	600	L.F	.15	90	.005	3-		57			147
	PIPE STANDS 20' High	10	ea	250	2500	5	50		950			3450
	6" PIPE w/ SONO-TUBE BASE.											
	INSULATION											
	2" FIBER GLASS w/ weather proof JACKET.											
	4"	200	L.F	7.50	1500	1.05	200		3800			5300
	2 1/2	500	"	5.50	2750	.50	250		4750			7500
	TOTAL THIS SHEET				6969				9861			16

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 31 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date	Sheet <u>8</u> of <u>11</u>
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline MECHANICAL	Approved by

Description				ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	3" Sch. 40 BLK STEEL PIPE	180	L.F.	3.26	586	.081	15	19	285		871
	2 1/2" " " " "	260	L.F.	2.00	520	.066	17		323		843
	3" weld Ells	9	ea	6-	54	3.8	34		646		700
	3 " TEE	1	..	15	15	4.2	4		76		91
	3" 150# Gate Valve fig'd	4	ea	489	1956	2.1	8		152	2	108
	3" " Swing C. Valve "	1	..	419	419	1.5	1.5		29		448
	3" 150# W.N. Flanges	10	ea	13.34	133	1.4	14		266		399
	2" Bolt & Gaskets	10	ea	427	428	.87	.9		17		445
	2 1/2" 150# mal. 90's sch'd	7	ea	350	25	.75	5		95		120
	2 1/2" Threebollet	1	"	10	10	2	2		38		48
	2 1/2" B.B. Gate Valve sch'd	3	..	56	168	1.50	5		95		263
	2 1/2" " Check " "	1	..	68	68	1.50	2		38		106
	MISC. NIPPLES-UNIONS		L.S.	100	100	-	-	-	-		100
	TEST	440	L.F.	.15	66	.005	3		57		123
	DISTRIBUTION	440	L.F.	.10	44	.010	4	✓	76		120
	TOTAL THIS SHEET				4592				2193		6785

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
 Location PARAMUS
 Estimate Sheet

Page 32 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date	Sheet <u>32</u> of <u>11</u>
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline	Approved by

Description SOFT WATER SYSTEM Case II				ESTIMATED COST						Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost	
	PIPE SUPPORTS	9	ea	250	2250	5	45	19.	855	3105
	2" FIBER GLOSS INSULATION									
	w/ weatherproof jacket									
	3"	200	L.F.	6.00	1200	.075	15-		285	1485
	2"	280	"	5.50	1540	.060	17-	✓	323	1863
TOTAL THIS SHEET					4990				1463	6453

*Composite Rate - Based on Type of Work

Burns and Roe, COST ESTIMATING & SCHEDULING DEPARTMENT

Location PARAMUS
Estimate Sheet

Page 33 of

W.O. <u>4862.01</u>	Type Estimate <u>BUDGET</u>	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date	Sheet <u>10</u> of <u>11</u>
Project <u>GEO-THERMAL H.W. SYSTEM</u>	Est. by <u>C. P. OSTROSKY</u>		Ext. Chk'd. by	
Location <u>EAST MESA, CALIF.</u>	Discipline <u>Mechanical</u>		Approved by	

Project				Location				Description				ESTIMATED COST				Total Amount	
GEO-THERMAL H.W. SYSTEM				EAST MESA, CALIF.				STEAM PIPE SYSTEM CASE II									
Account No.	Description	Qty.	Unit	Material		Labor				Total Amount							
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost								
	3" Sch 40 BLK STEEL PIPE W/F	60	L.F.	11-	660	.172	10	19	190	850							
	4"	25	"	4.65	116	.10	3		57	173							
	2 1/2"	10	"	3.65	37	.075	.1		19	56							
	1"	60	"							-							
										-							
	8" weld Ells.	5	ea.	40	200	7.2	35		605	865							
	4" " "	3	"	9	27	4.	12		228	255							
	2 1/2" " "	1	"	4	4	2	2		38	42							
	2 1/2" NOZZLE	1	"	12.50	13	2.8	3		57	70							
	8" 150" C.S. Gate Valve	1	ea.	1240	1240	3.0	3		57	1297							
	8" " W.N. Flanges	2	"	44	88	3.6	7		133	221							
	8" " Bolt & Gasket Set	2	"	18	36	2.	4		76	112							
	TEST	155	L.F.	.15	24	.005	7		133	157							
	DISTRIBUTION	155	"	.10	16	.010	2-		38	54							
	1" FITTINGS		L.S.	100	100					100							
	TOTAL THIS SHEET				2471				1691	4162							

*Composite Rate - Based on Type of Work

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page 34 of

W.O. 4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date	Sheet 11 of 11
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	Ext. Chk'd. by
Location EAST MESA, CALIF.			Discipline mechanical	Approved by

Description				ESTIMATED COST						Total Amount	
Account No.	Description	Qty.	Unit	Material		Labor					
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost		
	2" INSULATION w/ Weather Proof Jacket							19			
	8"	80	L.F	9 ⁰⁰	720	.150	12		228		948
	4"	30	"	7 ⁵⁰	225	.105	3		57		282
	2 1/2"	15	"	6-	90	.50	1-		19		109
	1"	70	"	4-	280	.25	2-		38		318
	Pipe Supports -	-	L.S	450	450	5.0	5-		95		545

Burns and Roe,
COST ESTIMATING & SCHEDULING DEPARTMENT

Page 12 of

Location PARAMUS

Estimate Sheet

4862.01	Type Estimate BUDGET	Client CORN PRODUCTS INC. EAST MESA, CALIF.	Date 16/may/80	Sheet 1 of 7
Project GEO-THERMAL H.W. SYSTEM			Est. by C. P. OSTROSKY	
Location EAST MESA, CALIF.			Discipline 	
				Approved by

ELECTRICAL Summary CASE II				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
#1 2	480 VOLT-400AMP SERVICE				8400		288	23	6624			15024
#344	125 HP GEOTHERMAL PUMP				28000		640		14720			42720
#5	100HP REINJECTION PUMP				7000		304		6992			13992
#6	2/7.5HP-SOFT H2O RET PUMPS				1500		80		1840			3340
#7	INSTRUMENTATION				400		160		3680			4080
	TOTAL COST				45300				33856			79156
	INS. & TAXES ON LABOR	20%							6771			6771
	MOBILIZATION .. "	10%							3386			3386
	RENTALS .. "	10%							3386			3386
	SUPERVISION .. "	10%							3386			3386
	CONTINGENCY LAB & Mat.	10%			4530				3386			7916
	TOTAL				49830				5471			104001
	OVERHEAD & PROFIT	15%										15600
	TOTAL AMT ESTIMATE											119601
	Electrical From Turbine Generator											150,000
	To Sub-Station											
	TOTAL											269,600

119600

Burns & Roe, Inc.
COST ESTIMATING & SCHEDULING DEPARTMENT

Page 36 of

Location
Estimate Sheet

Account No. <u>4862-01</u> Description <u>Geothermal H.W. System</u> Location <u>East Mesa, CA</u>		Type Estimate <u> </u> Client <u>CORN PRODUCTS</u>		Date <u>10/21/70</u> Est. by <u>JVK</u> Discipline <u>Electrical</u>				Sheet <u>2</u> of <u>7</u> Ext. Chk'd. by <u> </u> Approved by <u> </u>		
Account No.	Description	Qty.	Unit	ESTIMATED COST				Contract Unit Cost		Total Amount
				Material Cost/Unit	Material Cost	Labor MH/Unit	Labor MH's	Rate*	Cost	
	400' 3" CPT HTR (EXIST. SPACE)	1	EA	4300/EA	4300	48/EA	48			
	4' 500MM CONNECTIONS	LOT	-	-	20	-	16			
	3 1/2" R.G. STEEL CPT	60'	FT	52 1/2/FT	313	.25/FT	15			
	3 1/2" ELBOWS GROUP	3	EA	21 30/EA	64	4/EA	12			
	PULL BOX	1	EA	125/EA	125	16/EA	16			
	CPT HOLE DRILLING	ALLOW	LOT		29		4			
	3 1/2" PVC	150'	FT	2 10/FT	315	.10/FT	15			
	3 1/2" PVC ELBOWS	2	EA	900/EA	18	2/EA	4			
	TRENCH DRAINAGE	150'	LINE FT	2 00/LINE FT	300	INC	-			
	3500' 4" 1 1/2" GND. WIRE	750'	FT	4 50/FT	2052	.04/FT	30			
	3500' 4" 1 1/2" GND. WIRE	ALLOW	LOT		100		12			
	GROUNDING C.	ALLOW	LOT		350		22			
	THROUGH	1	EA	60/EA	60	16/EA	16			
	500 TO 350 SPALICONS	4	EA	5 00/EA	20	3/EA	12			
	500 FT 3/4"	4	EA	4 50/EA	18	2.5/EA	10			
	500 TO 1/2"	4	EA	4 50/EA	16	2/EA	8			
	EXIST. SPACE	ALLOW	LOT		50	LOT	16			
	EXIST. SPACE	ALLOW	LOT		250	LOT	32			
	ADD TO SEEING HOLE DRILLING MATERIAL	ALLOW	LOT							
TOTAL					118,420		288			

COST ESTIMATING & SCHEDULING DEPARTMENT

Page 37 of 7

Location
Estimate Sheet

Estimate Sheet												
4862-01		Type Estimate		Client				Date 10/10/80		Sheet 3 of 7		
Geothermal H.W. System				CORN PRODUCTS				Est. by JVK		Ext. Chkd. by		
East Mesa, CA								Discipline Electrical		Approved by		
125 HP GEOTHERMAL PUMP				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	SIZE 5' DIA. B. STRAP-ON	1	EA	3001/EA	3000	32/EA	32					
	4.500MM LINE CONDUIT		LOT		20	4 EA	8					
	4.500MM COND. CONDUIT		LOT		20	4 EA	8					
	PULL BOX	1	EA	150/EA	150	8 EA	8					
	TRANSFORMER	1	EA	50/EA	50	4 EA	4					
	400V-3P-600V DISC SW	1	EA	285/EA	285	8 EA	8					
	REAR END P.D. STATION	1	EA	75/EA	75	4 EA	4					
	400V TO 110V 1P TRANSFORMER	1	EA	450/EA	450	16 EA	16					
	TABLET 1P SWITCHER	1	EA	95/EA	95	2 EA	2					
	30 AMP DISC SW	2	EA	60/EA	120	2 EA	2					
	LIGHTING POLE 110V	ALICE	LOT	-	300	4 EA	8					
	1/4" 110V W. HOSEA HOSE UP	2	LOT	20 EA	40	4 EA	8					
	1/2" 110V " " "	1	LOT	50 EA	50	32 EA	32					
	3/4" 110V CONDUIT	100'	LOT	LOT	69	10 EA	8					
	3" " " "	20'	EA	4 EA	85	10 EA	4					
	3" " " " ELB.	3	EA	17.00/EA	51	4 EA	12					
	3" " " "	1000'	FT	10 EA	1000	10 EA	80					
	3" " " " "	2	EA	8 EA	16	2 EA	4					
	MISC. & SEISMIC HARDWARE				124		16					
	TOTAL - SHEET 3				6000		336					

UR-001 (2)

32

Estimate Sheet

12. If GSO (GSO) pump continues

Composite Rate -- Based on Type of Work

Estimate Sheet

100 HP AC Injection Pump

*Composite Rate - Based on Type of Work

40

4862-01	Type Estimate	Client CORN PRODUCTS	Date	Sheet 6 of 9
Geothermal H.W. System			Est. by JVK	Ext. Chk'd. by
on East Mesa, CA			Discipline Electrical	Approved by

2-7 1/2" IP				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	HOOD UP - GROUND START UP	2	EA	524/EA	1056	6 EA	12					
	LEIS GROUND ID. STATION	2	EA	75/EA	150	2 CH	4					
	3/4" RIGID CONDUIT	100'	LOT		69	105	12					
	SD. TAPPING MATERIAL	ALLOW			7		6					
	FLY TIE IN	500	FT	0.053/FT	29	.007	4					
	FLY TIE IN	500		0.084	42	.008	4					
	FLY TIE IN	ALLOW			17		2					
	HOOD UP - GROUND START UP & TEST				130		36					
	TOTAL				1500		80					

4

4862-01	Type Estimate	Client	Date 16/04/80	Sheet 7 of 7
Geothermal H.W. System		CORN PRODUCTS	Est. by JVK	Ext. Ch'd. by
on East Mesa, CA			Discipline Electrical	Approved by

INSTRUCTIONS				ESTIMATED COST						Contract Unit Cost		Total Amount
Account No.	Description	Qty.	Unit	Material		Labor				Unit Price	Amount	
				Cost/Unit	Cost	MH/Unit	MH's	Rate*	Cost			
	1200 1/2" CONCRETE PILE		FBS		—		16					
	#14 #12 CONCRETE				11		5					
	CONCRETE BENTS ALLOW	10			20		10					
	PILE	10			20		20					
	PILE CONCRETE	30			60		40					
	3/4" R. G. S. CDT	200	1/2"		140	.08	16					
	PILE CONCRETE	1160	LOT		70		10					
	#14	1000			60		9					
	#12	100			9		9					
	CONCRETE STR. OF DIMENSIONS				10		24					
	TOTAL				400		160					

Burns and Roe
COST ESTIMATING & SCHEDULING DEPARTMENT
Location PARAMUS
Estimate Sheet

Page _____ of _____

W.O. 4862-01	Type Estimate	BUDGET	Client	Date	Sheet of
Project	GEO-THERMAL H.W. SYSTEM		CORN PRODUCTS, INC. EAST MESA, CALIF.	Est. by	Ext. Chk'd. by
Location	EAST MESA, CALIF.			Discipline	Approved by
Description					

[illegible]

*Composite Rate — Based on Type of Work

BR5901 (2/76)

W.O. 4862-01

GROTHERRM H.W. SYSTEM
EAST MESH - CA

CLIENT: CORN PRODUCTS

MAY 16, 1980

J.V.K.
ELECTRICAL

ALLOW 60' RIGID D.T.
100' T & B - PVC

4" 500 MCM
(3 1/2" CDT)

THROUGH IN STARCH DRYER AREA

SIZE
1
COMP.
STARTER

SIZE
1
COMP.
STARTER

SIZE
1
COMP.
STARTER

400V
FUSED
DISC
SW

4" 500 MCM
3 1/2" CDT

500'
T & B - BROTHERN
100'

3 1/4" CDT
4" 12
3" 1/4
7 1/2"

7 1/2"

4" 500 MCM
100' - 3" 1/4
T & B - BROTHERN

SIZE
5
COMP.
STARTER

125
HP

480V

110V-1P

THROUGH

STARTER

DISC.
SW.

110V
LIGHTS &
RECEPT
IN PUMP HOUSE

1 1/2" 110V-1P

Page _____ of _____

W.O. 4862-01	Type Estimate	BUDGET	Client CORN PRODUCTS, INC. EAST MESA, CALIF.	Date	Sheet of
Project	GEO-THERMAL H.W. SYSTEM			Est. by	Ext. Chk'd. by
Location	EAST MESA, CALIF.			Discipline	Approved by

[illegible]

APPENDIX D

ENERGY REQUIREMENTS FOR INDIVIDUAL CORN MILLING PROCESSES

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 1
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

1. Corn Steep Heating

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 2
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

2- Sleep Water Evaporator

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 3
 Drawing No. _____ Calc. No. _____ Sheet _____ of _____
 By AK Checked _____ Approved _____
 Title Corn Product

3. Germ Drying

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 4
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Products

4. Gluten Drying

**Burns and Roe
Industrial Services Corp.**

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 5
 Drawing No. _____ Calc. No. _____ Sheet _____ of _____
 By AK Checked _____ Approved _____
 Title Corn Product

5. Fiber Drying

W.O. No. 4862-01 Date 12/11/79 Book No. _____ Page No. 6
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

6. Starch Drying

**Burns and Roe
Industrial Services Corp.**

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 7
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Com Product

7. Starch Preheating - Liquefaction

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 8
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

8. 15F Carbon Treating / #1 Sweet Water Heater

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 9
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

9. Dextrose Preheater

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 10
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

10. Fructose Finisher / vac. System

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 11
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

11. Isomerization Heater/Deaerator Vac. System

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 12
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title COAM Product

12. 2nd Carbon Treating / #2 Sweetwater Heater

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 13
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AZ Checked _____ Approved _____
Title Corn Product

13. HFCS Heater

Burns and Roe
Industrial Services Corp.

W.O. No. 4862-01 Date 12/12/79 Book No. _____ Page No. 14
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Com Product

14. Caustic Storage Tank

Burns and Roe
Industrial Services Corp.

W.O. No. 4562-01 Date 12/12/79 Book No. _____ Page No. 15
Drawing No. _____ Calc. No. _____ Sheet _____ of _____
By AK Checked _____ Approved _____
Title Corn Product

15. SO₂ Storage Tank

APPENDIX E

Cash Flow Analysis

This Appendix contains the computer output data for the cash flow analysis.

W.O. No. 1862-01 Date _____
 Drawing No. _____
 By _____ Checked _____
 Title Gas Products - Geothermal Study Calc. No. _____
 Book No. _____
 Approved _____
 Page No. _____
 Sheet _____ of _____

Cash Flow Analysis

CASE: I BASE CAPITAL COST

Initial Nat. Gas Escalation: 20 %

Nat. Gas Savings = 44.06 MMbtu/yr

Elect. Consumption = -4218 KWH/yr

Well Cost = \$1,570,000 surface system = \$331,980 Total = \$1,901,980 Buildings = \$5,465

ALL ANNUAL COSTS ARE IN \$1000

No of Years After Startup	Unit Nat. Gas Cost, \$/MMBtu	Unit Elect. Cost, \$/KWH	Capital Cost	Taxes & Insur- ance @ 2%	Elect. Power Cost	Mainten- ance Cost @ 3%	Chem- ical Cost	Nat Gas Sav- ings	Net Cash Income	Intang- ible Drilling Cost	Depre- ciation	Tax- able Income	Tax Credit	Income Tax @ 48.6 %	Net Cash Flow	Cumu- lative Cash Flow
Present	3.80	.0376	-1902													
0	4.56	.0432	-1997						-1997							
1	5.472	.0497		-39.9	209.7	-59.9	-5.26	241.1	345.7	-1154	-99.8	-908.1	325.3	766.6	1112.3	
2	6.566	.0572		-43.9	241.3	-65.9	-5.79	289.3	415.0		-99.8	315.2		-153.2	261.8	1374.1
3	7.880	.0658		-48.3	277.4	-72.5	-6.36	347.2	497.4		-99.8	397.6		-193.2	304.2	1678.3
4	9.456	.0756		-53.2	319.0	-79.7	-7.00	416.6	595.7		-99.8	495.9		-241.0	354.7	2033.0
5	10.401	.0832		-58.5	350.9	-87.7	-7.70	458.3	655.3		-99.8	555.5		-270.0	385.3	
6									720.8						419.0	
7									792.9						456.0	
8									872.2						496.8	
9									959.4						541.6	
10									1055.4						591.0	
11									1160.9						645.2	
12									1277.0						704.9	
13									1404.7						770.5	
14									1545.2						842.7	
15									1699.7						922.1	
16									1869.6						1009.5	
17									2056.6						1105.6	
18									2262.3						1211.3	
19									2488.5						1327.6	
20									2737.4		Y				1455.5	

GENERAL DATA APPLICABLE TO ALL CASES

GAS ESC = 0 %

FIRST YEAR NAT.GAS COST, \$/MMBTU	3.800
FIRST YEAR ELECTRICITY COST, \$/KWH	0.037
TAX & INSURANCE, % OF CAPITAL COST	2.0
MAINTENANCE, % OF CAPITAL COST	3.0
INCOME TAX, % OF TAXABLE INCOME	48.6
NUMBER OF PLANT LIFE CASES	1
PLANT LIFE, YEARS	20

NUMBER OF NAT. GAS CASES = 1

NAT. GAS ESCALATION BY YEAR, IN PERCENT

YEAR CASE 1

2 0

ESCALATION RATE IS CONSTANT THEREAFTER

ELECTRICITY ESCALATION BY YEAR, IN PERCENT

YEAR RATE

2 0

ESCALATION RATE IS CONSTANT THEREAFTER

ANNUAL ESCALATION RATES, IN PERCENT, FOR...

TAXES AND INSURANCE = 0

MAINTENANCE = 0

CHEMICAL COST = 0

CASE I -25% CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
ELECTRIC CONSUMPTION, KWH/YR -4218
CHEMICAL COST (YR 1), \$ 5.259
CAPITAL COST, \$ 1497.8
INTANGIBLE DRILLING COST, \$ 865.5
TAX CREDIT, \$ 244

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-29.9	ELECTRICITY	158.5
MAINTENANCE	-44.9	CHEMICALS	-5.2
GAS SAVINGS	167.4	NET CASH INCOME	245.8
INTANG DRILL COST	-865.5	DEPRECIATION	-74.8
TAXABLE INCOME	-694.5	TAX CREDIT	244.0
INCOME TAX	581.5	NET CASH FLOW	827.4

YEAR	NET CASH INCOME	NET CASH FLOW
1	245.8	827.4
2	245.8	162.7
3	245.8	162.7
4	245.8	162.7
5	245.8	162.7
6	245.8	162.7
7	245.8	162.7
8	245.8	162.7
9	245.8	162.7
10	245.8	162.7
11	245.8	162.7
12	245.8	162.7
13	245.8	162.7
14	245.8	162.7
15	245.8	162.7
16	245.8	162.7
17	245.8	162.7
18	245.8	162.7
19	245.8	162.7
20	245.8	162.7

ON NET CASH INCOME

ROI= 15.49 %

PAYBACK= 6.0 YEARS

ON NET CASH FLOW

ROI= 16.73 %

PAYBACK= 5.1 YEARS

CASE I BASE CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
 ELECTRIC CONSUMPTION, KWH/YR -4218
 CHEMICAL COST (YR 1), \$ 5.259
 CAPITAL COST, \$ 1997.1
 INTANGIBLE DRILLING COST, \$ 1154
 TAX CREDIT, \$ 325.3

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-39.9	ELECTRICITY	158.5
MAINTENANCE	-59.9	CHEMICALS	-5.2
GAS SAVINGS	167.4	NET CASH INCOME	220.9
INTANG DRILL COST	-1154.0	DEPRECIATION	-99.8
TAXABLE INCOME	-1032.9	TAX CREDIT	325.3
INCOME TAX	827.3	NET CASH FLOW	1048.2

YEAR	NET CASH INCOME	NET CASH FLOW
1	220.9	1048.2
2	220.9	162.0
3	220.9	162.0
4	220.9	162.0
5	220.9	162.0
6	220.9	162.0
7	220.9	162.0
8	220.9	162.0
9	220.9	162.0
10	220.9	162.0
11	220.9	162.0
12	220.9	162.0
13	220.9	162.0
14	220.9	162.0
15	220.9	162.0
16	220.9	162.0
17	220.9	162.0
18	220.9	162.0
19	220.9	162.0
20	220.9	162.0

ON NET CASH INCOME

ROI= 9.13 %

PAYBACK= 9.0 YEARS

ON NET CASH FLOW

ROI= 12.05 %

PAYBACK= 6.8 YEARS

CASE I +25% CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
 ELECTRIC CONSUMPTION, KWH/YR -4218
 CHEMICAL COST (YR 1), \$ 5.259
 CAPITAL COST, \$ 2496.3
 INTANGIBLE DRILLING COST, \$ 1442.4
 TAX CREDIT, \$ 406.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-49.9	ELECTRICITY	158.5
MAINTENANCE	-74.8	CHEMICALS	-5.2
GAS SAVINGS	167.4	NET CASH INCOME	195.9
INTANG DRILL COST	-1442.4	DEPRECIATION	-124.3
TAXABLE INCOME	-1371.2	TAX CREDIT	406.6
INCOME TAX	1073.0	NET CASH FLOW	1268.9

YEAR	NET CASH INCOME	NET CASH FLOW
1	195.9	1268.9
2	195.9	161.3
3	195.9	161.3
4	195.9	161.3
5	195.9	161.3
6	195.9	161.3
7	195.9	161.3
8	195.9	161.3
9	195.9	161.3
10	195.9	161.3
11	195.9	161.3
12	195.9	161.3
13	195.9	161.3
14	195.9	161.3
15	195.9	161.3
16	195.9	161.3
17	195.9	161.3
18	195.9	161.3
19	195.9	161.3
20	195.9	161.3

ON NET CASH INCOME

ROI= 4.74 %

PAYBACK= 12.7 YEARS

ON NET CASH FLOW

ROI= 8.93 %

PAYBACK= 8.6 YEARS

CASE II -25% CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
 ELECTRIC CONSUMPTION, KWH/YR -19868
 CHEMICAL COST (YR 1), \$ 5.712
 CAPITAL COST, \$ 2064.5
 INTANGIBLE DRILLING COST, \$ 865.5
 TAX CREDIT, \$ 383.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-41.2	ELECTRICITY	747.0
MAINTENANCE	-61.9	CHEMICALS	-5.7
GAS SAVINGS	233.4	NET CASH INCOME	871.5
INTANG DRILL COST	-865.5	DEPRECIATION	-103.2
TAXABLE INCOME	-97.1	TAX CREDIT	383.8
INCOME TAX	431.0	NET CASH FLOW	1302.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	871.5	1302.5
2	871.5	498.1
3	871.5	498.1
4	871.5	498.1
5	871.5	498.1
6	871.5	498.1
7	871.5	498.1
8	871.5	498.1
9	871.5	498.1
10	871.5	498.1
11	871.5	498.1
12	871.5	498.1
13	871.5	498.1
14	871.5	498.1
15	871.5	498.1
16	871.5	498.1
17	871.5	498.1
18	871.5	498.1
19	871.5	498.1
20	871.5	498.1

ON NET CASH INCOME

ROI= 42.18 %

PAYBACK= 2.3 YEARS

ON NET CASH FLOW

ROI= 33.93 %

PAYBACK= 2.5 YEARS

CASE II BASE CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 2752.7
INTANGIBLE DRILLING COST, \$ 1154
TAX CREDIT, \$ 511.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-55.0	ELECTRICITY	747.0
MAINTENANCE	-82.5	CHEMICALS	-5.7
GAS SAVINGS	233.4	NET CASH INCOME	837.1
INTANG DRILL COST	-1154.0	DEPRECIATION	-137.6
TAXABLE INCOME	-454.4	TAX CREDIT	511.8
INCOME TAX	732.6	NET CASH FLOW	1569.8

YEAR	NET CASH INCOME	NET CASH FLOW
1	837.1	1569.8
2	837.1	497.1
3	837.1	497.1
4	837.1	497.1
5	837.1	497.1
6	837.1	497.1
7	837.1	497.1
8	837.1	497.1
9	837.1	497.1
10	837.1	497.1
11	837.1	497.1
12	837.1	497.1
13	837.1	497.1
14	837.1	497.1
15	837.1	497.1
16	837.1	497.1
17	837.1	497.1
18	837.1	497.1
19	837.1	497.1
20	837.1	497.1

ON NET CASH INCOME

ROI= 30.25 %

PAYBACK= 3.2 YEARS

ON NET CASH FLOW

ROI= 25.89 %

PAYBACK= 3.3 YEARS

CASE II +25% CAP COST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 3440.9
INTANGIBLE DRILLING COST, \$ 1442.4
TAX CREDIT, \$ 639.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-68.8	ELECTRICITY	747.0
MAINTENANCE	-103.2	CHEMICALS	-5.7
GAS SAVINGS	233.4	NET CASH INCOME	802.7
INTANG DRILL COST	-1442.4	DEPRECIATION	-172.0
TAXABLE INCOME	-811.6	TAX CREDIT	639.8
INCOME TAX	1034.2	NET CASH FLOW	1837.0

YEAR	NET CASH INCOME	NET CASH FLOW
1	802.7	1837.0
2	802.7	496.2
3	802.7	496.2
4	802.7	496.2
5	802.7	496.2
6	802.7	496.2
7	802.7	496.2
8	802.7	496.2
9	802.7	496.2
10	802.7	496.2
11	802.7	496.2
12	802.7	496.2
13	802.7	496.2
14	802.7	496.2
15	802.7	496.2
16	802.7	496.2
17	802.7	496.2
18	802.7	496.2
19	802.7	496.2
20	802.7	496.2

ON NET CASH INCOME
ROI= 22.95 %
PAYBACK= 4.2 YEARS

ON NET CASH FLOW
ROI= 20.80 %
PAYBACK= 4.2 YEARS

CASE III -25% CAP CST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
ELECTRIC CONSUMPTION, KWH/YR -18300
CHEMICAL COST (YR 1), \$ 0
CAPITAL COST, \$ 567
INTANGIBLE DRILLING COST, \$ 0
TAX CREDIT, \$ 139.95

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-11.3	ELECTRICITY	688.0
MAINTENANCE	-17.0	CHEMICALS	0.0
GAS SAVINGS	-303.6	NET CASH INCOME	356.1
INTANG DRILL COST	0.0	DEPRECIATION	-28.3
TAXABLE INCOME	327.7	TAX CREDIT	139.9
INCOME TAX	-19.3	NET CASH FLOW	336.7

YEAR	NET CASH INCOME	NET CASH FLOW
1	356.1	336.7
2	356.1	196.8
3	356.1	196.8
4	356.1	196.8
5	356.1	196.8
6	356.1	196.8
7	356.1	196.8
8	356.1	196.8
9	356.1	196.8
10	356.1	196.8
11	356.1	196.8
12	356.1	196.8
13	356.1	196.8
14	356.1	196.8
15	356.1	196.8
16	356.1	196.8
17	356.1	196.8
18	356.1	196.8
19	356.1	196.8
20	356.1	196.8

ON NET CASH INCOME
ROI= 62.80 %
PAYBACK= 1.5 YEARS

ON NET CASH FLOW
ROI= 41.97 %
PAYBACK= 2.1 YEARS

CASE III BASE CAP CST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
ELECTRIC CONSUMPTION, KWH/YR -18300
CHEMICAL COST (YR 1), \$ 0
CAPITAL COST, \$ 756
INTANGIBLE DRILLING COST, \$ 0
TAX CREDIT, \$ 186.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-15.1	ELECTRICITY	688.0
MAINTENANCE	-22.6	CHEMICALS	0.0
GAS SAVINGS	-303.6	NET CASH INCOME	346.6
INTANG DRILL COST	0.0	DEPRECIATION	-37.8
TAXABLE INCOME	308.8	TAX CREDIT	186.6
INCOME TAX	36.4	NET CASH FLOW	383.1

YEAR	NET CASH INCOME	NET CASH FLOW
1	346.6	383.1
2	346.6	196.5
3	346.6	196.5
4	346.6	196.5
5	346.6	196.5
6	346.6	196.5
7	346.6	196.5
8	346.6	196.5
9	346.6	196.5
10	346.6	196.5
11	346.6	196.5
12	346.6	196.5
13	346.6	196.5
14	346.6	196.5
15	346.6	196.5
16	346.6	196.5
17	346.6	196.5
18	346.6	196.5
19	346.6	196.5
20	346.6	196.5

ON NET CASH INCOME
ROI= 45.83 %
PAYBACK= 2.1 YEARS

ON NET CASH FLOW
ROI= 31.86 %
PAYBACK= 2.8 YEARS

CASE III +25% CAP CST

RUN NO. 1

GAS ESC = 0 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
ELECTRIC CONSUMPTION, KWH/YR -18300
CHEMICAL COST (YR 1), \$ 0
CAPITAL COST, \$ 945
INTANGIBLE DRILLING COST, \$ 0
TAX CREDIT, \$ 233.25

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	3.800	ELECTRICITY, \$/KWH	0.037
TAXES & INSURANCE	-18.9	ELECTRICITY	688.0
MAINTENANCE	-28.3	CHEMICALS	0.0
GAS SAVINGS	-303.6	NET CASH INCOME	337.2
INTANG DRILL COST	0.0	DEPRECIATION	-47.2
TAXABLE INCOME	289.9	TAX CREDIT	233.2
INCOME TAX	92.3	NET CASH FLOW	429.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	337.2	429.5
2	337.2	196.2
3	337.2	196.2
4	337.2	196.2
5	337.2	196.2
6	337.2	196.2
7	337.2	196.2
8	337.2	196.2
9	337.2	196.2
10	337.2	196.2
11	337.2	196.2
12	337.2	196.2
13	337.2	196.2
14	337.2	196.2
15	337.2	196.2
16	337.2	196.2
17	337.2	196.2
18	337.2	196.2
19	337.2	196.2
20	337.2	196.2

ON NET CASH INCOME
ROI= 35.60 %
PAYBACK= 2.8 YEARS

ON NET CASH FLOW
ROI= 25.58 %
PAYBACK= 3.6 YEARS

GENERAL DATA APPLICABLE TO ALL CASES

GAS ESC = 20 %

FIRST YEAR NAT.GAS COST, \$/MMBTU	5.472
FIRST YEAR ELECTRICITY COST, \$/KWH	0.049
TAX & INSURANCE, % OF CAPITAL COST	2.0
MAINTENANCE, % OF CAPITAL COST	3.0
INCOME TAX, % OF TAXABLE INCOME	48.6
NUMBER OF PLANT LIFE CASES	1
PLANT LIFE, YEARS	20

NUMBER OF NAT. GAS CASES = 1

NAT. GAS ESCALATION BY YEAR, IN PERCENT

YEAR	CASE 1
2	20
3	20
4	20
5	10

ESCALATION RATE IS CONSTANT THEREAFTER

ELECTRICITY ESCALATION BY YEAR, IN PERCENT

YEAR	RATE
2	15
3	15
4	15
5	10

ESCALATION RATE IS CONSTANT THEREAFTER

ANNUAL ESCALATION RATES, IN PERCENT, FOR...

TAXES AND INSURANCE =	10
MAINTENANCE =	10
CHEMICAL COST =	10

CASE I -25% CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
 ELECTRIC CONSUMPTION, KWH/YR -4218
 CHEMICAL COST (YR 1), \$ 5.259
 CAPITAL COST, \$ 1497.8
 INTANGIBLE DRILLING COST, \$ 865.5
 TAX CREDIT, \$ 244

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-29.9	ELECTRICITY	209.7
MAINTENANCE	-44.9	CHEMICALS	-5.2
GAS SAVINGS	241.0	NET CASH INCOME	370.7
INTANG DRILL COST	-865.5	DEPRECIATION	-74.8
TAXABLE INCOME	-569.6	TAX CREDIT	244.0
INCOME TAX	520.8	NET CASH FLOW	891.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	370.7	891.5
2	442.3	263.7
3	527.6	307.5
4	628.9	359.6
5	691.8	392.0
6	761.0	427.5
7	837.1	466.6
8	920.8	509.7
9	1012.9	557.0
10	1114.2	609.1
11	1225.6	666.3
12	1348.2	729.3
13	1483.0	798.6
14	1631.3	874.9
15	1794.4	958.7
16	1973.9	1050.9
17	2171.3	1152.4
18	2388.4	1264.0
19	2627.3	1386.8
20	2890.0	1521.8

ON NET CASH INCOME

ROI= 38.74 %

PAYBACK= 3.2 YEARS

ON NET CASH FLOW

ROI= 34.61 %

PAYBACK= 3.0 YEARS

CASE I BASE CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
 ELECTRIC CONSUMPTION, KWH/YR -4218
 CHEMICAL COST (YR 1), \$ 5.259
 CAPITAL COST, \$ 1997.1
 INTANGIBLE DRILLING COST, \$ 1154
 TAX CREDIT, \$ 325.3

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-39.9	ELECTRICITY	209.7
MAINTENANCE	-59.9	CHEMICALS	-5.2
GAS SAVINGS	241.0	NET CASH INCOME	345.7
INTANG DRILL COST	-1154.0	DEPRECIATION	-99.8
TAXABLE INCOME	-908.1	TAX CREDIT	325.3
INCOME TAX	766.6	NET CASH FLOW	1112.3

YEAR	NET CASH INCOME	NET CASH FLOW
1	345.7	1112.3
2	414.9	261.7
3	497.3	304.1
4	595.7	354.7
5	655.3	385.3
6	720.8	419.0
7	792.9	456.0
8	872.2	496.8
9	959.4	541.6
10	1055.3	590.9
11	1160.9	645.2
12	1276.9	704.9
13	1404.6	770.5
14	1545.1	842.7
15	1699.6	922.1
16	1869.6	1009.5
17	2056.6	1105.6
18	2262.2	1211.3
19	2488.5	1327.6
20	2737.3	1455.5

ON NET CASH INCOME

ROI= 30.18 %

PAYBACK= 4.2 YEARS

ON NET CASH FLOW

ROI= 28.11 %

PAYBACK= 3.8 YEARS

CASE I +25% CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
ELECTRIC CONSUMPTION, KWH/YR -4218
CHEMICAL COST (YR 1), \$ 5.259
CAPITAL COST, \$ 2496.3
INTANGIBLE DRILLING COST, \$ 1442.4
TAX CREDIT, \$ 406.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-49.9	ELECTRICITY	209.7
MAINTENANCE	-74.8	CHEMICALS	-5.2
GAS SAVINGS	241.0	NET CASH INCOME	320.7
INTANG DRILL COST	-1442.4	DEPRECIATION	-124.8
TAXABLE INCOME	-1246.4	TAX CREDIT	406.6
INCOME TAX	1012.3	NET CASH FLOW	1333.1

YEAR	NET CASH INCOME	NET CASH FLOW
1	320.7	1333.1
2	387.4	259.8
3	467.1	300.7
4	562.5	349.7
5	618.7	378.7
6	680.6	410.5
7	748.6	445.4
8	823.5	483.9
9	905.9	526.3
10	996.5	572.8
11	1096.1	624.0
12	1205.7	680.4
13	1326.3	742.4
14	1458.9	810.5
15	1604.8	885.5
16	1765.3	968.0
17	1941.9	1058.8
18	2136.1	1158.6
19	2349.7	1268.4
20	2584.7	1389.1

ON NET CASH INCOME

ROI= 24.63 %

PAYBACK= 5.2 YEARS

ON NET CASH FLOW

ROI= 23.75 %

PAYBACK= 4.6 YEARS

CASE II -25% CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 2064.5
INTANGIBLE DRILLING COST, \$ 865.5
TAX CREDIT, \$ 383.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-41.2	ELECTRICITY	988.0
MAINTENANCE	-61.9	CHEMICALS	-5.7
GAS SAVINGS	336.1	NET CASH INCOME	1215.2
INTANG DRILL COST	-865.5	DEPRECIATION	-103.2
TAXABLE INCOME	246.5	TAX CREDIT	383.8
INCOME TAX	263.9	NET CASH FLOW	1479.2

YEAR	NET CASH INCOME	NET CASH FLOW
1	1215.2	1479.2
2	1419.8	779.9
3	1658.9	902.8
4	1938.6	1046.6
5	2132.5	1146.2
6	2345.7	1255.8
7	2580.3	1376.4
8	2838.3	1509.0
9	3122.1	1654.9
10	3434.4	1815.4
11	3777.8	1991.9
12	4155.6	2186.1
13	4571.2	2399.7
14	5028.3	2634.7
15	5531.1	2893.1
16	6084.2	3177.4
17	6692.6	3490.2
18	7361.9	3834.2
19	8098.1	4212.6
20	8907.9	4628.8

ON NET CASH INCOME

ROI= 73.78 %

PAYBACK= 1.5 YEARS

ON NET CASH FLOW

ROI= 56.91 %

PAYBACK= 1.7 YEARS

CASE II BASE CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 2752.7
INTANGIBLE DRILLING COST, \$ 1154
TAX CREDIT, \$ 511.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-55.0	ELECTRICITY	988.0
MAINTENANCE	-82.5	CHEMICALS	-5.7
GAS SAVINGS	336.1	NET CASH INCOME	1180.8
INTANG DRILL COST	-1154.0	DEPRECIATION	-137.6
TAXABLE INCOME	-110.7	TAX CREDIT	511.8
INCOME TAX	565.6	NET CASH FLOW	1746.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	1180.8	1746.5
2	1381.9	777.2
3	1617.3	898.2
4	1892.8	1039.8
5	2082.1	1137.1
6	2290.3	1244.1
7	2519.3	1361.8
8	2771.3	1491.3
9	3048.4	1633.7
10	3353.2	1790.4
11	3688.6	1962.8
12	4057.4	2152.4
13	4463.2	2360.9
14	4909.5	2590.3
15	5400.4	2842.7
16	5940.5	3120.3
17	6534.5	3425.6
18	7188.0	3761.5
19	7906.8	4131.0
20	8697.5	4537.4

ON NET CASH INCOME

ROI= 57.26 %

PAYBACK= 2.1 YEARS

ON NET CASH FLOW

ROI= 46.07 %

PAYBACK= 2.2 YEARS

CASE II +25% CAP COST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
 ELECTRIC CONSUMPTION, KWH/YR -19868
 CHEMICAL COST (YR 1), \$ 5.712
 CAPITAL COST, \$ 3440.9
 INTANGIBLE DRILLING COST, \$ 1442.4
 TAX CREDIT, \$ 639.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-68.8	ELECTRICITY	988.0
MAINTENANCE	-103.2	CHEMICALS	-5.7
GAS SAVINGS	336.1	NET CASH INCOME	1146.4
INTANG DRILL COST	-1442.4	DEPRECIATION	-172.0
TAXABLE INCOME	-467.9	TAX CREDIT	639.8
INCOME TAX	867.2	NET CASH FLOW	2013.7

YEAR	NET CASH INCOME	NET CASH FLOW
1	1146.4	2013.7
2	1344.1	774.5
3	1575.7	893.5
4	1847.0	1032.9
5	2031.7	1127.9
6	2234.9	1232.3
7	2458.4	1347.2
8	2704.2	1473.5
9	2974.6	1612.5
10	3272.1	1765.4
11	3599.3	1933.6
12	3959.2	2118.6
13	4355.2	2322.1
14	4790.7	2546.0
15	5269.8	2792.2
16	5796.7	3063.1
17	6376.4	3361.1
18	7014.1	3688.8
19	7715.5	4049.3
20	8487.0	4445.9

ON NET CASH INCOME

ROI= 47.17 %

PAYBACK= 2.6 YEARS

ON NET CASH FLOW

ROI= 39.18 %

PAYBACK= 2.7 YEARS

CASE III -25% CAP CST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1
 PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
 ELECTRIC CONSUMPTION, KWH/YR -18300
 CHEMICAL COST (YR 1), \$ 0
 CAPITAL COST, \$ 567
 INTANGIBLE DRILLING COST, \$ 0
 TAX CREDIT, \$ 139.95

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-11.3	ELECTRICITY	910.0
MAINTENANCE	-17.0	CHEMICALS	0.0
GAS SAVINGS	-437.2	NET CASH INCOME	444.4
INTANG DRILL COST	0.0	DEPRECIATION	-28.3
TAXABLE INCOME	416.1	TAX CREDIT	139.9
INCOME TAX	-62.2	NET CASH FLOW	382.1

YEAR	NET CASH INCOME	NET CASH FLOW
1	444.4	382.1
2	490.7	266.0
3	539.6	291.1
4	590.8	317.4
5	649.9	347.8
6	714.9	381.2
7	786.4	417.9
8	865.0	458.4
9	951.5	502.8
10	1046.7	551.7
11	1151.3	605.5
12	1266.5	664.7
13	1393.1	729.8
14	1532.5	801.4
15	1685.7	880.2
16	1854.3	966.9
17	2039.7	1062.2
18	2243.7	1167.0
19	2468.1	1282.3
20	2714.9	1409.2

ON NET CASH INCOME
 ROI= 88.47 %
 PAYBACK= 1.2 YEARS

ON NET CASH FLOW
 ROI= 60.05 %
 PAYBACK= 1.6 YEARS

CASE III BASE CAP CST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
 ELECTRIC CONSUMPTION, KWH/YR -18300
 CHEMICAL COST (YR 1), \$ 0
 CAPITAL COST, \$ 756
 INTANGIBLE DRILLING COST, \$ 0
 TAX CREDIT, \$ 186.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-15.1	ELECTRICITY	910.0
MAINTENANCE	-22.6	CHEMICALS	0.0
GAS SAVINGS	-437.2	NET CASH INCOME	435.0
INTANG DRILL COST	0.0	DEPRECIATION	-37.8
TAXABLE INCOME	397.2	TAX CREDIT	186.6
INCOME TAX	-6.4	NET CASH FLOW	428.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	435.0	428.5
2	480.3	265.2
3	528.2	289.8
4	578.2	315.6
5	636.0	345.3
6	699.7	378.0
7	769.6	413.9
8	846.6	453.5
9	931.3	497.0
10	1024.4	544.9
11	1126.8	597.5
12	1239.5	655.5
13	1363.5	719.2
14	1499.8	789.3
15	1649.8	866.4
16	1814.8	951.2
17	1996.3	1044.4
18	2195.9	1147.1
19	2415.5	1259.9
20	2657.1	1384.1

ON NET CASH INCOME
 ROI= 67.58 %
 PAYBACK= 1.6 YEARS

ON NET CASH FLOW
 ROI= 47.74 %
 PAYBACK= 2.2 YEARS

CASE III +25% CAP CST

RUN NO. 1

GAS ESC = 20 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
ELECTRIC CONSUMPTION, KWH/YR -18300
CHEMICAL COST (YR 1), \$ 0
CAPITAL COST, \$ 945
INTANGIBLE DRILLING COST, \$ 0
TAX CREDIT, \$ 233.25

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.472	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-18.9	ELECTRICITY	910.0
MAINTENANCE	-28.3	CHEMICALS	0.0
GAS SAVINGS	-437.2	NET CASH INCOME	425.5
INTANG DRILL COST	0.0	DEPRECIATION	-47.2
TAXABLE INCOME	378.3	TAX CREDIT	233.2
INCOME TAX	49.3	NET CASH FLOW	474.9

YEAR	NET CASH INCOME	NET CASH FLOW
1	425.5	474.9
2	469.9	264.5
3	516.7	288.5
4	565.6	313.7
5	622.2	342.8
6	684.4	374.7
7	752.9	409.9
8	828.2	448.6
9	911.0	491.2
10	1002.1	538.0
11	1102.3	589.5
12	1212.6	646.2
13	1333.8	708.5
14	1467.2	777.1
15	1613.9	852.5
16	1775.3	935.5
17	1952.9	1026.7
18	2148.2	1127.1
19	2363.0	1237.5
20	2599.3	1359.0

ON NET CASH INCOME
ROI= 55.02 %
PAYBACK= 2.0 YEARS

ON NET CASH FLOW
ROI= 40.10 %
PAYBACK= 2.7 YEARS

GENERAL DATA APPLICABLE TO ALL CASES

GAS ESC = 25 %

FIRST YEAR NAT.GAS COST, \$/MMBTU	5.938
FIRST YEAR ELECTRICITY COST, \$/KWH	0.049
TAX & INSURANCE, % OF CAPITAL COST	2.0
MAINTENANCE, % OF CAPITAL COST	3.0
INCOME TAX, % OF TAXABLE INCOME	48.6
NUMBER OF PLANT LIFE CASES	1
PLANT LIFE, YEARS	20

NUMBER OF NAT. GAS CASES = 1

NAT. GAS ESCALATION BY YEAR, IN PERCENT

YEAR	CASE 1
------	--------

2	25
---	----

3	25
---	----

4	25
---	----

5	12
---	----

ESCALATION RATE IS CONSTANT THEREAFTER

ELECTRICITY ESCALATION BY YEAR, IN PERCENT

YEAR	RATE
------	------

2	15
---	----

3	15
---	----

4	15
---	----

5	10
---	----

ESCALATION RATE IS CONSTANT THEREAFTER

ANNUAL ESCALATION RATES, IN PERCENT, FOR...

TAXES AND INSURANCE =	10
-----------------------	----

MAINTENANCE =	10
---------------	----

CHEMICAL COST =	10
-----------------	----

CASE III -25% CAP CST

RUN NO. 1

GAS ESC = 25 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
 ELECTRIC CONSUMPTION, KWH/YR -18300
 CHEMICAL COST (YR 1), \$ 0
 CAPITAL COST, \$ 567
 INTANGIBLE DRILLING COST, \$ 0
 TAX CREDIT, \$ 139.95

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.938	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-11.3	ELECTRICITY	910.0
MAINTENANCE	-17.0	CHEMICALS	0.0
GAS SAVINGS	-474.4	NET CASH INCOME	407.2
INTANG DRILL COST	0.0	DEPRECIATION	-28.3
TAXABLE INCOME	378.9	TAX CREDIT	139.9
INCOME TAX	-44.2	NET CASH FLOW	363.0

YEAR	NET CASH INCOME	NET CASH FLOW
1	407.2	363.0
2	422.3	230.8
3	427.9	233.7
4	419.6	229.5
5	438.5	239.1
6	456.2	248.3
7	472.6	256.6
8	486.8	264.0
9	498.4	269.9
10	506.5	274.1
11	510.2	276.0
12	508.4	275.1
13	499.8	270.6
14	482.9	262.0
15	456.0	248.1
16	416.9	228.1
17	363.4	200.6
18	292.7	164.2
19	201.4	117.3
20	86.0	58.0

ON NET CASH INCOME
 ROI= 74.13 %
 PAYBACK= 1.3 YEARS

ON NET CASH FLOW
 ROI= 49.18 %
 PAYBACK= 1.8 YEARS

CASE III BASE CAP CST

RUN NO. 1

GAS ESC = 25 %

NAT. GAS ESCALATION CASE NO. 1
 PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
 ELECTRIC CONSUMPTION, KWH/YR -18300
 CHEMICAL COST (YR 1), \$ 0
 CAPITAL COST, \$ 756
 INTANGIBLE DRILLING COST, \$ 0
 TAX CREDIT, \$ 186.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.938	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-15.1	ELECTRICITY	910.0
MAINTENANCE	-22.6	CHEMICALS	0.0
GAS SAVINGS	-474.4	NET CASH INCOME	397.8
INTANG DRILL COST	0.0	DEPRECIATION	-37.8
TAXABLE INCOME	360.0	TAX CREDIT	186.6
INCOME TAX	11.6	NET CASH FLOW	409.4

YEAR	NET CASH INCOME	NET CASH FLOW
1	397.8	409.4
2	411.9	230.1
3	416.4	232.4
4	407.1	227.6
5	424.6	236.6
6	441.0	245.0
7	455.8	252.6
8	468.4	259.1
9	478.1	264.1
10	484.2	267.2
11	485.7	268.0
12	481.4	265.8
13	470.1	260.0
14	450.3	249.8
15	420.1	234.3
16	377.5	212.4
17	320.0	182.8
18	244.9	144.2
19	148.9	94.9
20	28.2	32.9

ON NET CASH INCOME
 ROI= 54.61 %
 PAYBACK= 1.8 YEARS

ON NET CASH FLOW
 ROI= 37.51 %
 PAYBACK= 2.5 YEARS

CASE III +25% CAP CST

RUN NO. 1

GAS ESC = 25 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR -79.9
ELECTRIC CONSUMPTION, KWH/YR -18300
CHEMICAL COST (YR 1), \$ 0
CAPITAL COST, \$ 945
INTANGIBLE DRILLING COST, \$ 0
TAX CREDIT, \$ 233.25

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	5.938	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-18.9	ELECTRICITY	910.0
MAINTENANCE	-28.3	CHEMICALS	0.0
GAS SAVINGS	-474.4	NET CASH INCOME	388.3
INTANG DRILL COST	0.0	DEPRECIATION	-47.2
TAXABLE INCOME	341.1	TAX CREDIT	233.2
INCOME TAX	67.4	NET CASH FLOW	455.8

YEAR	NET CASH INCOME	NET CASH FLOW
1	388.3	455.8
2	401.5	229.3
3	405.0	231.1
4	394.5	225.7
5	410.8	234.1
6	425.8	241.8
7	439.1	248.6
8	450.0	254.2
9	457.9	258.3
10	461.9	260.4
11	461.2	260.0
12	454.5	256.5
13	440.5	249.3
14	417.7	237.6
15	384.2	220.4
16	338.0	196.7
17	276.6	165.1
18	197.1	124.3
19	96.3	72.5
20	- 29.5	7.7

ON NET CASH INCOME
ROI= 42.70 %
PAYBACK= 2.3 YEARS

ON NET CASH FLOW
ROI= 30.12 %
PAYBACK= 3.1 YEARS

GENERAL DATA APPLICABLE TO ALL CASES

GAS ESC = 30 %

FIRST YEAR NAT. GAS COST, \$/MMBTU	6.422
FIRST YEAR ELECTRICITY COST, \$/KWH	0.049
TAX & INSURANCE, % OF CAPITAL COST	2.0
MAINTENANCE, % OF CAPITAL COST	3.0
INCOME TAX, % OF TAXABLE INCOME	48.6
NUMBER OF PLANT LIFE CASES	1
PLANT LIFE, YEARS	20

NUMBER OF NAT. GAS CASES = 1

NAT. GAS ESCALATION BY YEAR, IN PERCENT

YEAR	CASE 1
2	30
3	30
4	30
5	15

ESCALATION RATE IS CONSTANT THEREAFTER

ELECTRICITY ESCALATION BY YEAR, IN PERCENT

YEAR	RATE
2	15
3	15
4	15
5	10

ESCALATION RATE IS CONSTANT THEREAFTER

ANNUAL ESCALATION RATES, IN PERCENT, FOR...

TAXES AND INSURANCE =	10
MAINTENANCE =	10
CHEMICAL COST =	10

CASE I -25% CAP COST

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
ELECTRIC CONSUMPTION, KWH/YR -4218
CHEMICAL COST (YR 1), \$ 5.259
CAPITAL COST, \$ 1497.8
INTANGIBLE DRILLING COST, \$ 865.5
TAX CREDIT, \$ 244

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-29.9	ELECTRICITY	209.7
MAINTENANCE	-44.9	CHEMICALS	-5.2
GAS SAVINGS	282.9	NET CASH INCOME	412.5
INTANG DRILL COST	-865.5	DEPRECIATION	-74.8
TAXABLE INCOME	-527.8	TAX CREDIT	244.0
INCOME TAX	500.5	NET CASH FLOW	913.0

YEAR	NET CASH INCOME	NET CASH FLOW
1	412.5	913.0
2	520.9	304.1
3	658.6	374.9
4	833.9	465.0
5	948.4	523.9
6	1079.0	591.0
7	1228.0	667.6
8	1398.1	755.0
9	1592.3	854.8
10	1814.0	968.8
11	2067.3	1099.0
12	2356.8	1247.7
13	2687.5	1417.8
14	3065.6	1612.1
15	3497.9	1834.3
16	3992.3	2088.4
17	4557.9	2379.1
18	5204.9	2711.7
19	5945.3	3092.3
20	6792.8	3527.9

ON NET CASH INCOME
ROI= 47.26 %
PAYBACK= 2.8 YEARS

ON NET CASH FLOW
ROI= 41.40 %
PAYBACK= 2.7 YEARS

CASE I BASE CAP COST

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
ELECTRIC CONSUMPTION, KWH/YR -4218
CHEMICAL COST (YR 1), \$ 5.259
CAPITAL COST, \$ 1997.1
INTANGIBLE DRILLING COST, \$ 1154
TAX CREDIT, \$ 325.3

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-39.9	ELECTRICITY	209.7
MAINTENANCE	-59.9	CHEMICALS	-5.2
GAS SAVINGS	282.9	NET CASH INCOME	387.6
INTANG DRILL COST	-1154.0	DEPRECIATION	-99.8
TAXABLE INCOME	-866.2	TAX CREDIT	325.3
INCOME TAX	746.2	NET CASH FLOW	1133.9

YEAR	NET CASH INCOME	NET CASH FLOW
1	387.6	1133.9
2	493.4	302.1
3	628.4	371.5
4	800.7	460.1
5	911.9	517.2
6	1038.8	582.5
7	1183.8	657.0
8	1349.5	742.1
9	1538.8	839.4
10	1755.2	950.7
11	2002.6	1077.8
12	2285.5	1223.3
13	2609.2	1389.6
14	2979.4	1579.9
15	3403.1	1797.7
16	3888.1	2047.0
17	4443.2	2332.3
18	5078.7	2659.0
19	5806.5	3033.1
20	6640.1	3461.5

ON NET CASH INCOME

ROI= 38.02 %

PAYBACK= 3.6 YEARS

ON NET CASH FLOW

ROI= 34.48 %

PAYBACK= 3.4 YEARS

CASE I +25% CAAP COS

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 44.06
ELECTRIC CONSUMPTION, KWH/YR -4218
CHEMICAL COST (YR 1), \$ 5.259
CAPITAL COST, \$ 2496.3
INTANGIBLE DRILLING COST, \$ 1442.4
TAX CREDIT, \$ 406.6

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-49.9	ELECTRICITY	209.7
MAINTENANCE	-74.8	CHEMICALS	-5.2
GAS SAVINGS	282.9	NET CASH INCOME	362.6
INTANG DRILL COST	-1442.4	DEPRECIATION	-124.8
TAXABLE INCOME	-1204.5	TAX CREDIT	406.6
INCOME TAX	992.0	NET CASH FLOW	1354.6

YEAR	NET CASH INCOME	NET CASH FLOW
1	362.6	1354.6
2	465.9	300.1
3	598.2	368.1
4	767.5	455.1
5	875.3	510.6
6	998.6	573.9
7	1139.6	646.4
8	1300.8	729.3
9	1485.3	824.1
10	1696.3	932.5
11	1937.8	1056.7
12	2214.3	1198.8
13	2530.8	1361.5
14	2893.3	1547.8
15	3308.3	1761.1
16	3783.8	2005.5
17	4328.5	2285.5
18	4952.6	2606.3
19	5667.8	2973.9
20	6487.5	3395.2

ON NET CASH INCOME
ROI= 32.14 %
PAYBACK= 4.3 YEARS

ON NET CASH FLOW
ROI= 29.90 %
PAYBACK= 4.0 YEARS

CASE II -25% CAP COST

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 2064.5
INTANGIBLE DRILLING COST, \$ 865.5
TAX CREDIT, \$ 383.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-41.2	ELECTRICITY	988.0
MAINTENANCE	-61.9	CHEMICALS	-5.7
GAS SAVINGS	394.5	NET CASH INCOME	1273.6
INTANG DRILL COST	-865.5	DEPRECIATION	-103.2
TAXABLE INCOME	304.9	TAX CREDIT	383.8
INCOME TAX	235.5	NET CASH FLOW	1509.2

YEAR	NET CASH INCOME	NET CASH FLOW
1	1273.6	1509.2
2	1529.3	836.2
3	1841.6	996.7
4	2224.5	1193.5
5	2490.3	1330.2
6	2789.2	1483.8
7	3125.4	1656.6
8	3503.9	1851.1
9	3930.1	2070.2
10	4410.3	2317.0
11	4951.6	2595.2
12	5562.0	2909.0
13	6250.8	3263.1
14	7028.4	3662.7
15	7906.6	4114.1
16	8898.9	4624.2
17	10020.7	5200.8
18	11289.4	5852.9
19	12725.1	6590.8
20	14350.3	7426.2

ON NET CASH INCOME
ROI= 79.74 %
PAYBACK= 1.5 YEARS

ON NET CASH FLOW
ROI= 61.35 %
PAYBACK= 1.6 YEARS

CASE II BASE CAP COST

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1
PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 2752.7
INTANGIBLE DRILLING COST, \$ 1154
TAX CREDIT, \$ 511.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-55.0	ELECTRICITY	988.0
MAINTENANCE	-82.5	CHEMICALS	-5.7
GAS SAVINGS	394.5	NET CASH INCOME	1239.2
INTANG DRILL COST	-1154.0	DEPRECIATION	-137.6
TAXABLE INCOME	-52.3	TAX CREDIT	511.8
INCOME TAX	537.2	NET CASH FLOW	1776.5

YEAR	NET CASH INCOME	NET CASH FLOW
1	1239.2	1776.5
2	1491.4	833.5
3	1800.0	992.1
4	2178.7	1186.7
5	2439.9	1321.0
6	2733.8	1472.0
7	3064.5	1642.0
8	3436.8	1833.4
9	3856.3	2049.0
10	4329.1	2292.0
11	4862.3	2566.1
12	5463.8	2875.3
13	6142.8	3224.3
14	6909.6	3618.4
15	7775.9	4063.7
16	8755.1	4567.0
17	9862.6	5136.2
18	11115.5	5780.2
19	12533.7	6509.2
20	14139.8	7334.7

ON NET CASH INCOME
ROI= 62.49 %
PAYBACK= 2.0 YEARS

ON NET CASH FLOW
ROI= 50.09 %
PAYBACK= 2.1 YEARS

CASE II +25% CAP COST

RUN NO. 1

GAS ESC = 30 %

NAT. GAS ESCALATION CASE NO. 1

PLANT LIFE, YRS = 20

FOLLOWING ARE IN THOUSANDS...

NAT. GAS SAVINGS, MMBTU/YR 61.44
ELECTRIC CONSUMPTION, KWH/YR -19868
CHEMICAL COST (YR 1), \$ 5.712
CAPITAL COST, \$ 3440.9
INTANGIBLE DRILLING COST, \$ 1442.4
TAX CREDIT, \$ 639.8

FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNLESS OTHERWISE NOTED)

NAT. GAS, \$/MMBTU	6.422	ELECTRICITY, \$/KWH	0.049
TAXES & INSURANCE	-68.8	ELECTRICITY	988.0
MAINTENANCE	-103.2	CHEMICALS	-5.7
GAS SAVINGS	394.5	NET CASH INCOME	1204.8
INTANG DRILL COST	-1442.4	DEPRECIATION	-172.0
TAXABLE INCOME	-409.5	TAX CREDIT	639.8
INCOME TAX	838.8	NET CASH FLOW	2043.7

YEAR	NET CASH INCOME	NET CASH FLOW
1	1204.8	2043.7
2	1453.6	830.7
3	1758.4	987.4
4	2132.9	1179.9
5	2389.5	1311.8
6	2678.3	1460.3
7	3003.5	1627.4
8	3369.8	1815.7
9	3782.6	2027.8
10	4248.0	2267.1
11	4773.1	2536.9
12	5365.7	2841.5
13	6034.8	3185.5
14	6790.8	3574.1
15	7645.2	4013.2
16	8611.4	4509.9
17	9704.5	5071.7
18	10941.6	5707.6
19	12342.4	6427.6
20	13929.4	7243.3

ON NET CASH INCOME
ROI= 51.97 %
PAYBACK= 2.4 YEARS

ON NET CASH FLOW
ROI= 42.95 %
PAYBACK= 2.5 YEARS

APPENDIX F

Economic Analysis Computer Listing

This Appendix contains a listing of the computer program used to calculate rates of return and payback period for this study. The program was written in BASIC language for a Wang 2200 Computer.

```

10 COM P(4),S(4,40),R(5),C(40),N1(2,40)
20 COM F,E,T,M,X,L,O,B1,B2,B3,M1,Q1(2),Q2(2)
30 COM B$
40 SELECT PRINT 005
50 PRINT "ENTER COMMON IDENTIFIER FOR ALL RUNS"
60 INPUT B$
70 PRINT "ENTER FIRST YEAR NATURAL GAS COST, $/MMBTU"
80 INPUT F
90 PRINT "ENTER FIRST YEAR ELECTRICITY COST,$/KWH"
100 INPUT E
110 PRINT "ENTER TAX & INSURANCE, % OF CAPITAL COST"
120 INPUT T
130 PRINT "ENTER MAINTENANCE, % OF CAPITAL COST"
140 INPUT M
150 PRINT "ENTER INCOME TAX, % OF TAXABLE INCOME"
160 INPUT X
170 PRINT "ENTER NO. OF PLANT LIFE CASES (4 MAX)"
180 INPUT L
190 IF L 1 4 THEN 170
200 IF L 11 THEN 170
210 PRINT USING 220, L
220 %ENTER## PLANT LIVES
230 FOR I= 1 TO L
240 INPUT P(I)
250 NEXT I
260 PRINT "ENTER NO. OF NATURAL GAS COST CASES (4 MAX)"
270 INPUT O
280 IF O 1 1 THEN 270
290 IF O 1 4 THEN 270
300 PRINT "FOR EACH NAT GAS COST CASE ENTER ESCALATION"
310 PRINT " RATE, IN PERCENT, STARTING WITH YEAR 2."
320 PRINT "WHEN ESCALATION RATE IS TO REMAIN CONSTANT,"
330 PRINT " ENTER 999 FOR THAT YEAR'S RATE."
340 FOR I= 1 TO O
350 PRINT USING 360, I
360 %ENTER DATA FOR CASE##
370 S(I,1)=0
380 FOR J= 2 TO 40
390 INPUT S(I,J)
400 IF S(I,J) = 999 THEN 430
410 NEXT J
420 GOTO 480
430 R(I)=J-1
440 A=J-1
450 FOR K= J TO 40
460 S(I,K)=S(I,A)
470 NEXT K
480 NEXT I
490 PRINT "ENTER ELECTRICITY ESCALATION, IN PERCENT,"
500 PRINT " STARTING WITH YEAR 2."
510 PRINT "WHEN ESCALATION RATE IS TO REMAIN CONSTANT,"
520 PRINT " ENTER 999 FOR THAT YEAR'S RATE."
530 C(1)=0
540 FOR I=2 TO 40
550 INPUT C(I)
560 IF C(I) = 999 THEN 590
570 NEXT I
580 GOTO 640
590 R(5)=I-1

```

```

600 A=I-1
610 FOR K=I TO 40
620 C(K)=C(A)
630 NEXT K
640 PRINT "ENTER ANNUAL ESCALATION RATES, IN PERCENT, FOR..."
650 PRINT "      TAXES AND INSURANCE"
660 INPUT B1
670 PRINT "      MAINTENANCE"
680 INPUT B2
690 PRINT "      CHEMICAL COST"
700 INPUT B3
710 STOP "POSITION PAPER"
720 SELECT PRINT 211(80)
730 PRINT "  GENERAL DATA APPLICABLE TO ALL CASES      ";B$
740 PRINT
750 PRINT USING 760,F
760 %FIRST YEAR NAT.GAS COST, $/MMBTU      ###
770 PRINT USING 780, E
780 %FIRST YEAR ELECTRICITY COST, $/KWH      ###
790 PRINT USING 800, T
800 %TAX & INSURANCE, % OF CAPITAL COST      ##.#
810 PRINT USING 820, M
820 %MAINTENANCE, % OF CAPITAL COST      ##.#
830 PRINT USING 840,X
840 %INCOME TAX, % OF TAXABLE INCOME      ##.#
850 PRINT USING 860,L
860 %NUMBER OF PLANT LIFE CASES      #
870 PRINT "PLANT LIFE, YEARS"
880 FOR I=1 TO L
890 PRINT P(I)
900 NEXT I
910 PRINT
920 PRINT USING 930, O
930 %NUMBER OF NAT. GAS CASES = #
940 PRINT "NAT. GAS ESCALATION BY YEAR, IN PERCENT"
950 PRINT "YEAR";
960 FOR J = 1 TO O
970 PRINT USING 980, J;
980 %      CASE #
990 NEXT J
1000 PRINT
1010 I=0
1020 FOR J=1 TO 4
1030 IF R(J) ! I THEN 1050
1040 I=R(J)
1050 NEXT J
1060 FOR J=2 TO I
1070 PRINT J;
1080 FOR J1=1 TO O
1090 PRINT USING 1100, S(J1,J);
1100 %      ##
1110 NEXT J1
1120 PRINT
1130 NEXT J
1140 PRINT "ESCALATION RATE IS CONSTANT THEREAFTER"
1150 PRINT
1160 PRINT "ELECTRICITY ESCALATION BY YEAR, IN PERCENT"
1170 PRINT "YEAR", "RATE"
1180 J=R(5)
1190 FOR I= 2 TO J

```

```

1200 PRINT I,C(I)
1210 NEXT I
1220 PRINT "ESCALATION RATE IS CONSTANT THEREAFTER"
1230 PRINT
1240 PRINT "ANNUAL ESCALATION RATES, IN PERCENT, FOR..."
1250 PRINT "    TAXES AND INSURANCE = ",B1
1260 PRINT "    MAINTENANCE = ",B2
1270 PRINT "    CHEMICAL COST = ",B3
1280 STOP "POSITION PAPER"
1290 LOAD
1300 END

```

```

10  COM P(4),S(4,40),R(5),C(40),M1(2,40)
20  COM F,E,T,M,X,L,O,B1,B2,B3,M1,Q1(2),Q2(2)
30  COM B$
40  DIM Z1$(5),Z2(5),Z3(5),Z4(5),Z5(5),Z6(5),Z7(5)
50  SELECT PRINT 005
60  K9=0
70  K9=K9+1
80  PRINT "ENTER CASE DESCRIPTION"
90  INPUT A$
100 PRINT "ENTER ALL THE FOLLOWING IN THOUSANDS..."
110 PRINT
120 PRINT "ENTER NAT. GAS SAVINGS, MBTU/YR"
130 INPUT D1
140 PRINT "ENTER ELECTRIC CONSUMPTION, KWH/YR"
150 INPUT D2
160 PRINT "ENTER CHEMICAL COST, $"
170 INPUT M1
180 PRINT "ENTER CAPITAL COST, $"
190 INPUT D3
200 PRINT "ENTER INTANGIBLE DRILLING COST, $"
210 INPUT D4
220 PRINT "ENTER TAX CREDIT, $"
230 INPUT D5
240 Z1$(K9)=A$
250 Z2(K9)=D1
260 Z3(K9)=D2
270 Z4(K9)=M1
280 Z5(K9)=D3
290 Z6(K9)=D4
300 Z7(K9)=D5
310 IF K9 = 5 THEN 350
320 PRINT "IF ADDITIONAL CASES, ENTER    YES    "
330 INPUT A1$
340 IF A1$ = "YES" THEN 70
350 SELECT PRINT 211(80)
360 K8=K9
370 FOR K9= 1 TO K8
380 A$=Z1$(K9)
390 D1=Z2(K9)

```

```

400 D2=Z3(K9)
410 M1=Z4(K9)
420 D3=Z5(K9)
430 D4=Z6(K9)
440 D5=Z7(K9)
450 K=0
460 FOR I=1 TO 0
470 FOR J=1 TO L
480 K=K+1
490 PRINT "CASE ";A$, "RUN NO. ";K;"          ";B$
500 PRINT
510 PRINT "NAT. GAS ESCALATION CASE NO. ";I
520 N=P(J)
530 PRINT "PLANT LIFE, YRS = ";N
540 PRINT
550 PRINT "FOLLOWING ARE IN THOUSANDS..."
560 PRINT "NAT. GAS SAVINGS, MMBTU/YR          ";D1
570 PRINT "ELECTRIC CONSUMPTION, KWH/YR        ";D2
580 PRINT "CHEMICAL COST (YR 1), $             ";M1
590 PRINT "CAPITAL COST, $                     ";D3
600 PRINT "INTANGIBLE DRILLING COST, $         ";D4
610 PRINT "TAX CREDIT, $                       ";D5
620 PRINT
630 L1=N
640 REM L1=PLANT LIFE, YEARS
650 REM SETUP FIRST LINE
660 REM G1 IS FIRST COLUMN OF OUTPUT SHEET
670 REM G9 IS NINTH COLUMN
680 REM H1 IS TENTH COLUMN
690 REM ETC
700 G1=1
710 G2=F
720 G3=E
730 G5=-D3*T/100
740 G6=-G3*D2
750 G7=-D3*M/100
760 G8=-M1
770 G9=G2*D1
780 H1=G5+G6+G7+G8+G9
790 H2=-D4
800 H3=-D3/L1
810 H4=H1+H2+H3
820 H5=D5
830 H6=-H4*X/100
840 H6=H6+H5
850 H7=H1+H6
860 PRINT "FIRST YEAR COSTS FOLLOW (IN THOUSANDS OF DOLLARS, UNL
ESS OTHERWISE NOTED)"
870 PRINT USING 880,G2,G3
880 %NAT. GAS,$/MMBTU      -####.###          ELECTRICITY, $/KWH      -
####.###
890PRINT USING 900, G5,G6
900 %TAXES & INSURANCE     -####.#           ELECTRICITY          -
####.#
910 PRINT USING 920, G7,G8
920 %MAINTENANCE           -####.#           CHEMICALS            -
####.#
930 PRINT USING 940, G9,H1
940 %GAS SAVINGS           -####.#           NET CASH INCOME      -
####.#

```



```

950 PRINT USING 960, H2, H3
960 %INTANG DRILL COST -####.#          DEPRECIATION          -
####.#
970 PRINT USING 980, H4, H5
980 %TAXABLE INCOME -####.#          TAX CREDIT          -
####.#
990 PRINT USING 1000, H6, H7
1000 %INCOME TAX -####.#          NET CASH FLOW
-####.#
1010 PRINT
1020 PRINT USING 1040
1030 PRINT USING 1050
1040 %YEAR          NET CASH INCOME          NET CASH FLOW
1050 %-----          -----
1060 I2=1
1070 PRINT USING 1080, I2, H1, H7
1080 % ##          #####.#          #####.#
1090 REM NOW FOR REMAINING YEARS
1100 N1(1,1)=H1
1110 N1(2,1)=H7
1120 FOR I2 = 2 TO L1
1130 G2=G2*(1+S(I,I2)/100)
1140 G3=G3*(1+C(I2)/100)
1150 G5=G5*(1+B1/100)
1160 G6=-G3*D2
1170 G7=G7*(1+B2/100)
1180 G8=G8*(1+B3/100)
1190 G9=G2*D1
1200 H1=G5+G6+G7+G8+G9
1210 H4=H1+H3
1220 H6=-H4*X/100
1230 H7=H1+H6
1240 N1(1,I2)=H1
1250 N1(2,I2)=H7
1260 PRINT USING 1080, I2, H1, H7
1270 NEXT I2
1280 PRINT
1290 REM CALC ROI
1300 FOR I1 = 1 TO 2
1310 I2=1
1320 I8=5
1330 T1=0
1340 FOR I3 = 1 TO L1
1350 T1=T1+N1(I1,I3)/((1+I8/100)1/2I3)
1360 NEXT I3
1370 IF I2 = 2 THEN 1430
1380 T7=T1
1390 I7=I8
1400 I2=2
1410 I8=10
1420 GOTO 1330
1430 T8=T1
1440 I9=I7+(D3-T7)*(I8-I7)/(T8-T7)
1450 IF ABS(I9-I8) > 0.001 THEN 1500
1460 T7=T8
1470 I7=I8
1480 I8=I9
1490 GOTO 1330

```

```

1500 Q1(I1)=I8
1510 NEXT I1
1520 REM NOW CALC PAYBACK
1530 FOR I1=1 TO 2
1540 T1=0
1550 I2=1
1560 T1=T1+N1(I1,I2)
1570 IF T1 1 = D3 THEN 1600
1580 I2=I2+1
1590 GOTO 1560
1600 Q2(I1)=(I2-1)+(D3-(T1-N1(I1,I2)))/N1(I1,I2)
1610 NEXT I1
1620 PRINT "      ";
1630 PRINT "ON NET CASH INCOME      ON NET CASH FLOW"
1640 PRINT "      ";
1650 PRINT USING 1660, Q1(1),Q1(2)
1660      % ROI= ##.## %      ROI= ##.## %
1670 PRINT "      ";
1680 PRINT USING 1690, Q2(1),Q2(2)
1690      %PAYBACK= ##.## YEARS      PAYBACK= ##.## YEARS
1700 I1=66-28-N
1710 FOR I3= 1 TO I1
1720 PRINT
1730 NEXT I3
1740 NEXT J
1750 NEXT I
1760 NEXT K9
1770 GOTO 50
1780 END

```