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EXPLORATION, THE ECONOMIC STRATEGIES

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Abstract Exploration for a geothermal reservoir is capital-intensive, and requires planning and significant capital. The objectives of exploration are to locate, analyze, and acquire the areas that can produce economic and useful quantities of geothermal energy. Evaluation of the risks of finding adequate producible and useable energy with the available techniques and funds provides the foundation for the exploration plans. Exploration wells now cost about $200 per foot drilled. Development of a 50MW field and plant requires more than 76 million dollars. A direct use development requires a minimum of $1,000,000 if it involves a new industrial installation. A development must provide more than 25% rate of return of return on the investment to compete with low risk investments.

I. Introduction Exploration for the location of a geothermal reservoir is capital-intensive, requires expert planning, and long times from initial expenditure until positive income is achieved. The development of a geothermal field to the point of utilization of the geothermal reserve requires extensive engineering, approximately two years in negotiation and planning with the energy user and governmental agencies. Capital amounts of 30 to 50 million dollars per 50MW plant will be needed. Direct use projects may require five to ten percent of this amount.

The objectives of the exploration process are to locate, analyze, acquire the rights to develop and evaluate areas that can produce economic and useful quantities of geothermal energy.

The most important factor in converting a resource into a reserve is how the individuals that are actively dedicated to exploration for discovery and development attack the problem. The key to successful reserve finding and development is the quality of the people assigned to the task. These people have a large variety of experience and techniques to use in their exploration programs.

The exploration process components blend concurrently to achieve these objectives. Work necessary to make this possible utilizes the following activities (Table I).

Geology and Geophysics provide the base for defining broad areas of concentration and site specific selection of drilling locations. Area analysis of natural resource exploration activity includes identification of lands for acquisition of development rights (or joint ventures). Understanding the political philosophy of governmental entities controlling resource development is essential for effective exploration.

Evaluation of the risks of finding accumulations of adequate size of producible and useable energy with the available techniques and funds of money allows the explorationist to make a realistic formulation of the exploration plans. Geology, geophysics, drilling and formation evaluation establish the parameters used in a practical evaluation.

Financing establishes the framework of an exploration program. This framework is a budget when forecast expenditures are related to the time of expected work increments versus the availability of funds and manpower at given units of time.

Combining work program budgets with forecast revenue timing allows the preparation of an initial cash flow analysis to measure the economic attractiveness of the exploration program. This analysis provides a strong input into the decision to continue with the exploration program until it results in a development program.

Table II illustrates exploration techniques and associated costs. The overall amount of money (per successful prospect) required is 3 million to 6.6 million dollars. This provides for limited failure and followup costs, but does not include other exploration prospect failures and their land costs. Low and moderate temperature systems may require similar evaluation programs as the high temperature systems suitable for electricity generation and industrial processing.

Financial analyses are made before the initiation of an exploration program and before and after drilling the initial successful well. Confirmation and development plans are site specific. So are economic analysis. The exploration phase should meld into the development phase so the knowledge necessary for efficient development is transferred to the development operation. A "cross feed" benefit is derived for both operations. The explora-

TABLE I

JOBS RELATED TO EXPLORATION PROGRAM

LAND	GEOLOGY & GEOPHYSICS	DRILLING & PRODUCTION
Acquisition, exploration and production rights	Mapping	Access and site construction
Regulations & permits	Regional geology	Drill program design
Public hearings	Prospect definition	Contractor selection
Titles & obligations	Temp. hole program	Drilling supervision
Joint ventures	Well site selection	Testing-performance design
	Bottom hole location	Surface installations
	Coordinate access route	Field & reservoir management
	Formation evaluation	Reserve reports
	Development program	
	Environmental reports	

FINANCE
Data processing
Accounting
Expenditures forecast
Actual expenditures
Banking
Tax assessments
Tax reports

TABLE II

EXPLORATION TECHNIQUES AND APPROXIMATE COSTS

Objective	Technique	Approximate Cost ($)
Heat Source & Plumbing	Geology	$ 20,000
	Microseismicity	15,000
Temperature Regime	Gravity	20,000
	Resistivity	25,000
	Tellurics and magnetotellurics	50,000
	Magnetics	15,000
	Geochemistry (hydrology)	12,000
	Land analysis and permitting	45,000
	Temperature gradient - 20 holes (500' or less)	280,000
	Stratigraphic holes - 4	160,000- 800,000
Reservoir Characteristics	Exploratory and confirmation tests - 3 -	2,800,000-5,000,000
	Reservoir testing	250,000

tion group will develop a realistic target and can evaluate the effectiveness and sequence of tools used to find that particular target. The necessary amount of money can be calculated and dedicated to the search for similar accumulation. Economic analysis requires an actual development plan be formulated.

New contracts for sale of the energy are recognizing the risks and investments of the user and producer of the energy. Most importantly they recognize that a commodity is being sold or purchased. There are relative values among the available types of fossil energy. These values can be equated by recognition of the work to produce the same product. This simple conceptual change allows the user to design more efficient machinery and reduce his energy needs. This same impetus is given the seller (producer) to develop the most efficient productive method for his energy accumulation.

The revenue plan must address: will energy be sold by the BTU, by pounds of fluid produced, or by the product manufactured with the energy? To establish the price for the delivered energy requires expert market analysis, expert analysis of the user's manufacturing process, and expert analysis of how the reservoir will perform for 25 or 30 years. The understanding of the economic benefits derived from producing the energy will produce the most realistic budget to carry out the total exploration plan.

To construct a cash flow analysis the variable factors affecting the rate of return must be identified. The average cost to find a geothermal anomaly is an important factor in the analysis made to determine if an organization should explore. After the discovery has been indicated exploration costs are "sunk" costs and are not of prime importance in the decision of whether to develop the discovered heat concentration. Future costs and returns are the important considerations in deciding whether to proceed with the development of this discovery and/or whether to continue looking for another one.

The objective of the exploration program is reached when the decision is made to begin field development. The decision to develop a geothermal reserve is an economic one made after careful consideration of the costs required to:

1. Confirm the amount of producible and useful energy in the postulated accumulation
2. Develop and operate the energy production system
3. Build the energy utilization equipment or plant
4. Operate the utilization systems and market the product

Basic site specific constraints are involved in determining these costs. The produced energy and the form of its carrier limit the type of energy production system that would be useful and available for reliable operation. Fields producing hot water that flashes in the plant have different development costs than those producing dry steam.

A summary of estimated development costs after exploration expenses for the field supply, power plant, and ancillary equipment for a 50-megawatt hot water flash unit for a reservoir temperature above 400°F is as follows:

TABLE III

50MW HOT WATER FLASH

Production Wells - 12	$ 19,800,000
Injection Wells - 6	9,900,000
Pipelines	2,800,000
Miscellaneous field expense (includes interest and working capital)	9,000,000
Power Plant	35,000,000
	$ 76,500,000

With a schedule of field and plant development the revenue schedules can be forecast. The cost of competitive fuels available in industrial plants in the area served by the geothermal development will establish the maximum unit revenue that can be used in the revenue schedule. With these factors determined a cash flow analysis can be developed. By changing the above factors to their maximum and minimum expected values the economic sensitivity to certain variables can be determined. In this manner factors most likely to affect commerciality are identified and strategies can be developed to insure the project's completion.

Analysis of the profitability of a proposed development requires a price for the energy be forecast. The basic structure of price must provide an attractive rate of return to the prospector. The prospector's risk capital investment and time at risk before income must be minimized. The revenue should reflect the actual value of the energy sold. This value can be estimated by relating the price of oil or coal to an expected price for geothermal energy.

The 1981 price for steam at the Geysers at 27.6 mils per kilowatt hour of electricity generated is well below the price of oil or coal fuels available to a west coast generating plant. An oil fired plant generates about 590 kilowatt hours per $36.00 barrel of fuel oil. This is a fuel cost of 61 mils per kwh. Another way to express this is that the fuel costs $6.43 per million Btu used. Six years hence, with 12% inflation, the 61 mil price for oil fuel will have increased to more than 120 mils per kwh generated.

A base case for the analysis uses conditions similar to those existing at the time of initial cash flow analysis. Therefore, 27.6 mils for sales price from producer to utility is a reasonable beginning. The number of wells estimated to be needed to produce the energy and to inject condensed fluids should be determined using the heat rate of the newest plants using the energy. The original electricity generating plants at the Geysers needed 20 pounds of steam per hour to produce a kilowatt hour of electricity. Table IV shows the more recent plants' characteristic requirements to enable a developer to estimate the number of development wells needed. A similar estimate should be prepared for non-electric uses.

Plant costs for the electricity producer are accelerating similar to Nelson's Price Index For Construction Projects published in the Oil and Gas Journal. PG&E's plant #15, put into operation in 1979, cost approximately $320 per kilowatt including the H_2S removal. Plants designed today for construction three years from now will probably cost $600 per kilowatt. Ecolaire Condenser, Inc. has designed a portable well head heat exchanger plant with an output of 2.6 megawatts. It is estimated this will cost about $600 per KW for temperatures above 400°. This would require a well field capability of 740,000 lbs. of geothermal fluid per hour at 410°F. It would be possible to obtain early income using this system while studying the characteristics of the producing reservoir, to determine its optimum usefulness.

A summary of factors to use in the economic analysis of a steam field exploration target would include the following for 110 MW development:

16 9,000' producing wells at $1,650,000 =

TABLE IV

	PG&E Unit 15	PG&E Unit 16	SMUD SMUDGEO #1
Megawatts Gross	60.00	120.00	72.25
Megawatts Net	57.27	113.43	67.02
Turbine Throttle Flow (lbs/hr)	1.074M	1.906M	950.00M
Net Turbine Steam Rate (lbs/KWH)	18.75	16.80	14.17
Condenser-Pressure in HGA	4.0	3.0	1.5

$26,400,00
2 injector wells at $1,650,000 = $3,300,000
2 Dry holes forecast at $1,635,000 each
Operating costs at 12% of gross revenue
Ad valorum tax 6% of net revenue
Federal & state income tax 50% (includes depreciation and depletion considered directly)
Depletion 15% of net revenue
Depreciation schedule - 15 year straightline
Investment tax credit 20% in year of investment
Makeup wells - one every two years after the 9th year

The plant should be a 110MW that would start up in the middle of the fourth year of the project. The plant would be base loaded and run with an operating factor of 90% generating 7884 hours per year. The capacity factor of 95% would result in 104.5 KWh being generated when the field and plant were operating at forecast rates.

Royalties are complex and related to the product sold at the wellhead. A royalty of 15% was used (in the following example) to be paid to the owner or agency responsible for the resource. Full production would be achieved by the fifth year. 27.6 mils per KWh sold will be the price for the energy for the life of the project in the base case. Costs are not escalated.

In the first year one producing well will be drilled and tested, four wells in the second and third year, five wells in the fourth and two wells in the fifth year. An injection well will be drilled in the second year and one in the third year. A dry hole is drilled in the fourth year and another in the fifth year.

The base case assumes the steam gathering system is built by the power plant operator.

The annual gross revenue will be calculated (plant output x 24 x 365) x (operating factor x capacity factor) x price. The net revenue will be the gross revenue x (1-royalty). The taxable income equals the net revenue minus intangible investment minus operating costs minus ad valorum tax minus depreciation minus depletion calculation. The net cash flow will be the net revenue minus tangible investment minus intangible investment minus operating cost minus ad valorum tax minus federal income tax. The rate of return is equal to the discount rate that would reduce the present value profit to zero. It can be estimated as the reciprocal of the years required to pay out the investment.

If an interest rate of .08 is assumed for the negative cash balance years and .04 for positive years there is a $110,852,000 contribution to the project. The rate of return in this base case is 34%.

Adjusting the base case factors and re-calculating the cash flow will identify those portions of the project that can seriously affect its economic viability. Identification of these factors will provide the basis for deciding if the risk of development is worth the investment.

The cash flow analysis (Table V) is an example of how this analytical approach can be used to check an exploration project that has developed to the stage where the next investment increment is one involving millions of dollars. The assumptions used for the base case produced a 34% rate of return which should be acceptable if other nearby developments are supplying operating plants. Federally insured deposits (in amounts above $100,000) in national banks are receiving 18%-22% interest with minimum risk.

The margin between the risk investment compared to the liquidity of an interest bearing bank deposit is a strong factor in deciding if new developments can be expected to receive 60 to 70 mils per KWh generated. Compare this with the 120 mils fuel oil will probably cost the electricity generating utility and direct heat user in 1986. The growing mil difference in the price for geothermal energy and fossil energy will overcome transportation costs from remote areas to the center of use. Various prices for the geothermal energy can be substituted to change the base case to determine the minimum acceptable to achieve the needed R.O.R. Planning and regulatory staffs should understand the $51,120,000 investment the field developer must make for an 110 MW supply system will earn more than $1,821,600,000 before tax in just 20 years at today's certificate of deposit rate of interest with no payroll or operating problems. Such safe well paying investments will not produce a supply of energy for the area's population either.

TABLE V

SUMMARY OF ANNUAL CASH FLOW

110 MV, STEAM PRICE 27.76 MILS/KWH

($000)

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 34	CUMM
NET REVENUE	0	0	0	0	9720	19440	19440	19440	573487
TANGIBLE INVESTMENT	330	1650	1650	1650	660	0	0	0	9570
INTANGIBLE INVESTMENT	1320	6600	6600	8235	4275	0	0	0	41550
OPERATING COSTS	0	0	0	0	1372	2745	2745	2745	80963
ADVALORUM TAX	0	0	0	0	583	1166	1166	1166	34409
FEDERAL INCOME TAX	-726	-3630	-3630	-4448	708	6109	6109	6230	159034
NET CASH FLOW	-924	-4620	-4620	-5438	2122	9421	9421	9300	247961
CUMM CASH FLOW	-924	-5544	-10164	-15602	-13480	-4059	5362	247961	
MEMO -- BEFORE FEDERAL TAX CASH FLOW					2830	15530	15530	15530	406995

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WORKSHOP REPORT

NEED FOR DEMONSTRATION OF SPECIFIC TECHNOLOGIES

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At Workshop Session 7A the need for various demonstration projects was discussed. Conference attendees raised issues that they felt were preventing organizations from proceeding with geothermal development. Then, demonstration projects which would provide solutions to problems posed were listed. As a final action, attendees were asked to vote for the demonstration project which they felt had highest priority for solving problems that limit geothermal development. Each attendee was given three votes and was allowed to vote either singly for three separate projects or vote all or any combination of votes for a single project or a combination of several projects.

The list of demonstration projects and associated prioritization by voting follows:

No. of Votes	Demonstration Project
16	Downhole Pumps-Performance, Reliability
15½	Wellhead Conversion Devices-Second Generation
14	Crystallization and Brine Handling
14	Cooling Water-Availability, Chemistry
11	Continue Demo Support
4	Heat Exchange-Performance, NCG Remove
4	Hybrid Units-Study Economics
1	Instrumentation, Data Acquisition, Authorization
½	Two-Phase Flow Prediction