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ABSTRACT

These proceedings are a compilation of papers presented at the Second Geothermal Conference and Workshop. The papers report the results of EPRI-sponsored geothermal research projects and research and development projects sponsored by electric utilities and resource companies. The papers also present the views of various representatives of industry, government, the public, and financial institutions on risks associated with geothermal development and how these risks might be shared.

The objectives of the conference were to report the results of EPRI-sponsored research to the geothermal community, to exchange information on the different approaches reflected in current commitments or plans to construct geothermal power plants, and to conduct a workshop on resource and development risk. A further objective was to investigate the need for some form of private or government-sponsored reservoir insurance.

In general, these proceedings update information on geothermal research and development projects that were active during 1978. Regarding the question of reservoir insurance, the consensus of the speakers at the conference was that it is probably not needed at this time.

TABLE OF CONTENTS

SESSION VI - RISK OF GEOTHERMAL DEVELOPMENT

WELCOME ADDRESS

Harold Bell
Arizona Public Service Company
Chairman, EPRI Geothermal Program Committee

Having the correct perspective is an important part of getting the job done. As both individuals and utilities, we have to make sure that both today's and tomorrow's problems are put into perspective so that appropriate solutions can be effectively developed. It's only when we have this attitude that we can continue to provide reliable, easily-produced, low-cost electric energy to our customers. Indeed this is our reason for being in business--to supply energy profitably. Correct perspective is very important, but sometimes difficult to achieve with geothermal. One could liken this to the "carrot and the horse" situation. We hear promises of the potential for geothermal but we have severe difficulties in getting it on-line. One reason for this pessimistic viewpoint is because although some progress is being made, it still is far too slow. One example of this is the geothermal demonstration plant. Industry, EPRI, and DOE all want this project to move ahead and be successful. Another example is geopressure with its vast potential of gas and heat energy. Certainly the challenge that faces us here today is how to cut the string so the carrot will be in the feed bucket.

Fortunately, however, some things do move at a better pace. Indeed, during these sessions we will look at some of the progress that has been made since our workshop last year in Warm Springs, Oregon. Within this last year program emphasis has changed, some directions have changed, even the attitudes of utilities and government have changed. We have seen an interesting combination of becoming more patient and yet more impatient. Although this past year has given us some answers, there are still many basic questions that are still unanswered. For instance, we are still asking the questions where can we find geothermal, what is the true extend of the resource, and how much of it can we successfully use to supply our customers' needs?

As we go over these projects again and critically evaluate the progress that has been made, we encourage you to comment upon them so we can get your inputs as to their appropriateness. Indeed, do we have the correct perspective and are we getting the results that we should get? We basically are asking for your help in evaluating what we are doing and what direction we are going. We certainly are not naive enough to think that we know it all, so consequently we are asking for your assistance in making sure that we have the best thinking applied to the work that is being done.

In these 3-1/2 days we will go over the current EPRI projects and utility new plant commitments. Risk is always an important factor for the utility company. Indeed, trying to minimize this is important to make sure that our costs are kept low. The one day that we will spend on risk of geothermal development should be very worthwhile and provide some of the background thinking that is necessary for proper evaluation of any geothermal potential.

Again, in all of our considerations I would like you to keep geothermal in proper perspective. It is both a close-in and yet a future resource. Close-in from the standpoint of the present capacity of The Geysers and the soon capacity of Imperial Valley. Yet as we look throughout the West and even now to the Gulf Coast and East, we find we know very little about this resource. The true extent of geopressure, magma or hot dry rocks, is not understood at all.

The interface of geothermal technology with other emerging technologies such as solar or low quality heat sources is important. In fact, some of the work being done in the geothermal area will definitely benefit these other areas. So in many respects, geothermal is in the "goldfish bowl" situation. A lot of work is being done, a lot of people are watching this work, and in the end a lot of this technology will be used in other areas.

Let's make sure this work is right and useful. So give us the best of your listening and your thinking.

ENERGY IN THE YEAR 2000

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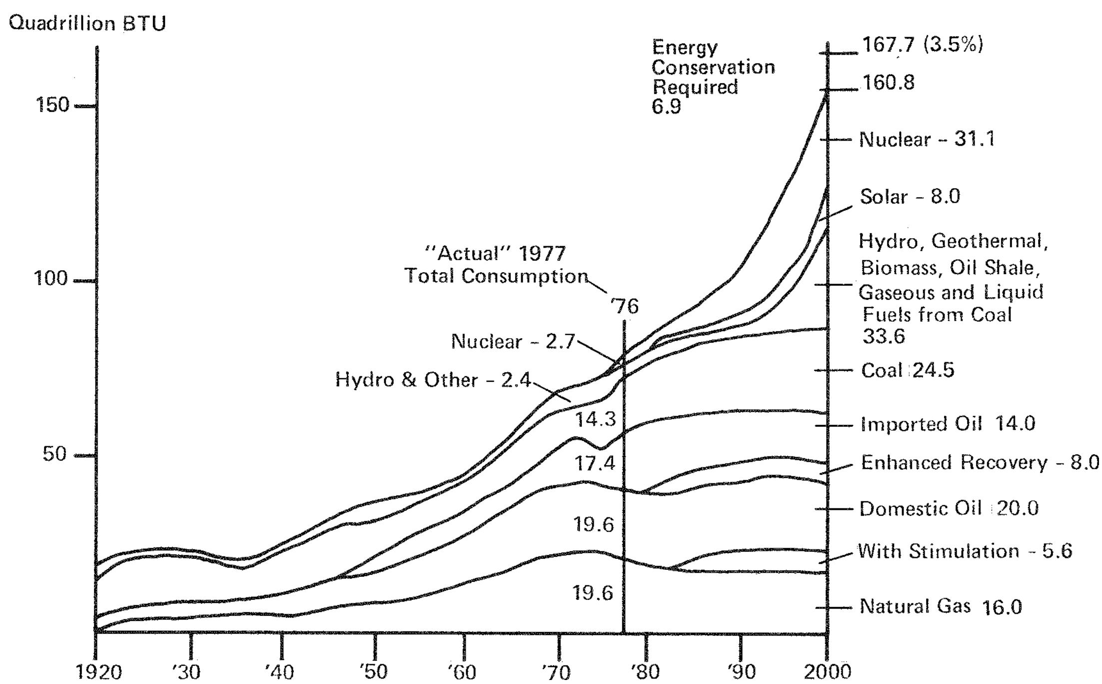
For the rest of our lives and beyond, energy is going to be a subject of primary interest to all of us. Most of my life has already been spent concerning either fuels acquisition, development of the electric and gas facilities or finance.

In order to see how geothermal energy may fit into our future, I propose to discuss energy in the year 2000. That year seems to be a critical point in time as far as the development of energy resources is concerned. Historically, about fifty-five or sixty years have been required to make the transition from reliance on one type of fuel to another. We moved from wood to coal to petroleum products, each in about fifty-five years. The use of coal peaked in 1918. After the oil binge of the Forties and Fifties, it was 1975 before we equalled the high point in the use of coal that we reached in 1918.

A look back into history shows how we used our fuels and gives us some insight as to how they may be needed in the future. We neglected the development of our coal resource from 1945 to 1975 because of cheap oil and gas. As far back as the mid-1930's, oil has dominated our energy picture, displacing coal, because oil was clean, available, useful, convenient, and cheap. Prior to the 1920's, we were using mostly coal--in transportation, heating (we had no air conditioning), and industry; we depended almost entirely on coal.

In the early years when gas was a byproduct of oil, we used a small amount of gas in industry but wasted most of it by flaring it in the field just to get the oil up out of the ground and not until the Forties did we begin to use the gas sensibly and put it to all of the high value uses of today. As you can see by the chart, the domestic and imported oil would

ENERGY CONSUMPTION AND PRODUCTION
(Actual and Projected)



begin to pinch out our coal development and continue until 1973. We all remember the Arab oil crisis--suddenly we began to take stock of where we were.

As we move into the future, I want to make a very important point. That is, that all the new emerging energy sources, other than coal, oil, and gas, amount to so very, very little today, but <u>in the future they are to be our total salvation</u>.

We think of all the vast hydro resources we have, yet they only meet two or three percent of our needs. Nuclear, after twenty-odd years of commercial development, serves only three percent also. All the other new sources, such as solar, geothermal, oil shale, and coal gas and liquids, are not yet on the map. When you consider the amounts in total as compared to our total fuel comsumption, they are almost insignificant. I point this out because if we are to get from 1978 to the year 2000 without serious economic and social damage, we must develop huge amounts of energy from resources that we know very little about in an extraordinarily short time.

Projecting the amount of oil and natural gas available to the year 2000 indicates a steady decline in normal domestic production. We can expect to obtain an additional amount from new stimulation techniques, which may (if economic numbers are right) delay the decline in total domestic oil supply to later years. We already are using secondary measures to recover gas and oil, but only recover about thirty to thirty-five percent of the oil in the ground. With gas, the percent varies. We expect to get more if we are successful in developing more effluent methods of recovery. If we cannot get the oil out of the ground, perhaps the energy can be used by either burning or heating it in place to produce it in a gaseous state. Some way to get the other two-thirds out of the ground could enhance our domestic fuel supply immeasurably.

Now, to imported oil. There is a large amount of oil in the world, more unproven than there is proven. The United States, of course, uses much more of its resources than any other country. Some of the future oil supply shown on the chart is speculation, some of it is proven exploration. Regardless of the exact number, the stark fact is the United States is in short supply of petroleum today. We are not going to have enough to meet our needs and have not had for some time. Imported oil is now about forty-five percent of our total petroleum supply. Countries like South America and Mexico are projected to have much more petroleum products than the United States ever had. All of the underdeveloped countries still have most of their oil left. Each of the industrialized countries (Germany, Japan, and the United States, principally) do not have sufficient petroleum products to carry their present economy.

Continuing to rely on imported oil for about half of the future petroleum supply is a vulnerable position for this country. Our transportation system and defense system depend almost entirely on oil. It is impossible to convert to new developing fuel sources in a short period of time. We will require a huge increase in coal development in the next twenty-five years. That is a very difficult job we have not been able to start. The Government talks but does not act. We have no federal policies which will permit industry to move ahead in <u>any</u> fuel,much less provide incentives to accelerate exploration, construction, etc.

Leaving the supply side of the problem for a moment, I would like to explore with you the magnitude of the energy demand by the year 2000. This will allow us to estimate the size of the "energy gap" that new emerging resources must fill.

Almost all the serious projections indicate that to maintain our economic and industrial energy base, we will grow in energy use from about 80 quads in 1978 to about 169 quads in 2000. That represents about a three percent annual growth. The amount of conservation thus far acceptable to the public will bring that down to about 160 quads.

You probably want to stop me now and argue that we cannot afford to continue the energy binge and use that amount of resources. If you will bear with me as I explore what will be required to reach that level, I think we will all agree there is little likelihood of it happening.

As we examine the energy consumed from each source in the 1977-78 period, it becomes very clear how serious our dependence on foreign oil has become. It is vital that a sound energy plan address the fact that we can lose the option of imported oil--all or in part. We must be able to live and function without it.

Starting from the top of the chart--domestic oil is now expected to about hold the present level of about 20 quads production through 2000, an optimistic view given the present regulatory climate.

Imported oil is expected to decline slightly over a period from 18 quads at present to some 14 quads in 2000. I think this is reasonable to assume even though the pressure will be on to increase imports. Developing nations which have the oil will need more themselves and we have been told by these countries that the exports will be stabilized, and in later years reduced.

Natural gas--there is very little argument that our natural gas supply will continue to decline from about 20 quads to 16. Alaskan gas will help to delay the inevitable, but it will not reverse the downward trend. I had included Algerian LNG and Mexican gas, but years of delay and indecision by President Carter's administration made the Mexicans and Algerians mad, so the Mexicans are now going to sell us their higher priced oil and use the gas themselves, and Algeria will sell the gas to someone else.

Coal we have in large quantity. We are consuming about 15 quads of coal energy now and the demand for coal in these next twenty years will be enormous. My figures show that it will almost double. Common sense and simple arithmetic tell us we must at least double the supply for direct uses and if we are to make gas and liquid fuel from coal, the demand will triple. The President says we must and will do it. Everyone except perhaps environmentalists agree--but are we going to? I am not optimistic and here is why: The largest long range reserves of low sulphur coal are in the West on federal ground. Since 1971, we have had a moratorium on leasing of federal coal land and have yet to invoke rules that will encourage development by industry.

Environmental regulations and reclamation costs and rules have prohibited development in many prime areas. We do not have the trained manpower to work the new mines. It requires two to three years to train a miner, six years to bring a new mine up to production. The machinery to open new mines is not available and the manufacturing plants to build the machinery are not built. Railroads are inadequate to handle the transport of coal.

Next is nuclear power. Nuclear energy is the cheapest. It can provide an unlimited future fuel supply with no air pollution, immaculate safety records, and it is the only real hope to meet our energy goals. Regulatory delays and opposition by the anti-nuclear organizations have frustrated greater development, but there is some progress.

Two recent Supreme Court decisions lifted some of the clouds from nuclear power plant construction, and there is hope. A massive effort is necessary, however, to bring nuclear power up to the projected need of about 25 quads by the year 2000, some ten times what it was in 1977. Only immediate and full cooperation of the Federal Government and the public will allow this to happen.

With hydroelectric rounding out a total of 102 quads from known resources, this leaves a deficit of about 60 quads if we have all the imported oil we need, or about 80 quads if we do not. To put it another way--by the year 2000, we must develop from new and emerging energy sources an amount equal to the total energy used in 1978.

With present methods, we now recover only about one-third of the oil from underground sources. It is estimated that with a maximum effort and incentives as far as price is concerned, oil recovery can be increased through more expensive, more sophisticated recovery methods. The estimate is that some 8 quads per year can be produced by the year 2000 through these methods.

Similarly, with natural gas, more advanced methods may produce some 5 to 6 quads in this time frame.

Next is solar energy. I think we can all acknowledge that there is a vast amount of solar energy available on the earth's surface. The problem of conversion to a useful form sounds simple, but is, in fact, quite difficult. In the test of areas, such as Arizona and the Pacific Southwest, where solar is available in sufficient strength for six to eight hours in an average day, this means that in the remaining sixteen to eighteen hours, other fuels must be used or some storage is required. Therefore, for one hundred percent reliability, one must build two or three times the capacity needed to serve a given load just to provide energy for storage and also must develop some form of storage that will be reliable and economical for the consumer. This presents a formidable handicap for solar energy to compete with other fuel sources. To assign an 8 quad goal to solar energy by the year 2000, in my opinion, is overly optimistic and one of the most important facts generally overlooked by advocates of one fuel over another, is that very few fuels are applicable to all of the various uses in our society. For example, transportation, which consumes about one-third of our total energy, depends upon liquid and gaseous fuels because they are transportable and flexible in their use. Since solar energy is so diffused, it does not lend itself to transportation needs. Therefore, one-third of the market is out of reach for solar. Industrial uses generally require large concentrations of energy and, again, solar is very difficult and expensive to apply. This narrows the field to the remaining one-third, which is residential and small commercial uses. Since retrofitting is largely out of question because of physical limitations and cost, we are then dealing with only the growth in residential and commercial, thus narrowing the total market to some fifteen to seventeen percent. If one-half of all new installations in the next twenty years could be developed by using solar (an impossible goal, I submit--where would you put the solar panels to serve a high rise apartment building in downtown New York or Phoenix for that matter?), you would be dealing with about seven to eight percent. The 8 quads is five percent of the projected total need, still a very ambitious goal.

Without considering these logical limitations, a Department of Energy official recently predicted that some twenty-five to fifty percent of our total energy by the year 2000 could come from solar. This is totally ridiculous and tends to mislead the public into believing that we do not have to make an all-out effort to develop coal, nuclear, and petroleum resources. The impression is left that solar and other exotic fuels are going to save the country from an energy disaster. If we can develop solar energy in the next twenty years to produce 1 or 2 quads of energy per year, we will have performed a miraculous technical breakthrough and will have made a significant contribution to our future energy needs.

Biomass, or the conversion of biological materials to useful fuels, is credited with some 6.3 quads in the year 2000 and, again, this is more than two times our present production from nuclear power. Keep in mind that at the present time, there is not one single successfully operating commercial size biomass converter in this country. So, a goal of 6 quads, which is about one-third of our domestic oil supply or our natural gas supply and almost one-half of our current coal use, is a highly optimistic goal.

Nuclear breeders are credited with 3 quads by the year 2000 and nuclear high temperature gas reactors an equivalent amount. These are attainable goals based on technical and engineering knowledge, but given the present philosophy of the administration in Washington, the nuclear breeder may be a long way down the road. The high temperature gas reactor is, in my opinion, the most promising of all the energy options. It will be more economical in the use of fuel than the light water reactors being installed today. It is environmentally more acceptable since it resolves the problem of proliferation of fissionable products for making bombs--it burns the product rather than leaving it as a product to be stored. It can be adapted to operate as a breeder which produces more fuel than it burns. The Carter administration seems to be in favor of further development of the high temperature gas reactor which, to the utilities, is very encouraging.

Oil shale is a known resource and a known technology, and it has an economic disadvantage that should disappear as oil becomes more expensive. It will require very substantial capital investment and some additional research, but we should be able to meet these goals if a sufficient effort is made to develop the product. It is simply a matter of making the commitment today.

A large potential resource is gaseous liquid from coal. Almost totally overlooked in projecting the huge amount of fuel from this resource is the fact that most of the coal will have to be mined to produce this fuel. When you add that amount of coal to the above commitment to double the directed use of coal for other processes, it places an unreasonable burden on coal. Since we have taken few, if any, positive steps to encourage the construction of coal gasification plants and are still in the research stage, I find little room to be optimistic as far as this projection is concerned. You will note that 14 quads by the year 2000 is equivalent to the coal used in 1977. If we add the coal needed to meet the coal gas and coal liquid objectives to the normal uses of coal and arrive at about 38 quads of energy, this will require some ten three-million-tons-a-year mines to be added in the next twenty-two years. If we accept the fact that it takes six to seven years to bring a three-million-tons-a-year mine to production and we are still debating the question of federal leasing of coal lands in Washington, I suggest that we are not going to make the goals we have set for coal in the near term future.

Finally, and the reason we are all here today, there is the vast heat source in the earth's crust called geothermal. The amount of useful geothermal energy is unknown but it is undergoing some accelerated research.

We have not been able to discover through exploration additional easy-to-develop sources such as The Geysers in California. There is no doubt about the quantity of heat in the earth's core, but it is a highly technical, very difficult problem to extract and convert the heat to a useful form. The estimate of 3 quads from this source in the next twenty years is highly optimistic. Keep in mind, that amount of energy is about equal to the 1978 production from nuclear sources after more than twenty years of development.

Right now, geothermal is one of the good guys. It does not have the political problem that some of the other options such as nuclear or coal have. We do have the technical problems ahead of us, but I am sure they will be solved. The other thing we have not done is convince our own management that geothermal is here. We have not the commitment to geothermal to bring it to commercial status. There are reported to be ten plants now either planned or being readied for construction and that is encouraging. What is not encouraging is that there is a pressing need for new economical resources and these small efforts are only a tentative step. What we really need are some bold steps. We, you and I, must convince the Federal Government, the system planners, the financial people, and the management of our companies that a geothermal plant should be in our long range planning. First, however, we must be convinced ourselves that it deserves the rather large commitment required. Until we in the industry are convinced that it is a viable, economical option, I doubt you are going to get anybody to invest the huge amounts of money needed for a realistic geothermal exploration and development program.

If you get the feeling that I am pessimistic about the energy future of the country, you are correct. When I try to reconcile the present level of effort in any of the areas that I have just described, I conclude that it will take the total commitment of the Federal Government and the public at large to allow development of any one of the new emerging resources to the level required by our projected needs. If we falter in the pursuit of any one of the ten or more new sources, the burden will fall heavier on the known resources such as coal, oil and nuclear. A maximum effort is required for development of each; therefore, it casts serious doubt on whether there is sufficient time to change directions and increase the output from known sources.

We speak of energy options, but I do not see them as either/or type options. Ten years ago, we may have had options, but time has run out. Debate must end and industry must be encouraged to rapidly move ahead.

The real question is whether the Government will allow industry to move ahead while there is still time, and precious little time, to accomplish the difficult job ahead.

There is the dimension of the energy problem. As I said in the beginning, I do not offer any pat solutions. The urgent need for solutions requires that we not ignore any option, but sooner, not later, must pick a winner, or a few winners, and run with them. We will dissipate our precious time and resources pursuing everything at once. We must quit talking, concentrate our efforts and bring some energy plants on line.

EPRI GEOTHERMAL PROGRAM - OVERVIEW

Vasel Roberts

Introduction The United States will need about 9×10^{12} KWhr of electric power in the year 2010. A shortfall of from 2 to 37 percent is expected at that time, based on best estimates of the availability of the various energy resources. The mere fact that the most optimistic estimate shows a 2 percent shortfall is in itself sufficient to demonstrate the need for placing high priority on the development of alternative energy sources to help make up the shortfall. As can best be forecast at this time, geothermal energy will contribute up to 2% of the nation's needs by the year 2010. It should be recognized that although a role for geothermal energy is assured, the pattern of development and usage is not yet clear. Much will depend on steps taken by industry and the government to enhance the rate of development.

Forecasting the growth of geothermal generating capacity is an uncertain art and many widely varying estimates have been made from time to time within industry and government. Since the utilities represent a major market for geothermal energy, a view of geothermal utilization from their perspective is very useful, particularly in terms of identifying trends. EPRI has conducted two small surveys among those utilities that are most likely to have geothermal prospects in the near and intermediate term. One survey was conducted in the Spring of 1977 and the second in the Spring of 1978. It was not so much the objective to determine firm commitments to geothermal power plants, as to sample the mood of the industry. With this in mind, the respondees were asked to give their best estimates of actual power on line, announced plans, probable capacity and possible capacity at 5-year intervals to the year 2000. Table 1 shows the result of the 1978 survey. Since the most optimistic projections do not even approach the growth in expected power demand, it may be assumed that the resource is viewed as the limiting growth factor, not demand.

Comparison of the 1977 and 1978 surveys shows a marked increase in the estimated capacity beyond 1985. Figure 1 shows the difference in the estimates of probable capacity for the two surveys. The estimate for the year 2000 almost doubled in the one year interval. This is construed as an increased level of interest and confidence, based primarily on developments during the year that brought about expectations that at least two power plant types (binary and direct flash) and two resource types (moderate and high temperature) would be demonstrated early in the 1980's. EPRI's plans to support a moderate temperature binary cycle demonstration plant, DOE's announced intent to fund a geothermal demonstration plant and other industry activities, as shown in Table 2, provided the basis for the new expectations. It may be concluded from the number of commercial size direct flash projects in Table 2, in comparison to the number of binary projects, that industry views the direct flash technology as being much more mature than the binary technology.

Program Objectives The main objective of EPRI's Geothermal Program is to accelerate geothermal development. This is closely followed by a secondary objective to assess the role and importance of geothermal energy in helping to meet future energy needs. In support of the main objective, more specific objectives are to: 1) sponsor R&D efforts that will adapt current technology to meet the needs of geothermal development, and 2) develop new technology for geothermal development as required to match the different geothermal resource types as they are discovered and proven. The near term emphasis is on the development of water dominated hydrothermal resources, with particular emphasis on moderate temperature low salinity resources.

Program Structure The Geothermal Program is subdivided into three subprogram areas: Near Term Hydrothermal, Geopressure and Advanced Technology, as shown in Figure 2. The major project in the Near Term Hydrothermal subprogram is the low salinity moderate temperature hydrothermal demonstration plant. This work is being done in cooperation with the San Diego Gas and Electric Company and a number of other participants. The demonstration plant project was started in 1976 with a feasibility analysis and conceptual design study. This led to an engineering design for the Heber Binary Cycle Plant in 1977. To date, all of the optimization studies have been completed and detailing of the design is about to start.

The supporting technology projects consist of work in the following areas:

- Environmental baseline data acquisition
- Heat exchanger performance and scaling tests
- Axial flow and radial in-flow organic turbine preliminary design studies and fluid properties measurements

- o Binary loop test

- o Study of waste heat rejection options

The geopressure subprogram was recently initiated. The first project in this area will be an assessment of the requirements for commercialization. A contractor will be selected from competing proposals, and this first project started during the second half of this year. It is anticipated that the funding in the geopressure subprogram will increase next year.

The Advanced Technology subprogram includes significant efforts in the following areas

- o. Development of a capability for computer simulation of the equilibrium chemistry, chemical kinetics and scaling kinetics in geothermal brines.

- o. Design of a mobile geothermal fluids test laboratory.

- o. Design of the turbine section and test of a rotary separator/turbine.

- o. Support to two projects in hydrogen sulfide control, both in cooperation with the Pacific Gas and Electric Company.

Program Budget

Table 3 shows the 5 year budget plan for EPRI's geothermal program. Most of the projects are already in place for 1979, but some new project starts are anticipated in 1980.

TABLE 1

SURVEY OF ELECTRIC UTILITY FORECASTS - GEOTHERMAL POWER CAPACITY

	MWe				
	1977	1985	1990	1995	2000
ACTUAL	502				
ADVANCED		2,019	3,019	3,619	3,919
PROBABLE		2,664	5,414	7,473	9,023
POSSIBLE		3,374	7,664	11,323	14,723

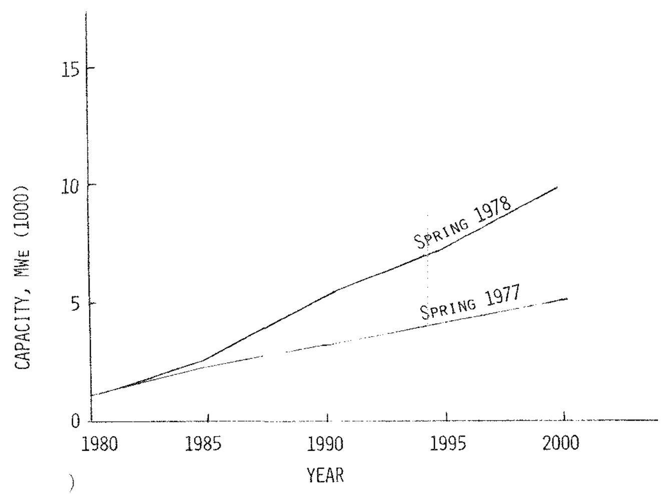


FIG. 1 ESTIMATED PROBABLE GEOTHERMAL CAPACITY - UTILITY SURVEY

TABLE 2

INDUSTRY ACTIVITY

Site	Approx. Resource Temp.	Plant Type*	Proposed Capacity	Partners	Proposed Funding Source	Status
East Mesa, CA	360°F	F/S	50 MWe	Republic	DOE Loan Guar.	Depends on resource confirmation
Heber, CA	360°F	F/S	50 MWe	SCE/Chevron	Private	Agreement of intent
Niland, CA	500+°F	F/S	10 MWt	SDG&E/DOE	Private + DOE	Hypersaline experimental facility
No. Brawley, CA	500+°F	F/S	10 MWe	SCE/Union	Private	Depends on developing ways to handle high salinity brines
Puna, Hawaii	600+°F	F/S	3 MWe	Hawaii/DOE	DOE	Proceeding
Roosevelt Hot Springs, UT	500+°F	F/S	50 MWe	Rogers/ Phillips	DOE Loan Guar.	Uncertain
Valles Caldera, NM	500+°F	F/S	50 MWe	PSNM/Union	Private + DOE	Agreement of intent
East Mesa, CA	370°F	B	10 MWe	Magma	Private	Under construction
Heber, CA	360°F	B	50 MWe	SDG&E et al	SDG&E/EPRI/ DOE	Design underway & agreement of intent
Raft River, ID	290°F	B	5 MWe	DOE	DOE	In procurement phase

* F/S = Flashed steam; B = Binary

SCE = Southern California Edison
SDG&E = San Diego Gas & Electric
PSNM = Public Service Company of New Mexico

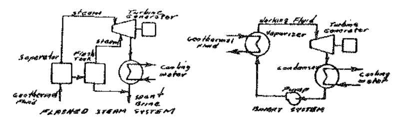


FIGURE 2

GEOTHERMAL PROGRAM STRUCTURE

PROGRAM	SUBPROGRAM	PROJECT GROUPS
GEOTHERMAL	NEAR TERM HYDROTHERMAL	50 MWe DEMONSTRATION PLANT
		SUPPORTING TECHNOLOGY
	GEOPRESSURE	REQUIREMENTS DEFINITION
	ADVANCED TECHNOLOGY	ADVANCED HYDROTHERMAL
		ADVANCED GEOTHERMAL

TABLE 3

GEOTHERMAL BUDGET

	$000					
	1978	1979	1980	1981	1982	TOTAL
HYDROTHERMAL	1,620	1,500	1,150	700	500	5,470
GEOPRESSURE	300	500	700	800	1,200	3,500
ADVANCED TECH.	580	500	850	1,300	1,500	4,730
	2,500	2,500	2,700	2,800	3,200	13,700

HEBER GEOTHERMAL DEMONSTRATION PLANT

EPRI RESEARCH PROJECT #580-2

C. R. Swanson - San Diego Gas & Electric Company, (CA)
J. W. Carroll - San Diego Gas & Electric Company
J. L. Lewis - Fluor Engineers and Constructors, Inc.

Recognizing the desirability of demonstrating on a commercial scale the operation of the binary cycle process for electricity production from geothermal resources, San Diego Gas & Electric Company (SDG&E) and the Electric Power Research Institute (EPRI) formed a consortium of participant utilities and resource companies to initiate the Heber Demonstration Project and propose it to the Department of Energy (DOE) for cost-sharing support within its geothermal demonstration program. Under the joint funding of the consortium members, with EPRI as the major contributor, the project has progressed through the preliminary engineering and permitting phases, having received all the major regulatory approvals necessary for construction. While detailed engineering will be undertaken in the immediate future, equipment procurement will not be initiated until a commitment for the needed funding is received.

The concept of a commercial-scale binary cycle demonstration plant operating on liquid-dominated geothermal resources was evaluated and recommended by the Ben Holt Company as a result of its well-known feasibility study for a geothermal demonstration plant conducted for EPRI during 1975 and 1976. After surveying the status of numerous geothermal sites in the western U.S., the Holt study concluded that the Heber site appears to have the best qualifications for a successful demonstration project in the early 1980's. The reservoir temperature of 360°F bottomhole is close to the average of the identified resources in the western states. Their survey indicated that the composition at Heber is the most representative of other hydrothermal resources in the United States. The salinity of the Heber brines, approximately 14,000 ppm, is slightly higher than average. However, the heat exchanger test conducted by SDG&E in 1974, and reconfirmed by a later EPRI test, indicated there should be no great difficulty in using these fluids. The study concluded that any system which could handle the Heber fluids should at least be capable of handling fluids of lower salinity. Further, the Holt study found that the binary energy conversion process has the potential for technical, economic and environmental feasibility in producing electrical energy from a liquid-dominated reservoir. The binary cycle may be capable of utilizing approximately 30% less geothermal fluid per net kilowatt generated than the flash cycle and therefore may be more economic for this temperature reservoir and those with lower temperatures. It may also be more environmentally acceptable. Last, the Holt study concluded that the binary plant at Heber has the potential to produce electric energy at a cost competitive with conventional economic power generating sources.

The binary cycle has never been demonstrated on a commercial scale. Since commercial-sized turbines required for binary cycle plants have never been constructed, the technological risks associated with this developmental equipment must be demonstrated to be minimal before utilities can employ this energy conversion option for commercial application. The Heber Project is a logical extension of the small-scale binary cycle testing plants now underway at Raft River, Idaho and East Mesa in the Imperial Valley.

The principal objective of the Heber Demonstration Project is to design, construct and operate a commercial-scale binary cycle geothermal power plant in order to establish the technical and economic feasibility of producing electricity from the low salinity, moderate temperature resource at Heber. The results of this demonstration will be documented and disseminated to industry. Information resulting from this project will be applicable to a wide range of geothermal reservoirs in the U.S.

Participants in the Heber Project include a broad segment of industry. The project is being managed by SDG&E, the principal owner (77%). The other plant owners include Imperial Irrigation District (10%), Los Angeles Department of Water and Power (10%) and Southern California Edison Company (3%). As mentioned earlier, EPRI is the major contributor ($4.6 million). Other contributors to the project include:

- Nevada Power Company
- Portland General Electric
- Republic Geothermal, Inc.
- Geothermal Resources International, Inc.
- California Department of Water Resources
- California Energy Commission

All Participation Agreements have been executed and are now in effect. On June 20, 1977, the project team submitted a response to DOE's Request For Expression Of Interest for undertaking a demonstration plant. It also submitted an extensive proposal to DOE on January 31, 1978 in response to a Program Opportunity Notice for a geothermal demonstration plant which was issued on October 1, 1977. DOE is currently re-evaluating industry's need for its geothermal demonstration program and has stated intentions to report on its findings by the end of June. Funds for cost-sharing in a demonstration plant project are a part of the approved DOE budget for FY 1978.

As project manager, SDG&E has responsibility for the design, construction and operation of the plant. The reservoir will be developed by Chevron Resources Company and New Albion Resources Company, a subsidiary of SDG&E. Chevron will be the field operator. Negotiations between SDG&E and Chevron for the purchase and sale of a geothermal heat supply to the plant are nearing completion.

Imperial Irrigation District has agreed to provide fresh Colorado River water to the plant for cooling purposes during the early years of plant operation through the utilization of its existing canal system. Due to limitations imposed by local regulations, a fresh water supply will not be available for the plant's entire operating life. Therefore, an alternate means of cooling, such as the use of irrigation drain water, will need to be employed.

Imperial Irrigation District has also agreed to purchase the power produced by the plant. IID will construct the necessary power transmission lines to tie the plant into IID's existing power distribution system. The plant will be a baseload facility meaning it will essentially be on-line 100% of the time that it is operable or not undergoing routine maintenance procedures. It is anticipated that the power sales agreement with IID will be executed shortly.

SDG&E's Project Manager for the Heber project, Mr. Mike Carroll, will now discuss the status of the project and its progress during this year.

The Heber Geothermal Demonstration Plant will utilize moderate temperature, low salinity geothermal brine produced by Chevron Resources Company from the Heber reservoir located at the southern end of Imperial County, California. The Heber Project will be the first U. S. commercial-scale geothermal power plant utilizing liquid-dominated resources. The binary energy conversion process to be employed in this plant is an advanced concept that has the major advantage of being capable of converting a greater amount of geothermal heat into electrical energy than other processes. In the binary cycle, hot brine will be pumped from the wells and its heat will be converted into electrical energy by means of a heat exchanger/secondary working fluid/turbine-generator system. The cooled brine will be injected into the reservoir. The proposed working fluid (an 80/20 mixture of isobutane and isopentane) will be preheated and vaporized by heat exchange with the brine to a temperature of 300^{o}F at a pressure of 500 psia. The vapor would expand through the turbine and exhaust to the condensers and accumulators and then be pumped back through the brine heat exchangers, completing the cycle. Much of the technology is now in existence; however, it has not been proven on a large scale. The major plant component, the hydrocarbon turbine, has never been constructed in the 65 MWe size

An artist's rendering of the plant depicts the completed plant. The major plant components include the cooling towers, turbine-generator and electrical equipment, brine/working fluid heat exchangers, working fluid condensers, accumulators and condensate pumps. The Chevron production well island is also shown.

The project will be conducted in six separate phases. Phase I is the feasibility study mentioned earlier. Phase II includes the preliminary engineering design and permitting process. Work on this phase is currently underway. Phase III will involve the detailed engineering design, equipment procurement and site preparation. Construction will be accomplished during Phase IV. Phase V will include plant start-up and the initial test period. Phase VI will include long-term operation and performance evaluation.

In the licensing area, the Environmental Impact Report, a Rezoning Application and the Conditional Use Permit were initiated in May, 1977. These documents were initially approved after twelve months of review by the Imperial County Planning Commission. The Imperial County Board of Supervisors granted final approval last month to all three documents. No major issues surfaced during the review and approval process; however, a special problem was addressed. Imperial County wanted to impose a $250 per net-megawatt fee on both the plant operator and the resource developer to cover costs incurred by the county as a result of any problems created by the plant's operation. The final order was amended to read that (1) SDG&E and Chevron will cover any and all excess costs as determined by actual plant experience and (2) the Imperial County Board of Supervisors can levee a fee only after a public hearing process.

The federal environmental impact studies will commence when the project is selected by DOE for cost sharing. The Air Pollution Control District and Regional Water Quality Control Board permit preparation processes were initiated earlier this month. The Building Permit applications will be prepared after the requisite detailed engineering has been accomplished.

The total capital cost comprised of the first five work breakdown phases described previously is estimated to be $49.5 million (escalation included). The basis for this capital cost estimate is the EPRI feasibility study, Fluor's preliminary engineering studies and SDG&E's financial assumptions.

Fluor is the engineer/constructor selected to design and build the demonstration plant. Fluor has the primary responsibility for the overall project design; however, they have subcontracted the brine and hydrocarbon work packages to the Ben Holt Company. Mr. Jerry Lewis of Fluor will now describe in more detail the work accomplished to-date on the engineering design of the plant.

This portion of the presentation summarizes the technical progress achieved in the development of the Heber Geothermal Power Plant Design, starting with a review of the baseline provided by EPRI and continuing through subsequent design development including the trade-off studies and design optimization, and a summary of an on-going study of the use of two half-capacity turbines.

The baseline for the project consisted of the feasibility study and continuing design studies performed for EPRI by Holt/Procon. One of Fluor's initial tasks on the Heber project was to review the baseline studies. This effort was initiated in August, 1977, and concluded in November, 1977. The major conclusions of Fluor's work are: (1) In general, the thermodynamic base design is valid, and (2) the process system design as represented on the Holt/Procon Process and Instrument Diagram (P&ID) is a valid baseline. Further study is needed, however, to develop this design, particularly in the area of process control systems design.

Selection of Thermodynamic Conversion Cycle
During Fluor's review of the baseline design, new developments affecting the decision to use the binary cycle conversion system for the Heber plant design were identified as follows:

1. The EPRI study baseline cost estimate is significantly different from current estimates in the area of geothermal energy (resource) cost. The baseline resource cost data was derived independently, without the benefit of contract negotiations with Chevron. Therefore, a reevaluation based on current energy supply cost negotiations between Chevron and SDG&E was deemed necessary.

2. Analysis of baseline cycle efficiency estimates resulted in a lower estimate of plant efficiency, and provided further reason for reconfirming the binary cycle selection.

Direct Flash Versus Binary Cycle Study The purpose of this study was to: (1) Reevaluate the thermodynamic baselines and plant performance, comparing the binary cycle and the direct flash cycle; (2) use current resource energy costs and refined design criteria, including revised estimates of mechanical and electrical efficiencies; and, (3) evaluate both systems for a power plant net capacity of 45 MWe.

Five energy conversion cycle cases were studied as follows:

Binary Cycle

Case I - Pumped wells with 150°F brine return temperature.

Case II - Free-flowing wells with 150°F brine return temperature.

Case III - Free-flowing wells with 200°F brine return temperature.

Direct Flash Steam Cycle

Case IV - Based on GE Turbine, with free-flowing wells and 200°F brine return temperature.

Case V - Based on Elliott Turbine, with free-flowing wells and 200°F brine return temperature.

The conclusion of this reevaluation was a confirmation that the binary cycle, Case III, produced a lower net power cost over the life of the plant than either of the direct flash cycle cases (Case IV and V).

Optimization Studies

The results of the above-described work provided the basis for idntifying special process and equipment optimization work necessary to support the execution of detailed process design development. The major areas of optimimization involved:

Turbine Piping Geometry
Hydrocarbon Circulating Pumps
Working Fluid Selection
Brine Supply System
Cooling System

Turbine Piping Geometry

Purpose - The purpose of this study was to develop alternative turbine exhause piping configurations, and to establish optimum turbine/HC condenser equipment orientation so as to minimize the pressure drop effect on cycle performance. The study was also to assess the impact of axial and radial flow turbine geometry.

Results and Conclusions - Six alternative piping design cases were identified. From the results of this study, it was concluded that:

(1) Piping and layout problems are about the same regardless of the type of turbine employed, and the differential cost impact is minimal.

(2) In order to maintain exhaust flow symmetry (thrust balance) two or four condenser shells are required for the axial turbine.

(3) The plot plan layout prepared for the DOE Proposal will accommodate any of the case studies.

(5) There is no economic incentive for using expansion joints in the exhaust piping.

(6) Bottom outlet turbine exhaust connections are preferred in order to avoid interference with the gantry crane.

Hydrocarbon Circulating Pumps

Purpose - This study evaluates alternative pumping configurations including vertical multi-stage versus horizontal single-stage pumps in series with vertical low head NPSH pumps.

Results & Conclusions - Three alternate systems were investigated. Alternate I utilizes 6 operating (1 spare) multi-stage high head vertical pumps. Alternates II and III utilize low head 4 operating (1 spare) vertical pumps to feed high head single stage horizontal pumps. Alternate II utilizes a single (spare) horizontal pump; Alternate III, 2 operating (1 spare) horizontal pumps.

Alternate III was recommended because of mechanical reliability and lower long term cost (reflecting the higher pump efficiencies).

Working Fluid Selection - The purpose of this study was to determine the most effective binary working fluids at different periods of plant life as the brine temperature decreases, based on varying mixtures of commercially available isopentane, isobutane, and propane. The study is based on an initial downhole temperature of 360°F and a temperature at the end of 30-years operation of 338°F (assuming full reservoir development).

Results and Conclusions - It was determined that the 80 mol% isobutane 20 mol% isopentane mix results in enhanced plant power production economics if used over the entire plant life. The thermodynamic properties of the 80 mol% isobutane 20 mol% isopentane mixture have not been firmly fixed. Some bench scale experimental work has been conducted by C. F. Braun for EPRI. Results from those tests have been compared to the state points produced by various thermodynamic correlations and the need for further resolution identified.

Brine Supply System

Purpose - During the flash versus binary cycle study a significant price difference between single-phase and two-phase brine delivery for the binary cycle was identified. The purpose of this study was to evaluate the impact of this price difference and to determine which type of brine delivery would result in lowest plant power production cost.

Results and Conclusions - With a fixed O&M cost, during the first few years of the plant life, the two-phase brine feed system results in lowest busbar power cost, with both a 75 psia and 85 psia two-phase supply resulting in an approximate one mill per KWH lower cost.

During the period of plant life between year 5 and 12 all three feed conditions produce approximately equivalent (within 1/2 mill) busbar cost. At plant life beyond the year 12 period, a 75 psia two-phase feed case becomes more attractive, but the difference between the cases remains at less than one mill difference through year 18.

In two-phase feed cases, considerably more equipment and controls are required than in the single-phase case to 1) separate the steam from the brine, 2) remove inerts from the steam and 3) remove sand from the brine. It is believed that these additional steps will complicate operation and adversely affect plant reliability. In fact these factors could result in additional operating expenses (i.e., for sand removal and steam lost in the inerts vent) which would more than offset the $800/day difference (@ 70% availability) in busbar cost at one mill/KWH.

Therefore, single-phase brine feed has been recommended.

Cooling System

Purpose - This study involved the evaluation of a system employing a "wet/dry" cooling tower to achieve water conservation. R. W. Beck and Associates were engaged to develop parametric analyses on varying combinations of wet and dry systems as applied to the Heber Plant using their computerized program developed in conjunction with similar studies they have performed for EPRI.

Results and Conclusions - R. W. Beck's cooling system study indicates that a "wet/dry" system could be employed at Heber. However, the climatological history at Heber leads to an evaluation showing the "all wet" system to be economically more attractive at this time. A cost increase (penalty) of 7 to 18 mills/KWH would result from use of the "wet/dry" system compared to the more economical "all wet" system. This increase translates into a 19-57 percent busbar cost penalty.

Turbine Generator Ratings - A study evaluation of the technical feasibility and cost impact of installing two half capacity turbines (instead of one full capacity turbine) at Heber was performed.

Several different configurations were evaluated. Use of a two-train concept would increase the flexibility of operation over the one train concept. Smaller load change increments would be possible. Minimum station load would be decreased. Failure of a component in a single train would result in a 32 MWe load drop instead of 65 MWe.

The two-train concept would also allow for evaluation of two competing turbines (i.e., one radial inflow and one axial flow) on a side-by-side basis. The mechanical reliability, operating and control characteristics, and unit efficiencies can be compared and evaluated. Experimentation with process variables could be accomplished on one train without the risk of a complete plant shutdown.

The disadvantage of the two train concept appears to be a significantly increased capital cost of the plant. This evaluation is currently nearing completion, and there are no conclusions to report at this time.

Dup

HEAT EXCHANGER MODULE TEST

(RP1094-1)

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The heat exchanger module test is an EPRI/DOE cooperative field test of shell-and-tube heat exchangers to be performed with brine from Chevron Resources Company's Heber, California, field. Overall heat transfer coefficients will be measured with isobutane and a mixture of isobutane-isopentane as the working fluid in a simulated power cycle.

The objectives of the project are:

* Verify the performance of state-of-the-art heat exchangers in geothermal service;

* Verify the heat exchangers' performance heating either selected pure light hydrocarbons or selected mixtures of light hydrocarbons in the vicinity of their respective critical pressures and temperatures;

* Establish overall heat transfer coefficients that might be used for design of commercial-size geothermal power plants using the same geothermal brine and light hydrocarbon working fluids;

* Define the effects of heat exchanger cleaning techniques on subsequent heat exchanger performance;

* Establish overall condensing coefficients that might be used for design of commercial-size geothermal power plants using the same light hydrocarbon working fluids;

* Perform and investigate the above under representative field operating conditions during which the production well will be pumped.

The Lawrence Berkeley Laboratory has been assigned management responsibility for DOE's portion of the project. The mechanism for cooperation between LBL and EPRI on this project is the Project Group, consisting of one representative from EPRI and one from LBL. A project manager, reporting to the Project Group, provides the day-to-day contact with the contractor including technical direction, schedule control, and invoice review and approval.

Because it is a cooperative project and not jointly funded, the two sponsoring organizations have each assumed certain responsibilities. LBL is responsible for the system design, procurement of the hardware and analysis of the data from the tests. EPRI is responsible for the construction and operation of the test apparatus and distribution of the final report. The project manager is responsible for writing the final report.

The main emphasis will be on the primary brine/hydrocarbon heat exchangers. This heat exchanger train consists of six exchangers in series; the brine in the tubes and the hydrocarbon in the shell. Table I lists the main features of the primary heat exchangers.

Table I

PRIMARY HEAT EXCHANGER DETAILS

Number of tubes:	62
Tube length:	24 ft.
Tube size:	3/4 in. OD, 16 ga.
Tube material:	carbon steel
Tube pitch:	15/16 in., triangular
Shell ID:	8-3/4 in.
Baffle spacing:	12 in.
Area per exchanger:	292 ft^2

The heat exchanger module test consists of three fluid loops: brine, hydrocarbon, and cooling water. The three loops are interconnected through the primary brine/hydrocarbon heat exchanger train and the desuperheater-condenser-subcooler train. The heat load is then rejected to the atmosphere in a wet cooling tower. The high pressure (heater) portion of the hydrocarbon loop is separated from the low pressure (condenser) portion by a pressure-reducing valve simulating a turbine.

The working fluids will be heated at supercritical pressures (600 psia) and the test is designed to gain insight into the behavior and heat transfer rates of the working fluids near the critical point. In particular, the working fluid mixture of isobutane and isopentane will be studied to observe any "fractionation" or unstable flow behavior that might occur due to vaporization of the mixture components at different locations in the heat exchangers.

Data from the test will be compared with predicted values using various models, such as the film coefficients predicted by the LBL SIZEHX code. The heat exchanger manufacturer will be asked to predict the performance of his units under the test conditions and these predictions will be compared to the test data. The test data will also be compared with predictions made using available correlations and film coefficients being measured in LBL's Binary Fluid Experiment.

In order to reduce the head required from the circulating pump, the hydrocarbon will be condensed at 250 psia (200°F) during primary heat exchanger runs. The subcooler will reduce the liquid hydrocarbon temperature to 120°F entering the primary heat exchangers.

To look at condensing coefficients, the hydrocarbon flow will be reduced and the system pressure dropped to 95 psia (120°F). Tests will then be run to obtain data on the condensing coefficient versus condensate loading.

An initial series of tests with isobutane will be run, to be followed with an 80/20 mixture of isobutane and isopentane. Several 200-hour runs separated by tubeside cleanings will be made to look at the effectiveness of the cleaning method.

The schedule calls for test operation to begin in mid-September 1978. Three months of testing have been planned. All the heat exchangers, de-superheater, condenser, subcooler, cooling tower, and hydrocarbon circulating pump are on hand. The contractor, Colley Engineers and Constructors, Gardena, California, who will design, fabricate, and operate the loop, is presently working on the system design.

RADIAL ORGANIC TURBINE DESIGN STUDY

(RP928-3)

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The contract was given to basically study the application of a radial inflow turbine to Geothermal Power Recovery and show the feasibility of applying this to various Geothermal sites and specifically to the San Diego Gas & Electric Facility at Heber, CA.

The final report is now complete and ready for issue, subject to a few minor revisions.

Previous reports given at Warm Springs and at an EPRI update meeting in the early part of the year, covered the basic analysis and the mechanical functioning of the machine.

This report will cover some of the highlights of the previous presentations and an update on the more recent work.

The first report showed the considerable effect on the cycle that the condensing temperature has on power and efficiency. The data have been more specifically analyzed for the Heber application and Fig. 1 shows the fall-off in net output as the condensing temperature increases. The data are shown for two inlet conditions, the higher curve taking into account the energy that is normally lost in an upstream throttling valve, a valve that is unnecessary with the variable nozzle configuration.

Fig. 2 shows how the mass flow has to be increased to maintain power as the condensing temperature increases. The curve assumes the brine mass flow and will be increased to match. The inlet temperature will be maintained. In practice, the increased heat load on the brine system will result in further increases in the butane mixture mass flow.

Working Fluid Rotoflow has analyzed three different working fluids and submitted the results to E.P.R.I. The biggest question has been where exactly to place the condensation line. This is still not exactly determined and may vary appreciably with small changes in composition. It is significant that the radial inflow turbine is insensitive to this and can tolerate large quantities of condensing vapor in the wheel. Units are running with up to 45% liquid at the discharge and most hydrocarbon expanders with radial turbines operate with up to 15% liquid at the discharge and 2% to 3% at the inlet where the gas carries over from an inlet knock-out drum.

Recently, the significant decisions have been to stick to an 80/20 mix of iso-butane and pentane, and stick to this for the life of the unit at Heber.

Shutdown Potential Control in the nozzles permits all the available energy to be dissipated across the turbine, and also permits a tighter control of the machine. The latter feature permits more accurate speed and phase control and is of particular significance during shutdown. This is because of the low inertia of the nozzles and Fig. 3 shows how a full load overspeed rejection can be controlled using the nozzles.

It is also useful to know that the overspeed protection is being used all the time and any malfunction is caught well before any dangerous situation arises.

Change of 3 to 2 Wheel Concept One of the more significant decisions was to change the turbine concept from 3 to 2 wheel configuration for the 70 MWe applications to the Heber project. This has significant advantages in cost and lack of complexity over a 3-wheel system.

The single case back-to-back wheel configuration has been selected for the following reasons:

1. A third wheel casing costs almost as much as a two-wheel casing;

2. An over-large wheel adds considerable complexity and reduces ease of maintenance;

3. Putting the flow through one casing reduces the amount of piping involved and cost of controls.

However, this does not preclude the multiple casing concept which still can apply to other than the Heber application, i.e.: a plant with high enthalpy drop can easily take the pressure down in two stages with the first stage as a single wheel and the second as a double back-to-back unit, handling increased flow. The generators we are using will handle inputs at either end, so increased or reduced power installations can be covered with turbine modules added or subtracted from a particular case (see Fig. 4).

Mechanical Features Briefly, we will go over the mechanical features of the machine, starting with the shaft and methods of assembly.

The power cartridge contains the bearings, seals, wheels and nozzle assembly, i.e.: the essential components that have to be and remain concentric regardless of pressure and thermal distortion.

Fig. 5 shows how this module lifts in and out of the assembly, and Fig. 6 shows how the module is assembled or disassembled in the field using simple equipment. We visualize that a spare power module would be held on the site and this would enable rapid turn-around, particularly in the early days of installation. Thus, if a wheel were damaged due to a foreign object going through, a quick change could be made, and the wheels replaced without losing excessive generating time.

Some other features are illustrated by the cross-section shown in Fig. 7.

For the Heber application, the wheels are aluminum castings and we are in the process of casting wheels this size for a large capacity refrigeration system for the Air Force. The foundry chosen has successfully cast this diameter and larger.

The bearings are integral journal-and-thrust, of patented high-speed design, and are large enough to take the axial loads superimposed by as much as .5g axial load on the alternator.

The labyrinth seals are non-contacting for long life and pressure balanced using the bearings as gas seals, which is a common practice with hydrocarbon expanders.

The shaft is a stiff shaft system which has no criticals in the running range, which is beneficial for long seal life and maintaining accurate wheel tip clearances; also the turbine and the generator are both able to stop without the need for barring (i.e.: slowly turning the shaft to prevent sag).

The castings are sealed with packing held in by a retaining plate, and this prevents the nipping of the seal at the joint line which can be a problem with this type of seal.

Generator The generators we are using are well established units developed for the gas turbine industry, hydrogen-cooled for greater efficiency and able to take inputs at both ends if necessary.

The coupling between turbine and generator follows gas turbine practice and utilizes a Bendix flexible diaphragm or similar type of coupling.

These have been developed for high powers, i.e. over 100,000 H,P., and have been in use for many years. It is possible that rigid couplings might be used, but this would require exceptional alignment of the turbine and generator; thermal compensation on the expander case and generator, and some protection against seismic shock. Even larger reactions during transients would tend to throw the units out of line and lead to possible bearing problems.

Initially, therefore, we propose the flexible coupling, as this has the following advantages:

1. Can accommodate mis-alignment due to thermal, seismic and synchronising on short circuit disturbances.

2. In the event of axial seismic shocks, the diaphragm flexibility permits part of the axial load of the generator rotor to be supported by bump stops in the generator casing.

3. Change of a power module is more simply effected without the need for exceptionally accurate realignment checks.

4. The mass of the overhung parts is minimized, permitting a stiff shaft construction in all criticals above the design speed.

Seal System Another area that has been more recently questioned is the choice of a suitable seal system.

We have selected a labyrinth seal system for several reasons:

1. The life of a labyrinth seal is good and Rotoflow has extensive background with this type of seal.

2. The leakage of process gas can be minimized by selection of a controlled back pressure and is completely recovered.

3. A captive nitrogen seal backed by a high pressure oil seal (combined with the bearings) prevents the use of excessive quantities of nitrogen.

Fig. 8 shows the configuration of the seals and how the nitrogen is fed in so that there is no contamination of the working fluid by the oil.

This system is by no means the only method of sealing the gas and if no nitrogen were available, an alternate system is available using heat to drive off the working gas from the oil.

Manufacturing Schedule Fig. 9 shows our best estimate at this time of how long it will take to manufacture the complete unit.

We have more recently been requested to examine a half-size unit, and this seems to be satisfactory, with almost identical performances to the full-size machine.

The casings and diameters are almost identical to the full-size machine, the only change being the size of flanges on the main casings. By this means the demonstration of the machine size proves out nearly all the conceptual approach of the full size machine.

Therefore, it is not anticipated at this time that the half-size machine will have any different manufacturing cycle, to the full flow unit.

PRELIMINARY DESIGN OF AXIAL FLOW HYDROCARBON TURBINE GENERATOR SET FOR GEOTHERMAL APPLICATIONS

RESEARCH PROJECT #928-1

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Introduction The goal of this research project is to demonstrate the feasibility of the 65 MW axial design double flow turbine generator for use with a variety of hydrocarbon mixtures as the motive fluid. The primary objective of this project has been achieved in that a 65 MW axial double flow turbine concept has been proposed and the design is within the present state of the art. The axial blade path was designed to use an 80% iso-butane, 20% iso-pentane mixture. This blade path was investigated throughout a wide range of operating conditions for this mixture as well as a mixture of 90% iso-butane, 10% propane, and another mixture of "commercial" iso-butane. Tasks 1 thru 18 covered the gas properties, blade path design (both aerodynamic and mechanical), and the mechanical design of the casing, rotor, assembly features, as well as the specification of seals, bearings, and instrumentation. Task 19, which was just recently added, covers the redesign of the blade path for a lower thermal source field. Specifically, a 300°F field utilizing a 50% iso-butane, 50% propane mixture as the motive fluid for the axial flow turbine.

Thermodynamics The gas properties used in this evaluation were calculated by the Elliott Company using modified Benedict-Webb Reuben equations-of-state. The Mollier charts for each of the gas mixtures of Tasks 1 thru 18 were prepared from this evaluation. For Task 19, an additional Mollier chart of the 50% iso-butane, 50% propane will also be supplied. A study to demonstrate the sensitivity of the process to changes in the mixture purity was completed for the original mixtures. The same evaluation will be completed for the 50/50 mixture. A review of equations, other than BWR, for computing the gas properties was also investigated. It was our recommendation that the gas mixture property data should be verified by experimental data so that the various designs could be properly evaluated. E.P.R.I. has followed up with an experimental program of gas properties.

Aerodynamics Tasks 1 thru 18 required the design of a turbine blade path using an 80/20 mixture. The turbine performance was computed for the other gas mixtures utilizing this fixed blade path. The blade path efficiency at design, 80/20 mixture, was 88%. This blade path had an efficiency of 86% using the "commercial" iso-butane and 85% using the 90/10 mixture. Task 19 will require a new turbine blade path design. The 50/50 mixture available energy convertable to mechanical power is on the order of 25 BTU/lb. The previous cycle motive fluids had 30 BTU/lb available for power conversion. Due to the lower available energy, the parasitic losses of the inlet and exhaust gas flow path and the mechanical power losses of the bearings and seals will have a greater impact on the overall turbine efficiency. The 80/20 mixture had an overall efficiency of 82%. For Task 19, we expect to hold this efficiency even with the lower available energy.

Mechanical Design The unit is designed with a barrel type construction. The barrel type construction allows for complete sealing of the endwalls to minimize gas leakage. Continuous o-rings are used on both ends of the casing to provide positive sealing of the joint. There are no three-way joints, as is common with horizontal split-line construction, which could present a potential leak of the hazardous hydrocarbon mixtures.

The rotating shaft-end gas seal is a proven design. This seal is a mechanical contact type which uses a rotating carbon ring. It has been used extensively in the petrochemical industry on centrifugal compressors. This seal is used for sealing gases such as methane, propane, ethylene, etc. These seals have been used extensively in services having more severe operating conditions, (i.e. temperature, pressure, rubbing velocity) than are present in an expander generator system. The proposed seal has the feature of positively shutting in the pressurized gas, once the unit is shut down. Additionally, the oil system can be shut down and the seal will retain the gas under pressure as a result of its unique shutdown pistons. This feature has proved successful with many different kinds of gases, including hydrogen.

Normal routine maintenance, such as inspection or replacement of bearings and/or seals, does not require the main casing to be opened up, therefore, the vertical split line seals do not have to be broken. Maintenance of the bearings and shaft-end seals can be accomplished in three or four shifts. For a complete disassembly of the rotor, the process piping does not have to be broken and removed.

Complete instrumentation is supplied with the unit in the form of vibration probes on the shaft and internal instrumentation in the blade path. Pressures and temperatures through the blade path will be recorded in order to evaluate unit performance. Task 19 requires investigation of the physical site of the casing in order to accommodate the additional flow requirements. Hydrotest specifications and other code requirements will be investigated.

Control The proposed control scheme included basic geothermal components such as condenser, pumps, vapor generator and turbine. Reviewing this system, Elliott recommended a pressure control based on the bypass of liquid and a temperature controller which could regulate the brine flow as a result of motive fluid vapor temperature in the heat exchanger. A variety of valves are required; one valve would bypass vapor around the turbine during startup and also circulate the gas through the loop without the turbine on line. The shaft seal we have recommended for this design allows the easy evacuation of the loop since this seal will permit a vacuum to be pulled, without pulling in air from the atmosphere.

Summary

1. The turbine aerodynamic stages are adapted from proven gas and steam turbine vane profiles. These are well within the state of the art.

2. Turbine shaft seals are well proven components designed to keep the gas within the system to avoid hazardous conditions.. even on loss of seal oil!

3. The axial turbine mechanical design is well within the present state of the art. The proposed design should be able to meet or accommodate any specific customer specifications.

GEOTHERMAL DISTRICT HEATING AT MAMMOTH LAKES

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Introduction In addition to many geothermal power generation programs, Southern California Edison Company (SCE) is also studying the utilization of geothermal energy for non-electric purposes. Under study is a plan to use geothermal energy for space heating in the ski resort community of Mammoth Lakes, California.

Mammoth Lakes is an ideal study location for implementing a "Geothermal District Heating" system. It has a large winter electric heating load within a fairly concentrated area and it has a nearby geothermal resource, Casa Diablo Hot Springs, located within three miles of the community.

Such a geothermal heating system at Mammoth Lakes would enable SCE to redirect its electric generating capacity presently serving Mammoth electric winter heating load to other new load areas. This would assist in postponing the construction of new SCE electric generating plants. To develop such a heating concept at Mammoth, a feasibility study has been completed and a demonstration project is underway.

Feasibility Study Such a concept appears feasible, based on the recently completed feasibility study which was funded by the Department of Energy and performed by the Ben Holt Company of Pasadena, SCE, Magma Energy, Inc., and Ayres Associates.

The feasibility study, performed over an 18 month period, considered a number of aspects of a Geothermal District Heating system to assess whether such a system serving Mammoth Lakes would be practicable.

The areas of assessment in the study include (1) hot water distributing system; (2) design of water and space heating systems; (3) reservoir potential of the geothermal resource; (4) environmental impact; (5) economics; and (6) permit requirements.

Simply stated, the assessment of the individual items of study is as follows:

1. Distribution System: The design of the hot water distribution system consists of a number of wells from which geothermal water at a temperature of 340°F would be pumped, passed through heat exchangers and then pumped back into the ground at about 200°F. A secondary heating loop, consisting of a mixture of fresh water and anti-freeze would be heated to 200°F by the geothermal water in the heat exchangers, and then pumped to several hot water storage tanks located near the community.

   A distribution piping system would carry the heated water by gravity from the tanks to individual homes, resorts, condominiums and businesses. After giving up its heat, the water would be collected and recycled to the heat exchanger plant for reheating and reuse.

2. Water and Space Heating Systems: Several types of space heaters were studied for new installations and for retrofitting, within each building, including central forced air units, and wall and baseboard type heaters. These operate on the same principle as the free standing room radiators from years past. The heat output is controlled by varying the flow rate of hot water through the heater.

3. Reservoir Potential: The reservoir assessment portion of the study indicated that the 90acre resource area, Casa Diablo Hot Springs, probably contains sufficient energy to support a fully developed district heating system. Additional wellflow testing will be required on a long-term basis to verify the capacity of the reservoir before a major commitment can be made.

4. Environmental Impact: A preliminary environmental assessment performed as part of the study identified no adverse impacts which would prevent the construction and operation of the geothermal system. After initial construction, the system will be inherently clean, quiet, safe, and unobtrusive.

5. Economics: Two major penalties to the economics of the geothermal heating system were identified in the study.

   First, is the high cost of the large diameter, three mile supply and return pipelines between the geothermal resource area and the community. This cost will be over half the cost of the entire installed system. If a geothermal resource could be found closer to or in the community the economics would be improved significantly.

   Second, the capacity factor of the system is estimated to be in the order of only about 20 percent. In other words, the system would be used, and therefore, earning revenue only about 20 percent of the time. This is due to the mild weather during the summer months, requiring very little heating of the buildings.

Part of the follow-up study investigated "off peak" uses of the system, such as summertime swimming pool and jacuzzi heating. Such additional uses will improve the economics of the system.

Upon completion of the system design, the capital cost of the completely installed system was estimated to be in the order of $15 million for a system supplying 52 megawatts of heating energy.

The annual costs for heating typical buildings in the community with Geothermal District Heating were shown to be about 25%higher initially than with existing electric or gas sources. However, the geothermal system will probably become the lower cost heating source as the price of fossil fuels continues to escalate.

6. Permit Requirements: The permit study task revealed that a total of 14 permits would be required from 11 governmental agencies. It could take as long as nine months to prepare an Environmental Impact Report and then as long as 48 months to obtain a U.S. Forest Service (USFS) special use permit - a total of 57 months.

The determination of the feasibility study is that such a system is technically feasible using current technology. Indeed, several large-scale geothermal district heating systems have been operating successfully for many years throughout the world.

Demonstration Project In addition to the feasibility study, as described in the foregoing, another activity toward developing the geothermal resource at Mammoth Lakes is under way. The California Energy Resources Conservation and Development Commission, and SCE funded construction of an operational geothermal system to demonstrate to the local builders, homeowners, and interested agencies how an actual geothermal district heating system operates. The demonstration system is located in Casa Diablo Hot Springs.

In this demonstration system, geothermal fluid is pumped through heat exchangers where it gives up its heat to a secondary fresh water loop which carries the heat to a variety of space heaters located in lumber store buildings. A section of sidewalk between buildings is also heated by the system to demonstrate snow-melting capability.

In addition to demonstrating the operation of the system, it is planned to collect data on the performance of the heat exchangers, the space heaters and associated control systems, as well as geothermal reservoir data. This pilot project was placed in service in January 1978.

Technical problems with the production well and pump have, however, interrupted the operation of the facility. The information generated by this demonstration project and the feasibility study will be a valuable step toward utilizing the more moderate temperature geothermal energy resources found throughout the western United States.

The next step for SCE is to perform a critical "inhouse" review of the concept, using all available data including data from these federal and state projects as inputs. SCE plans to accomplish this task within the next year.

THE GEYSERS POWER PLANT H_2S ABATEMENT RESEARCH AND DEVELOPMENT

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I IRON SYSTEM

All existing units (1-11) and Unit 12 (under construction) at The Geysers are equipped with direct contact condensers. In these units the condensing steam is mixed with a very large volume of circulating water causing about two-thirds of the incoming hydrogen sulfide to be dissolved in the water carried to the cooling towers and one-third to be removed with the noncondensible gases.

Soluble iron compounds are added to the circulating water to reduce H_2S emissions. The iron process operates by promoting the oxidation of hydrogen sulfide (H_2S) by atmospheric oxygen using the following chemical reactions. In Reaction (1) hydrogen sulfide is oxidized by two ferric ions (Fe^{+++}) to elemental sulfur (S°). Reaction (2) regenerates the ferrous ion (Fe^{++}) formed in Reaction (1) to ferric ion so that the iron can be reused in Reaction (1). The net reaction is shown in Equation (3) which states that H_2S is oxidized to water and free sulfur by atmospheric oxygen.

$$(1) \quad H_2S + 2Fe^{+++} \qquad 2Fe^{++} + S^\circ + 2H^+$$

$$(2) \quad 2Fe^{++} + 1/2\ O_2 + 2H^+ \qquad 2Fe^{+++} + H_2O$$

$$(3) \quad H_2S + 1/2\ O_2 \qquad H_2O + S^\circ$$

With this process the H_2S contained in the noncondensible gas stream (ejector offgases) from the condenser is treated by venting the gases into the cooling tower where they are scrubbed by the falling water. Early tests of cooling tower scrubbing efficiency at Units 1 and 2 were very promising. Continuously high efficiencies have not been observed at either Unit 4 or 11.

Improvements - Abatement Efficiency Several approaches are being attempted to improve the abatement efficiency. The iron feed location was changed to provide immediate oxygenation of the iron feed solution. Previous tests indicate that nickel was an effective agent but produced sludge so sticky that the unit clogged within two days. Small amounts of nickel were added to the iron solution to improve its catalytic ability. Vent gas distribution was analyzed to ensure that there was no shortcircuiting within the tower cells. Additional vent line distribution pipes were added to Unit 4. Tests have been conducted using H_2O_2 as an auxiliary oxidizing agent for the iron system.

Vent Gas Treatment The most promising approach at present appears to be the use of caustic soda in the aftercondenser water supply or vent gas line. H_2S dissolves readily in high pH solutions and would then be carried in solution to the cooling tower basin where it would be treated by iron and H_2O_2. In essence, the gaseous H_2S is converted to dissolved H_2S for treatment.

Demonstrate Long-Term Abatement The present data, although preliminary, indicated that the use of caustic in the aftercondenser or vent gas line will scrub the gaseous H_2S, and that the addition of H_2O_2 will abate the dissolved H_2S. It appears that these two additional chemicals can bring the iron system to 90 percent abatement efficiency. We have planned to demonstrate the ability to do this during a one week continuous test during the second quarter of 1978 at Unit 11.

Plant Operation The use of "iron" has produced more severe operational problems than had been anticipated. Previous studies by PGand E had indicated an increased corrosion rate, and this is occurring. However, because the iron system is presently operating on high H_2S units, the total solids produced are higher than observed at Unit 1 and severe clogging has occurred on heat exchanger loops and cooling tower water distribution nozzles. One serious problem has developed in that the solids (sludge) will accumulate in the cooling tower fill material. This is a low strength material, lightly held in place, and the increased weight causes the fill to fall, decreasing the cooling tower efficiency and requiring major cooling tower maintenance.

II. STRETFORD AND SURFACE CONDENSER SYSTEM

It became apparent to PGand E in early 1975 that the iron system would not be an "elegant" solution to the problem of H_2S abatement. Design decisions were required for Units 13, 14, and 15 in order to continue the expansion of The Geysers in a timely fashion. The decision was made to redesign the condensers from a direct contact condenser to a surface condenser. This results in a change in H_2S partitioning from 70 percent dissolved and 30 percent gaseous H_2S in the direct contact condenser to less than 10 percent dissolved and greater than

90 percent gaseous H_2S in the surface condenser. This gas stream is then to be treated by the Stretford process. The Stretford process has been in use for some years for the treatment of H_2S gas streams similar to those expected from the surface condenser. It is important to note that the Stretford process cannot economically be applied to the direct contact condenser units since only 30 percent of the H_2S is in the gaseous state.

Surface Condenser Efficiency The Stretford process itself is 99+ percent efficient. It will remove essentially all of the H_2S that reaches it as a gas. The overall H_2S abatement efficiency is, therefore, dependent upon the partitioning that occurs in the surface condenser. The predictions range from 80 percent to 98 percent. There is no means to verify these predictions until a full-scale condenser becomes available. Unit 15 will be the first unit to become operational with a surface condenser, and extensive tests are planned to determine the partitioning of H_2S.

Secondary Treatment The H_2S that is not vented to the Stretford process will be dissolved in the condensed steam carried to the cooling tower, air stripped, and released to the atmosphere. We have directed considerable effort into developing a secondary treatment system that could remove this H_2S, should it be required due to poor partitioning in the surface condenser. We have reviewed a number of approaches, including H_2O_2, chlorine, ozone, and steam or air stripping.

III. UPSTREAM SYSTEM (EIC PILOT PLANT)

PGand E searched for some years for a system that would remove H_2S in the steam ahead of the turbine. No approach appeared feasible until the work by EIC, funded by ERDA (now DOE), and the proposal by Deuterium.

EIC proposed an approach using copper sulfate to precipitate the H_2S as copper sulfide and subsequent regeneration to copper sulfate for reuse.

An evaluation of laboratory results, laboratory data, and field tests led PGand E to develop a proposal to DOE for a 100,000 lb/hr pilot plant (5 Mw) to be funded by DOE, and Geothermal Industry, at a cost of $2,000,000.

The upstream approach has several aspects that make it attractive; a high H_2S removal process that does not interfere with plant operation, removal of boron and ammonia, and treatment of venting steam during plant outages.

IV. ALTERNATIVE SYSTEMS

PGand E has been and will continue to be receptive to new or alternative approaches for H_2S abatement. Several reviews of H_2S abatement technology have been funded by various agencies. These include Stanford Research Institute, Midwest Research Institute, and Pacific-Sierra Research for Geonomics. None of these has revealed any new approaches.

GEOTHERMAL LOOP EXPERIMENTAL FACILITY - UPDATE

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Abstract The performance of San Diego Gas & Electric's Geothermal Loop Facility has been generally good. Comparison of initial flash/binary conversion cycle selection criteria to performance data has led to renewed interest in a flash cycle. Brine system performance has been generally successful but hampered by scale accumulation. Improved scale removal and control techniques are being evaluated. Geothermal steam and condensate systems have shown good steady state performance, but performance is adversely affected by upsets or oscillations. Brine injection well performance has been unpredictable; however, effluent treatment methods are giving promising results.

SAN DIEGO GAS & ELECTRIC COMPANY has been operating a Geothermal Loop Experimental Facility at the Niland reservoir in the Imperial Valley since May, 1976. The facility is jointly funded by San Diego Gas & Electric Company and the U. S. Department of Energy. The facility utilizes the high temperature, high salinity (HT/HS) brine resource of the Salton Sea (or Niland) Geothermal Anomaly. The purpose of the facility is to investigate the technical and economic feasibility of generating electric power from this type of resource. The facility is sized to generate a gross output of approximately 10 megawatts of electric power using a flash/binary cycle; however, to reduce costs and since the testing emphasis is on brine handling, an expansion valve is used in place of the turbine and generator. The performance to date of the cycle and the three major sub systems (brine, steam/condensate and binary) and future test plans are reviewed.

FLASH/BINARY PROCESS The flash energy conversion cycle is most commonly used to convert a liquid-dominated geothermal resource into electric power. In this cycle the geothermal brine is allowed to boil or flash generating generally low pressure steam. The steam fraction is then directed into a turbine. A binary process is commonly cited as an alternative conversion cycle. The binary cycle transfers the heat from the liquid state geothermal brine to a binary or working fluid. The binary fluid, in a vapor state upon heating, is directed to a turbine. Although the binary cycle requires more equipment and therefore generally higher plant investment than the flash cycle, the binary cycle is generally more efficient.

A modified process was selected for the Salton Sea Geothermal Loop Experimental Facility based on initial well and component field test results. The flash/binary cycle process flow used at the GLEF is shown in Figure #1. Initial field test results indicated that the binary process heat exchanger surfaces would rapidly foul with scale preventing acceptable heat transfer efficiency. Well flow test data showed a significant fraction of noncondensable gases. These gases, if passed through a flash cycle turbine, would significantly reduce the power output of the flash process. The flash/binary process was expected to avoid these problem areas.

The flash/binary process transfers heat to a working fluid from the geothermal brines without fouling by allowing only the flashed steam to contact the heat exchangers. Noncondensable gases can be separated from the condensed steam and vented without a significant reduction in power. These advantages may allow the flash/binary process to be used for a wide variety of geothermal fluids. However, the efficiency of the process suffers from the inherent losses associated with using the flashed steam as an intermediate heat transfer agent. Maximum available temperature of the brine is reduced by flashing when compared to a pure binary system unless infinite staging is accomplished. A loss in maximum working fluid temperature caused by heat exchanger ΔT is also inherent when compared to the flash process at an equivalent pressure.

In conclusion, the GLEF flash/binary cycle has demonstrated an ability to transfer the thermal energy of the brine to the clean working or binary fluid. However, the percentage of noncondensable gases in the brine and steam has been less than expected. This has led to renewed consideration of a flash conversion cycle. Steam purity may have to be improved if a flash cycle is implemented.

Brine System Performance Handling the high temperature/high salinity brine has proven to be critical to the operation of the plant. The major problem in handling the brines in the plant has been the rapid buildup of scale. The scale constricts the flow passages of pipes and seizes the moving components of valves and pumps.

Scale composition and rate of accumulation varies with temperature, brine composition and phase, fluid velocity and surface conditions. Scale rate is in the order of magnitude of 1 mil per hour. Scale accumulation in pipes has a doubly detrimental effect. In addition to reducing the cross sectional flow passage area, the scale creates a rough wall. This rough wall causes further pressure losses. The effect of the rough wall is an increase in the pipe flow friction factor. Increases in the friction factor of up to 2½ normal pipe data have been calculated.

Operational experience at the facility has shown that a balance is desirable in line sizing. If piping size is overly large, scale buildup is sometimes accelerated and scale removal becomes difficult. Sizing piping too small allows scale to quickly plug passages. Although operational experience is limited, an allowance for a scale buildup of 1 inch appears to be a reasonable order of magnitude for a balance. Thus design of piping should allow approximately 1 inch of scale to form prior to scale removal.

Scale formation also affects the operation and performance of moving components. These components must be designed to either accept scale formation, prevent scale from forming on critical points or provide for frequent removal of scale. Since the facility was designed with "off-the-shelf" hardware, only modifications to existing hardware have been attempted rather than a new design for handling scale. Modifications have included: opening clearances between moving interfaces (accepting scale to formation); adding packings, restricting brine exposure, adding gap fillers and purge flows to moving interfaces (preventing scale from forming on critical points); and adding in-line nozzles to impinge on moving parts (provide for frequent removal of scale). The combination of these modifications has accomplished significant improvements in operation and performance; however, further effort is required.

Instrumentation and controls is another area where significant improvements have been made but additional effort is needed. The two phase brine mixture supplied to the plant boundary has significant oscillations in pressure, flow and quality. This results in control and instrumentation problems. These problems are compounded by scaling of the sensors in the brine. Improved performance has resulted from installing proportional controllers (replacing on-off and step controllers), underground drain lines (replacing overhead lines which promoted flashing of saturated fluid), and adding constant bypass flows (minimizing control valve variations).

Injection well performance problems have lead to brine effluent treatment testing. Strainers and cyclone separators have not been successful. Settling tanks are being used with partial success. A clarifier system is being planned for future test activity.

Steam And Condensate System One-well steady state steam and condensate system performance has been better than expected. Scrubbers, located downstream of the flash drums, have been generally able to keep steady state steam purity to under 30 ppm (see Figure #2). Operation has been affected by the dissolved gases and mineral carryover in the steam and condensate. Dissolved gases have affected the pH of the condensate and minerals have caused scale formation. Scale and pH control of the condensate system is being developed.

The steam and condensate system are adversely affected by transients. Carryover increases significantly during plant upsets. Several days are required for the system to return to optimum performance. Improvements to control plant oscillations and transients are being planned.

Short-term scrubber and flash drum performance is not significantly sensitive to small changes in operating conditions. Daily changes in pressure, flash drum liquid level and scrub drain water supply have had little correlatable effect on steam purity.

In summary, steam and condensate system performance has been generally good for the GLEF conversion cycle. Future improvements to plant stability should further assist performance.

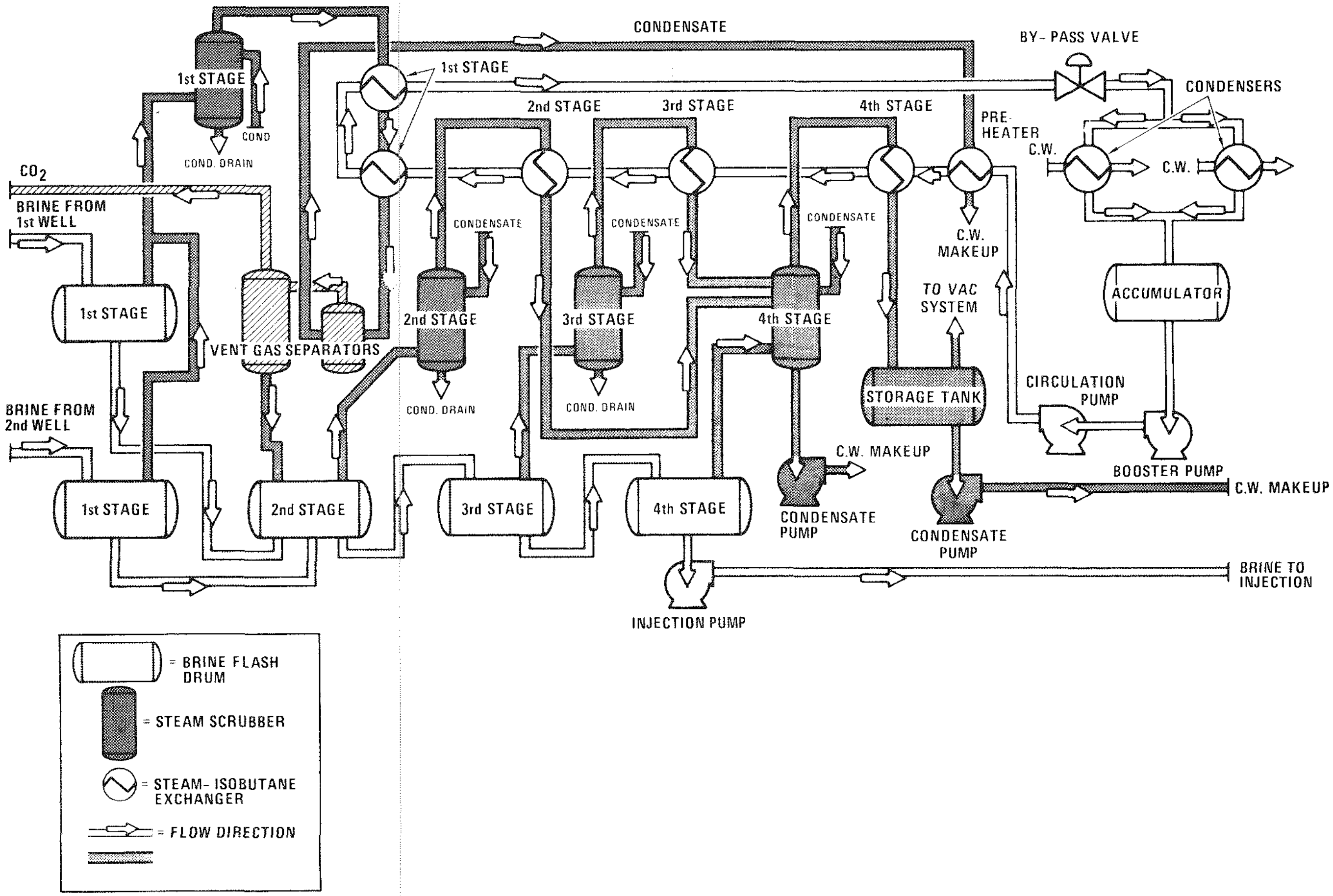
Binary System The binary system working fluid to date has been distilled water rather than isobutane which the facility was originally designed to utilize. Heat exchanger performance is therefore off design. Overall heat transfer coefficients of approximately 60 BTU/HR-FT^3-^{o}F have been observed. Although these values are low, no significant heat exchanger losses are expected if design conditions are approached.

Future Testing Engineering evaluation of GLEF data has resulted in renewed interest in a flash cycle. Future testing will emphasize brine handling with flash cycle conditions in conjunction with brine effluent treatment.

Summary In summary, the performance of the Geothermal Loop Experimental Facility to date has been generally successful. The facility has been able to handle the high temperature, high saline brine and extract thermal energy. Some performance losses have been observed primarily related to the deposition of scale. Future testing should further define the parameters associated with the scaling phenomenon and injection well performance.

Fig. 1 - **GEOTHERMAL LOOP EXPERIMENTAL FACILITY**

TYPICAL PROCESS FLOW DIAGRAM



STEAM SEPARATOR SAMPLES	pH	Na mg/Lit	NH_4–N mg/Lit
1st STAGE IN	6.30	5.3	240
1st STAGE OUT	6.40	1.0	285
2nd STAGE IN	8.60	5.0	210
2nd STAGE OUT	8.90	2.0	210
3rd STAGE IN	9.80	4.0	130
3rd STAGE OUT	9.80	2.0	135
4th STAGE IN	9.80	90.0	90
4th STAGE OUT	9.90	10.0	230

Fig. 2 - GLEF steam properties

GEOTHERMAL POWER PLANT COST SENSITIVITY STUDY

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Recently, the Public Service Company of New Mexico conducted a conceptual double flash design study of two locations in New Mexico. The intent of the study was to observe plant cost variation as a function of site location only (e.g., terrain, elevation, accessibility, temperature, etc.); reservoir conditions were assumed constant for both locations.

The locations consist of a high mountainous terrain area and a lower elevation level desert type area with the following design criteria:

Mountainous Terrain Site:

The site is located at an elevation of approximately 8750 feet above sea level and is in Uniformed Building Code Seismic Zone 3.

Weather:
Winds - prevailing from the South
Rainfall - not given
Snowfall - three (3) feet per hour (maximum)
Temperatures -
Summer: 70F Dry bulb
56F Wet bulb
Winter: 0F Dry bulb

Foundations:
Soil bearing pressures for foundations are assumed to be 3000 pounds per square foot

Structures:
Wind pressure (pounds per square foot):
Up to 30 foot height: 15
Up to 100 foot height: 20
Design live loads (pounds per square foot):
Roof: 20
Roof Snow Load: 75
Operating Floor: 125
Mezzanine: 125
Control Room: 75
Office Area: 50
Ground Floor: 400

Geothermal Steam Data:
Double Flash:
Turbine entry pressure/temperature(psia/F)
1st point of admission 103/330
2nd point of admission 27/244
The total mass flow to the turbine is distributed as follows:
1st admission point - 75%
2nd admission point - 25%

Low Level Terrain Site:

The site is located at an elevation of approximately 4200 feet above sea level and is in Uniformed Building Code Seismic Zone 2.

Weather:
Winds - maximum recorded from the south; prevailing from the north
Rainfall - yearly average, 8 inches
Snowfall - not given
Temperatures-
Summer: 43F Dry bulb
68F Wet bulb
Winter: 31F Dry bulb

Foundations:
Soil bearing pressures for foundations are assumed to be 3000 pounds per square foot

Structures:
Rain intensity (inches per hour): 1.5
Wind pressure (pounds per square foot):
Up to 30 foot height: 11
30 foot to 50 foot height: 18
50 foot to 100 foot height: 28
Design loads (pounds per square foot):
Roof: 20
Roof Snow Load: 30
Operating Floor: 125
Mezzanine: 125
Control Room: 75
Office Area: 50
Ground Floor: 400

Geothermal Steam Data:
Double Flash:
Turbine entry pressure/temperature (downstream of turbine throttle valve - psia/F)
1st point of admission 103/330
2nd point of admission 27/244
The total mass flow to the turbine is distributed as follows:
1st admission point - 75%
2nd admission point - 25%
The turbine back pressure is 4 inches Hg absolute.

Plant Site Arrangement

The gross plant capacity will be approximately 50,000 kW and will not be expanded due to economical well gathering size for a 50 MW generating capacity. The plant is generally comprised of four (4) major building blocks; the power building, the cooling tower and intake structure, the switchyard and the H_2S emission abatement system.

In determining space requirements and location and orientation of the major plant components, maps were used of the particular area under consideration. In arranging the major plant components, the following factors are emphasized:

1. The available level ground space.
2. Wind direction with respect to cooling tower location.
3. The approximate site location as provided.
4. Best relative location of power block, cooling tower, switchyard and H_2S abatement system. (The power block is arranged to accommodate the probable direction of the steam supply in relation to the plant site.)

Attached is a normalized plant cost estimate for both sites. It appears the low, level site plant costs are 4.2% higher than the mountainous site. The factors which directly contributed to the overall cost increase of the low, level site over the mountainous terrain site are:

1. The high wet bulb temperature (68°F) prevailing at the low level area had a considerable influence on the size and cost of the cooling tower and condensing equipment.
2. No significant civil/structural cost reduction resulting from the lesser site work because of the relatively flat terrain.
3. A minor increase in piping mainly due to the longer cooling water piping runs between the plant and the cooling tower.
4. Increased installation costs because an additional allowance has been made for anticipated travel and subsistence costs due to the remote location of the low, level site.
5. As a result of the above cost increases the low level project contingency and escalation increased accordingly.

In conclusion, the wet and dry bulb temperatures appear to be the cost sensitive parameter for a flashed cycle geothermal power plant. A level terrain can reduce cost, but not significantly. Therefore, in this particular case, the mountainous terrain site appeared the most economical.

50 MWe GEOTHERMAL PLANT
NORMALIZED COST COMPARISON
ESTIMATE SUMMARY FOR DOUBLE FLASH

DIRECT MATERIAL (INCL. MAJOR SUBCONTRACTS)

		Mountainous Terrain Quantity	Low, Level Terrain Quantity	Normalized Cost: Mountainous Terrain	Normalized Cost: Low, Level Terrain
Mechanical					
Turbine Generator	50 MWe (gross) - Approx. 325 tons	1 ea.	1 ea.	1.000	1.000
Heat Exchanges	Shell/Tube 700 SF total, 600 GPM	1 ea.	1 ea.	.001	.001
Condenser - Main	Horizontal Tube 54,000 SF, Approx. 110 tons	1 ea.	1 ea.	.100	.113
Condenser - Ejector	Shell/Tube 6,000 SF, Approx. 27 tons	1 ea.	1 ea.	.060	.073
Pumps - Circulating Water	Vertical Wet Pit Mixed Flow, 38,000 GPM	2 ea.	2 ea.	.090	.090
Cooling Towers	79,500 GPM	8 cells	11 cells	.250	.312
Other Mechanical	Incl. H_2S Abatement Facility	Lot	Lot	.590	.590
Subtotal				2.091	2.179
Electrical					
Main Transformer	54 MVA, 13.8kV - 115kV	1 ea.	1 ea.	.061	.061
Station Service Transformers	5/5.6 MVA, 13.8kV - 4.16kV	1 ea.	1 ea.	.005	.005
Station Service Transformers	2500kVA, 4.16kV - 480/227V	1 ea.	1 ea.	.003	.003
13.8kV,4.16kV,480V Switchgear	3000A, 1200A & 600A Metal Clad	20 Brkrs.	22 Brkrs.	.033	.033
Motor Control Center	Indoor	4 Sects.	4 Sects.	.002	.002
Raceway	Incl. Conduit & Tray	7500 LF	8600 LF	.004	.004
Wire and Cable	Incl. All Power and Control	34,700 LF	39,700 LF	.004	.004
Connection - P&C	All Sizes	2200 ea.	2250 ea.	.001	.001
Other Electrical	Incl. Lighting and Switchyard	-	-	.030	.030
Subtotal				.014	.014
Civil/Structural					
Concrete	Incl. Formwork, Rebar, Emb. Metal & Concrete	3200 CY	3400 CY	.088	.094
Structural Steel	Main Building and Yard Pipe Rack	200 T	210 T	.050	.050
Sitework		2.75 Acres	3.75 Acres	.095	.039
Other Civil Structural				.084	.095
Subtotal				.317	.279
Process Piping & Instrumentation					
Large Pipe	Main Stream - Carbon Steel Std. Wt., Remainder	3700 LF	4100 LF	.085	.088
Small Pipe	Primarily Stainless Steel, LT. WL.	2300 LF	2600 LF	.005	.005
Instrumentation				.024	.024
Insulation (Incl. Equipment)				.009	.010
Subtotal				.123	.128
	TOTAL DIRECT MATERIAL			2.545	2.600
	TOTAL INSTALLATION COSTS			.752	.857
	TOTAL FIELD COST			3.300	3.457
	Eng., Proc., Const. Services			.464	.464
	Contingency			.591	.621
	Escalation			.451	.466
	TOTAL PROJECT			4.806	5.008

THE ECONOMIC ATTRACTIVENESS OF GEOTHERMAL ENERGY IN THE PACIFIC NORTHWEST

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Introduction When selecting the next power plant type for addition to its existing resource mix, an electric utility typically considers: (1) the bus bar price of the electricity; (2) transmission system capital and operating costs; (3) total fixed (or "owner ship") costs versus operating (or "incremental") costs; (4) long-term levelized costs versus initial-year costs; (5) costs/kWh versus absolute cost in \$/yr revenue requirements; (6) impacts on near-term rate adjustments; and (7) existence of tax incentives and the ability of the Company to take advantage of them. In assessing the economics of a new resource type, such as geothermal, the uncertainties in cost estimates - due to limited construction and operating experience and the inherent variabilities of the resource itself - make any single-point estimate of resource economics almost meaningless for decision-making purposes.

As part of an ongoing program to evaluate the potential for future utilization of geothermal energy in the Pacific Northwest, Portland General Electric Company (PGE) has completed a probabilistic economic analysis to estimate the costs of geothermal electric power generation in Oregon. This has been accomplished through development and implementation of a computer program which uses a Monte Carlo simulation to allow inputs of probabilistic power plant and field variables. This program, called GEORISK, contains a financial model to analyze power plant construction costs, and two geothermal reservoir models to estimate fuel costs - one assuming PGE ownership of both reservoir and power plant, and one where PGE owns the plant and is supplied geothermal fluids by a resource company who owns and operates the reservoir. The program allows performance of sensitivity analyses to highlight the important variables ultimately affecting the cost and, thus, the attractiveness of a potential resource. It is also capable of providing estimates of delivered electricity costs to the PGE system from specific resource occurrences.

Structure of the GEORISK Program The GEORISK program uses a Monte Carlo routine which handles all functions connected with random sampling of the input probability distributions, accuracy checks of the distributions actually generated, and calculation of probability distributions for several output variables whose values are functions of the input probabilistic variables.

Once the inputs have been read and sample values obtained for the probabilistic variables, certain intermediate reservoir-related variables required by the Financial Model are calculated. These are: (1) number of production wells, reinjection wells, and dry holes; (2) cost per production well, reinjection well, and dry hole; and (3) total drilling costs.

The Financial Model calculates the levelized annual revenue requirements for the power plant and calculates fuel costs for two cases: (1) where a resource company owns the field and PGE owns the power plant; and (2) where PGE owns both the field and power plant. The PGE-owned fuel cost calculations were derived through use of the Company Financial Model, modified as required for the geothermal economic evaluation. The resource company-owned fuel cost calculations are based on a program developed by the Ben Holt Company which is stated to be similar to standard oil company financial practices. The power generation cost calculations and output routines are determined by a standard PGE computer program designed specifically for economic comparison of generation alternatives, modified for the geothermal economic evaluation.

The data used in the geothermal program consist of the following: (1) reservoir characteristics which, for modeling purposes, have been aggregated into a single variable designated MW_e/well; (2) field data (relationships between the number and cost of production wells, reinjection wells, and dry holes); (3) field costs (drilling, surface installation, capital additions, O&M); (4) power plant costs and other variables (MW rating, capital costs, O&M costs, transmission costs); and (5) financial data (rates of return for field and power plant, lease bonus payments, field royalties, state income taxes, ad valorem taxes, investment tax credits). The data concerning reservoir characteristics were taken from actual field experience in various locations throughout the world and from literature containing generic estimates of geothermal reservoir parameters. Field cost data were also taken from actual experience, but mostly reflect literature estimates. Power plant cost data were taken mainly from the literature and from estimates developed by contractors to EPRI for the Heber Demonstration Project. Transmission system costs are based on estimates by PGE's System Planning Department for various likely geothermal sites in Oregon. Financial assumptions for the power plant are standard values for PGE operations.

Preliminary Comparison of Resource Ownership Options As indicated in Table 1, an initial run of the GEORISK program, using "base case" values for all input variables, resulted in comparable first-year delivered energy costs (in 1980 dollars), at a 75% plant operating factor, for the two options evaluated. This surprising result (intuitively, it was felt that it would be advantageous for PGE to own the resource due to its lower cost of capital) is largely attributable to the following factors: (1) PGE, because of its present heavy construction schedule, cannot take advantage of intangible drilling tax deductions; and (2) interest costs during construction (AFDC) were not incorporated into the Holt program, whereas these costs are included in the PGE Financial Model.

In order to estimate the impact of including AFDC in the Holt subroutine, the 7% AFDC added to the field capital costs in the PGE-owned fuel cost model was determined. This value of AFDC was added to the mean values of the Holt field cost estimates so that both options would be based on identical in-service costs. A deterministic analysis was then conducted for both the Holt and PGE options. The results of this analysis (1980 initial-year delivered costs of 38.63 mills/kWh for the PGE option and 44.24 mills/kWh for the Holt option) substantiated our earlier belief that significant savings might be realized if PGE owned and developed the geothermal reservoir rather than simply buying fuel from a resource company.

To own and operate the resource, however, would require that PGE either accept the high risks associated with exploration, field testing and development of the reservoir, or purchase the reservoir outright from a resource company. The risks associated with construction of the first power plant on a new reservoir, and associated uncertainties regarding field production longevity, would also be borne by PGE, perhaps backed to a certain extent by government loan guarantees.

Sensitivity Analyses In order to evaluate the impact of changing input assumptions on the delivered energy cost, a sensitivity analysis of selected independent "base case" variables was accomplished. Not surprisingly, the sensitivity analyses indicated that reservoir quality (expressed in the model as MW_e/well) is the single most important parameter affecting cost. Figure 1 graphically illustrates the impact on delivered energy costs of varying the input value for MW_e per production well. For example, decreasing the MW_e/well (i.e., degrading reservoir quality) from 4.3 to 3.0 increases the delivered energy cost by approximately 12%.

Other sensitive variables include reservoir depth as related to increasing production well cost, geothermal resource depletion allowance assumptions, construction schedules and rate of return on investment to the field developer in the case of the Holt option. With respect to the latter, if a field developer commands a 20% return on investment (which is probably reasonable if depletion allowances and intangible drilling deductions are not made available to the industry) rather than the 15% assumed in the Holt program, delivered energy costs would increase 27%! While important, power plant capital costs are not as sensitive as many of the geothermal field-related variables. For example, as shown in Figure 2, a \$50/kW increase in plant capital cost adds approximately 1 mill/kWh to the initial-year delivered energy cost.

Comparison of Initial-Year Fixed and Variable Cost Components for Resource Ownership Options The economic results presented in the preceding section do not distinguish between the fixed and variable portion of power plant costs. It is the latter component which, in the Northwest, determines when and to what extent a generation resource is dispatched and integrated into the existing predominantly hydroelectric system.

The fixed portion of the plant represents initial capital costs that are "sunk" over the life of the project, whereas the variable charges (mostly fuel and O&M costs) are based to a large extent on the number of hours the plant is in operation. The variable component generally determines the order of resource "loading" or dispatch in an existing electrical generation system. Careful estimation of its initial magnitude is critical because variable charges are subject to escalation over the plant's lifetime.

We have assumed, for the option where a resource company owns the reservoir, that fuel costs to PGE are totally incremental (although one precedent for a portion of fuel costs being fixed under this arrangement is being established at the Heber field between Chevron Resources and San Diego Gas and Electric, where a demand charge may be included in the fuel contract). For the case where PGE owns and operates both field and power plant, a large portion of fuel costs are due to depreciation of capital investments and, hence, are fixed. Table 2 compares the fixed and variable portions of geothermal electricity costs for the two field ownership options.

As shown in Table 2, the incremental costs for a PGE-owned reservoir are estimated to be far less than those for a resource company-owned reservoir. The magnitude of the difference could affect the way (and timing) in which a geothermal plant fits into a utility's electrical generation mix and may influence the relative attractiveness of the two field ownership options to PGE. As geothermal plants will probably be operated as baseload installations, their penetration into a given electrical system depends upon how competitive the fixed and variable components are with other generation alternatives. For comparison, generic planning estimates by PGE indicate that the variable components for a 1200-MW_e nuclear plant and 600-MW_e coal plant located in the Northwest and equipped with scrubbers are, respectively, 5.7 mills/kWh and 16.0 mills/kWh (both are in initial-year operation 1980 dollars).

Levelized Costs To evaluate the lifetime costs of a 50-MW_e geothermal plant, 30-year levelized costs were calculated for both the Holt and PGE field ownership options and for a 1985 in-service plant. These calculations were based upon the mean or "base case" cost estimates for all variables (expressed in initial-year 1980 dollars) and an assumed 6%/year capital cost escalation rate and 5%/year operating cost escalation rate. For fuel costs, a 6%/year escalation rate was used for the Holt option, whereas a 3%/year escalation rate was considered more reasonable for a PGE-owned reservoir. Although there is no past experience on which to base an estimate of geothermal fuel cost escalation rates for the case where a resource company owns and develops the field (other than The Geysers which is considered atypical of proposed future contracts), our discussions with several resource companies indicate that they propose to escalate geothermal fuel cost based on escalation indices of an alternative fuel - be it coal, oil, or uranium - each of which is expected to increase by at least 6%/year over the foreseeable future. Conversations with San Diego Gas and Electric regarding their expectations for the Heber field confirm the reasonableness of assuming a 6% annual escalation in fuel costs under the Holt option. The assumption of a 3%/year escalation rate for a PGE-owned field is based on the largest portion of fuel costs being pre-in-service capital costs which are not subject to escalation. It was derived by assuming no fuel cost escalation due to initial field capital costs, lifetime capital additions equal to total initial drilling costs, and a 5%/year field O&M escalation rate.

Results of this 30-year levelized cost analysis for a 1985 50-MW_e geothermal plant operating at a 70% capacity factor are as follows: (1) 74-87 mills/kWh for the resource company-owned option, excluding AFDC; and (2) 60-66 mills/kWh for the PGE ownership option. For comparative purposes, generic cost studies by PGE for future nuclear plants and coal plants equipped with scrubbers in the Pacific Northwest indicate that these would result in 30-year levelized costs (1985 dollars) of 56 mills/kWh and 75 mills/kWh, respectively, at a 70% capacity factor. If one compares these 30-year levelized values, and the variable costs developed earlier, two important facts become apparent: (1) under both reservoir ownership options geothermal is less costly than a coal plant equipped with scrubbers and located in the Northwest; and (2) geothermal is nearly competitive with nuclear power on both a levelized and variable cost basis if PGE owns and operates the reservoir, but considerably more expensive with the resource company-owned option.

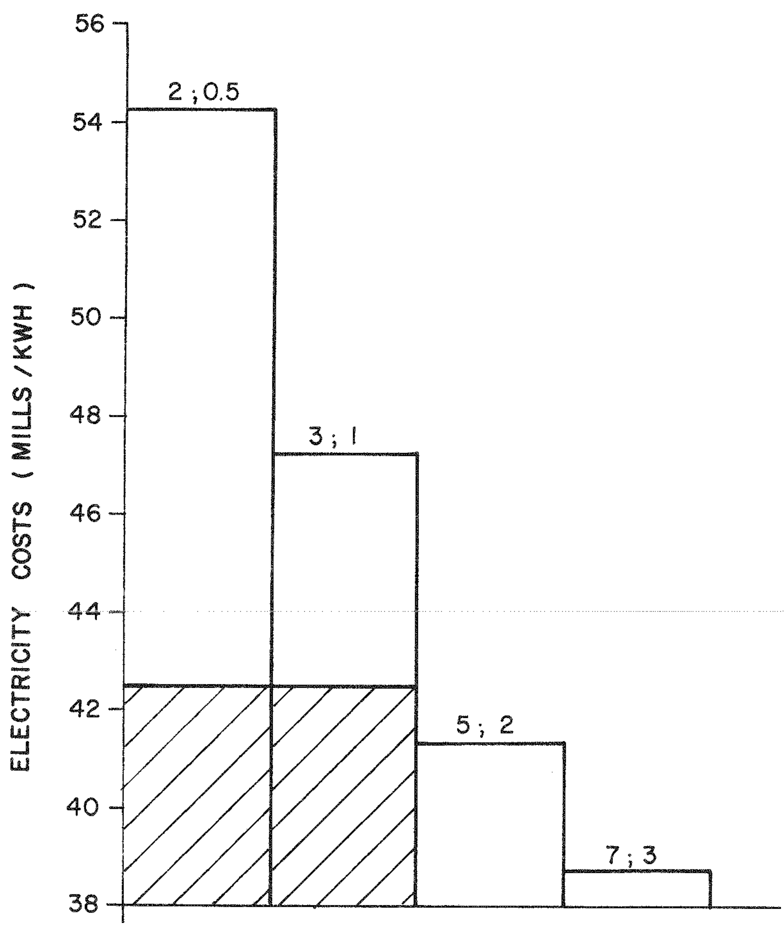
Conclusions PGE's analyses with GEORISK have enabled confirmation and quantification of two earlier subjective inferences. First, the range of estimates for geothermal levelized electricity costs from an "average reservoir" are within the bounds of competitive base load generation alternatives presently being planned by the Company for the 1980's. It should be remembered, however, that there are no assurances that a reservoir with "average" qualities will be encountered even through successful exploration ventures. Accordingly, delivered energy costs could be higher than those derived utilizing the mean values for field and power plant variables (see, for example, Table 1). Second, there appear to be significant long-term cost advantages to electric utilities that obtain at least a partial ownership arrangement in the geothermal field supplying fluids to a power plant. The magnitude of potential savings over simply "buying fuel" from a resource company would appear to be dependent upon: (1) terms of contractual arrangements between the supplier and utility for a specific reservoir, and, more importantly, (2) at what stage in a field's exploration and/or development the utility attempts to secure an ownership position.

With respect to the former, we believe that the large difference in variable costs attributable to the two resource ownership options evaluated to date with GEORISK is real. Furthermore, we fully expect that the resource companies will instigate innovative pricing concepts in contract negotiations to reduce this disadvantage and, correspondingly, the incentive for significant utility field ownership. This could be accomplished through inclusion of "demand charges" or similar mechanisms which represent a fixed fuel charge to the utility unaffected by the duration of plant operation. Incentive would still exist, however, for at least partial field ownership by the utility if this would afford the opportunity to hold fuel price escalation below that of competitive fossil or nuclear fuels.

The ability to obtain an ownership percentage in the field is probably directly related to the risk burden an individual utility is allowed to shoulder by either the stockholders and/or public utility commission-ratepayers. These risks will ultimately be evaluated by the individual utility against the probability and potential consequences of "gamblers' ruin" - through unsuccessful exploration ventures or reservoir failure.

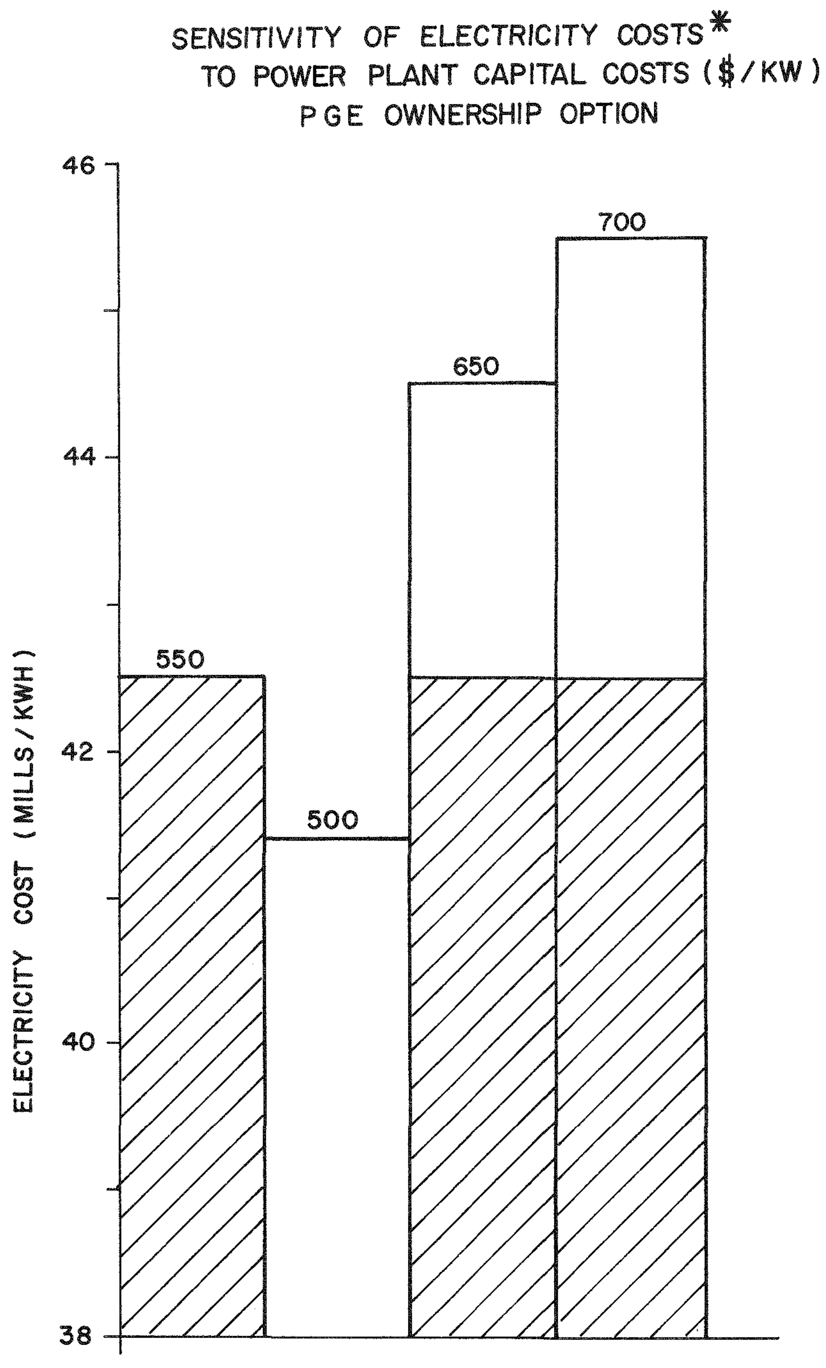
Figure 1

SENSITIVITY OF ELECTRICITY COSTS *
TO RESERVOIR QUALITY (MWe / Well)
PGE OWNERSHIP OPTION



*COSTS ARE INITIAL-YEAR VALUES IN 1980 $

Figure 2



*COSTS ARE INITIAL-YEAR SERVICE 1980 $

Table 1

Base Case Results—Major Variables*

Variable	Mean	Standard Deviation	Minimum	Maximum
Total Fixed Charges ($/kW-year)	82.39	19.24	38.94	128.94
Fuel Costs (mills/kWh):				
PGE-Owned	25.49	10.54	13.44	111.39
Resource Company-Owned (Holt)	24.83	7.61	16.33	86.91
Delivered Electricity Costs (mills/kWh):				
PGE-Owned	42.40	10.91	27.56	128.29
Resource Company-Owned (Holt)	41.72	7.99	30.09	139.07

(Calculated Values: Mean, Standard Deviation, Minimum, Maximum)

*-Initial year costs; 1980 in-service date
-No percentage depletion allowance
-Intangibles constitute 70% drilling costs
-No AFDC added for Holt option
-75% operating factor

Table 2

Comparison of Fixed and Variable Costs for PGE-Owned and Resource Company-Owned Reservoirs (Initial Year Costs, 1980 In-Service Year)

	PGE-Owned		Resource Company-Owned	
	Mean	Standard Deviation	Mean	Standard Deviation
Fixed Charges ($/kW-Yr)				
Power Plant & Transmission[1]	82.39	19.24	82.39	19.24
Fuel	142.20	69.24		Ø
(in mills/kWh at 75% operating factor)	21.64	10.54		
Variable Charges (mills/kWh)				
Fuel	3.84	Ø.	24.83	7.61
Plant & Transmission	3.50	Ø.	3.50	Ø
Total	7.34		28.33	

[1]Includes wheeling charges and transmission losses

[2]Assuming utility pays only as fuel is used. Some fixed charge for fuel, similar to SDG&E—Chevron Heber arrangement, is possible.

SOUTHERN LOUISIANA GEOPRESSURE-GEOTHERMAL

ENERGY RESOURCE ASSESSMENT

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Introduction

With the support provided by the Department of Energy and Gulf States Utilities Company the Petroleum Engineering Department of Louisiana State University has been able to build a large ongoing geopressure-geothermal research program. The research conducted can be separated into three general areas. The first research area includes geologic evaluations of the geopressure-geothermal resources of the Southern Louisiana. The second research area includes studies dealing with how the geopressure-geothermal resources could be commercially developed and identifying the geologic parameters important to the economic success of the resource development. The third research area includes studies dealing with possible field methods for measuring or otherwise estimating values of the geologic parameters important to the economic success of the resource development.

Resource Assessment

The geographic area of the geopressure-geothermal resource assessment study conducted by L.S.U. is shown in Figure 1. Basically, the area included all of Southern Louisiana (South of Baton Rouge) including the state-owned offshore area [1]. A similar study has been conducted by the University of Texas for the State of Texas.

The study area includes essentially all of the known geopressured areas of onshore Louisiana. A total of approximately 10,000 wells have been drilled in the study area. Approximately 60 percent of these wells studied were dry wildcats but at least one representative well from each of the approximately 700 oil and gas fields in the area was also included in the study.

The primary source of well data was well logs obtained from the files of the Louisiana Office of Conservation. The data taken from the logs included:

1. The well location
2. The depth and thickness of each sand body
3. The bottom hole temperature for each logging run
4. The mud weight used for each logging run

Since geopressured formations in South Louisiana generally do not occur at shallow depths, sand bodies shallower than 7000 ft. were not included in the data recorded. All recorded well data were stored on magnetic tape suitable for processing with the L.S.U. computer.

Approximated 60 percent of the 6000 wells included in the study required a mud weight in excess of 12 lb/gal in order to be drilled and were thus considered to have penetrated formations with a significant amount of abnormal pressure. The shallowest geopressured well in the study area was drilled to a depth of 7,504 ft. and the deepest geopressured well was drilled to a depth of 25,600 ft. The average geopressured well depth was approximately 13,000 ft. The maximum temperature observed in any well was 428°F, but an average temperature of about 200°F was more typical. The maximum total geopressured sand interval in any well was approximately 3000 ft., but an average total sand interval of approximately 434 ft. was more typical.

In order to identify regions in the study area with the greatest potential for the development of the geopressure-geothermal energy resource, the study area was divided into 40 blocks with each block being further subdivided into 5 depth intervals. For each of the resulting 200 units, the following quantities were calculated using the computer data files.

1. The volume of producible water
2. The maximum possible dissolved methane volume
3. The geothermal energy of the producible water
4. The hydraulic energy of the producible water

The producible water is the water which would flow from a well by natural means without use of artificial lift provided by a device such as a pump. An average system compressibility of $20x10^{-6}$ psi^{-1} was used in this calculation. The maximum possible dissolved methane is the volume of methane which would be present in the producible water if the water was completely saturated with gas. The gas solubility data of Culberson and McKetta were used in this calculation. The geothermal energy of the producible water was calculated as the heat content of the water from the bottom hole temperature to a discard temperature of 120°F. The surface conversion efficiency was neglected. The hydraulic energy of the producible water is the energy represented by the pressure-volume product of the water produced. A final surface pressure of zero was assumed at well abandonment.

The total geopressured-geothermal resource of the entire study area was computed to be 34.3 quads, which is the energy equivalent of about 6 billion barrels of oil. The potential dissolved methane accounts for 13.6 quads or about 40 percent of the total. Approximately 13.6 trillion SCF of methane could be dissolved in the producible water under fully saturated conditions. The geothermal energy accounts for 19.5 quads or 57 percent of the resource and the geohydraulic energy accounts for 1.2 quads or 3 percent of the total resource.

A total of sixty-three potential areas of interest were found in the preliminary geologic study of Southern Louisiana. The location of these prospects is indicated in Figure 1. In all of these prospects, the prospect area is removed from existing hydrocarbon production and thus will not involve any potential legal conflicts. In addition, drilling data in each area indicate a relatively high formation pressure.

At present, the sixty-three potential areas of interest are being ranked, and the most promising prospects are being mapped and studied in much greater detail. A preliminary ranking indicates that the better prospects tend to lie in the western half of the study area. The prospects in the eastern half of the study area were down-graded primarily because of poorer sand development, but it is entirely possible that several of these prospects will be attractive upon closer inspection. Eight of the 63 prospects that have been mapped in more detail all appear to be large geopressured aquifers. The location of the aquifers are shown in Figure 2.

Detailed geologic studies have been started on five prospects. It is hoped that a suitable site for a geopressured-geothermal test well can be selected by the end of this year. At present, the Southeast Pecan Island area appears to be the most promising test site. This area is identified as Site 2 on Figure 2.

Commercial Resource Utilization

Concurrent with the geologic studies made to locate and assess the magnitude of the geopressure-geothermal resource of Louisiana, computer studies have also been done investigating various schemes for commercial utilization of the resource. An economic evaluation of several schemes was done for a wide variety of aquifer properties in order to determine the geologic conditions needed for a commercial resource utilization.

Whitehead and McMullan [2] investigated the economics of electrical energy production from geopressured aquifers using an installation capable of utilizing the geothermal energy, the hydraulic energy, and the methane gas dissolved in the producible water. A flow diagram for the type of installation investigated is shown in Figure 3. The geohydraulic energy is converted through the use of a brine turbine, the geothermal energy through use of a binary-cycle plant, and the natural gas is obtained by using a gas/water separator. The natural gas is then converted to electric power using a conventional power plant. Aquifer behavior was computed as previously presented by Parmigiano [3] for pseudo steady state conditions and later verified by Bernard [4] using a more complete mathematical analysis. It was concluded that in order to be economically competitive at the present time with nuclear and conventional power plants, a geopressured aquifer must be operated at flow rates in excess of 100,000 barrels per day and the dissolved natural gas must exceed 30 SCF/bbl. A reservoir having a diameter of 30 miles, a thickness of 100 ft., and a permeability of 1000 md. would be capable of providing this flow rate for a period of 20 years.

Elemo [5] investigated the use of geopressured aquifers for the short-term storage of energy for the purpose of peak-shaving. This scheme involved pumping brine from one well completed in a shallow low pressure normal formation to a second well completed in a geopressured aquifer during low energy demand periods. During high demand periods, the flow would be allowed to reverse from the geopressured aquifer through a turbine and into the low pressure formation. The study indicated that approximately 50 percent of the stored energy could be converted. The results also indicate that the geopressured aquifer used for peak shaving could be quite small, contrasted with aquifers for energy production, which must be extremely large.

Techniques for Aquifer Evaluation

The economic evaluations conducted as part of the geopressured-geothermal resource utilization studies identified the following aquifer properties important to the economics of a commercial venture. The important aquifer properties include:

1. Dissolved methane gas content
2. Permeability
3. Pressure
4. Thickness
5. Areal Extent
6. Depth
7. Temperature
8. Porosity
9. Salinity

In the previous work done on the assessment of the geopressured-geothermal resource, it has been assumed that the formation brine is completely saturated with dissolved methane. There are no assurances that this is usually true. Also, the resource utilization studies have shown that the methane gas content is critical to the economic success of a commercial application.

A recent well test conducted by the Department of Energy under a 1.4 million dollar contract with OHRW and others produced more than three times the volume of gas which could be dissolved in the water. Unfortunately, the Delcombre geopressured test well [6] was located near a hydrocarbon reservoir and one would expect the presence of gas in this water.

Hadaegh [7] investigated experimentally the effect of sampling rate on the accuracy of a well test. It was hypothesized that a rapid test with the resulting large pressure drawdown would cause significant gas evolution in the reservoir. Since the gas mobility is quite high, this associated free gas could flow to the wellbore at a higher rate than the water from which it evolved. Thus, before steady state conditions are reached, gas production would be unrepresentatively high. Hadaegh verified this hypothesis in a high pressure long core flooding apparatus in which a Berea sandstone core (having a length of 6 ft. and a diameter of 2 inches) was mounted. Short flow tests conducted at high rates produced approximately twice the gas volume that was dissolved in the produced liquid. Tests conducted at low rates yielded a gas volume equal to the gas volume dissolved in the produced liquid. These results indicate that additional work must be done in order to develop well test criteria for evaluating the gas content of a geopressured aquifer.

Formation permeability, like gas content, is extremely important to the economic success of any geopressured energy project and cannot be obtained using conventional logging analysis. The existing techniques can only be applied to formations which contain hydrocarbons as well as water.

Ogbe [8] investigated the possibility of deriving aquifer permeabilities from electric logs. A correlation has been found to exist between the formation resistivity factor and permeability. The formation resistivity factor is easily determined from electric logs. The new technique was used to estimate the permeability of the geopressured sands of the Southeast Pecan Island prospect [9].

Conclusions

Considerable progress has been made over the past two years on the assessment of the geothermal-geopressure resources of Louisiana and on the economic evaluation of several schemes of resource utilization.

An on-going research program of resource assessment has now been developed with continued support from the Department of Energy expected for the next several years. The funds available from the Department of Energy are used to complete the geologic assessment of the Louisiana resource and to select a site for field testing the resource.

The research on schemes for commercial resource utilization and techniques for aquifer evaluation will continue with the support of Gulf States Utilities Company. Projects which are underway include the evaluation of water cycling as a technique for recovering dissolved gas in aquifers. The process would involve producing the water, separating the gas, and then reinjecting the water in injection wells completed in the same reservoir. In this manner, it would be possible to produce a much greater fraction of the gas present in the reservoir than through a simple pressure depletion mechanism.

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TEXAS GEOPRESSURED RESOURCE ASSESSMENT

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The Geopressured Geothermal resource as it is now understood is found in a band some 200-300 miles wide in the young Tertiary deposits of the Gulf Coast, both onshore and offshore, shown in Figure 1.

This is a somewhat unique geological resource in that it has the potential to provide both a source of high pressure hot water and a source of natural gas. This gas, of course, favorably influences the economics of resource utilization.

The Geopressured Geothermal resource is formed as the result of rapid accumulation of sediments in a marine environment, shown in Figure 2. These sediments were deposited by the large continental river systems that emptied into the Gulf.

These rivers carried a tremendous load of sands and muds and as these were dumped into the ocean, the sand and mud settled out and filled in the ocean forming land - like the present day Mississippi Delta.

In recent geological times, much of the land mass of Texas and Louisiana has been formed in this manner by the Mississippi, Rio Grande, and other rivers and their predecessors as they swept "Fire Hose Fashion" back and forth across the coast spewing out sediments.

These sediments have accumulated to depths as great as 50,000 feet. It is the top 25,000 feet, which consists of alternating sandstone and shale bodies, that has the potential to provide a geopressured geothermal resource.

As a result of the rapid accumulation of sediments and the unique nature of the Gulf Coast Geology, large sandstone bodies full of high pressure hot water and surrounded by impermeable insulating shale are formed. The fluids in these sands constitute the Geopressured Geothermal resource. See Figure 3.

The pressure in these zones increases dramatically because the fluids are trapped by the impermeable shales.

From Figure 4 one can see how the pressure increases from that which corresponds to the normal hydrostatic gradient (0.465 psi/foot of depth) above the Geopressured zone to pressures that correspond to gradients approaching twice the hydrostatic gradient (i.e. up to 1 psi/foot of depth). Note the rapid increase in pressure in the transition zone. Thus, if we had a resource at a depth of 15,000 feet, the pressure may approach 15,000 psi.

Similarly, due to the insulating nature of the isolating shales, the waters within these zones are at a higher temperature than would be indicated by the normal temperature gradient (1 to 1-1/2 °F/100 foot of depth). Note the increase in the geothermal gradient through the transition zone.

Typically, in a geopressured zone you would expect to encounter temperatures of 300°F at a depth of about 12,000 to 15,000 feet, as in Figure 5.

The rivers that carried the sediments to the Gulf also carried with them large quantities of organic material. The Thermal conditions within the geopressured zones were correct for the conversion of the organic material into methane - natural gas.

Methane is soluble in water; thus you would expect to find methane dissolved in the geopressured brines.

From Figure 6, one can see that at known reservoir conditions (press $\approx$15,000 Psi and temp 300-350°F) about 40 to 60 scf of gas would be dissolved in each barrel of water.

Thus the Geopressured Geothermal resource consists of the high pressure hot water and the dissolved methane.

From basic geologic work, the areas where potential resources might be found (i.e. the Geothermal Corridors) can be described as narrow bands parallel to the coast. Each of the bands corresponds to one of the depositional sequences (Frio Formation, Wilcox Formation, etc., Figure 7).

With a great deal of very careful geologic work potential resource areas or Geothermal Fairways can be located. These are areas that we think actually constitute a usable resource. Figure 8 shown the fairways for the Frio Formation only. From these sites we can choose an optimum reservoir. Figure 9.

It is found that as you move up the coast from Mexico to Louisiana the permeability of the sands increases (That's good), the temperature decreases (That's not good), and the amount of clean sands increases (That's good).

Since two out of three isn't bad the Brazoria Fairway was chosen for the test well site. The specific site is called the Austin Bayou Prospect.

The area around the Brazoria Test Well site, with the well marked at the (+) near the center of the fairway, is shown in Figure 10.

Predicted reservoir conditions for the Austin Bayou Prospect are:

Producing Internal	15,000 - 16,500 ft
Net Sand	700 ft
Temperature	300 - 325°F
Pressure	≈13,000 psi
Methane	40 - 50 scf/bbl
Salinity	30,000 - 60,000 ppm

The present state of the project is that the test well drilling should begin this week and within 90 to 120 days the well should be completed and then we will know a lot more about the Geopressured Geothermal resources as well testing proceeds.

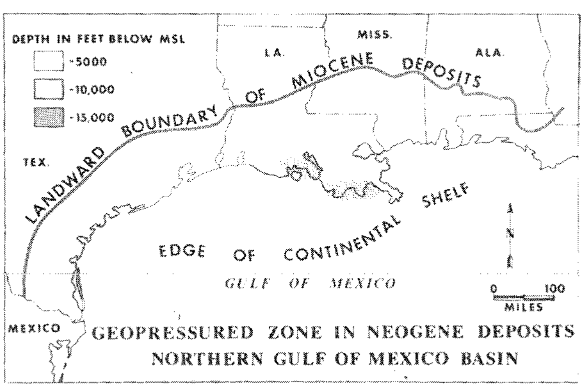

Figure 1

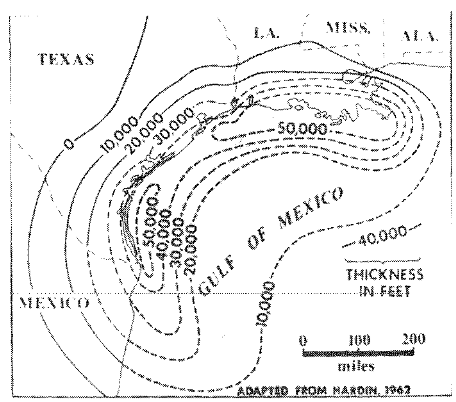

Figure 2

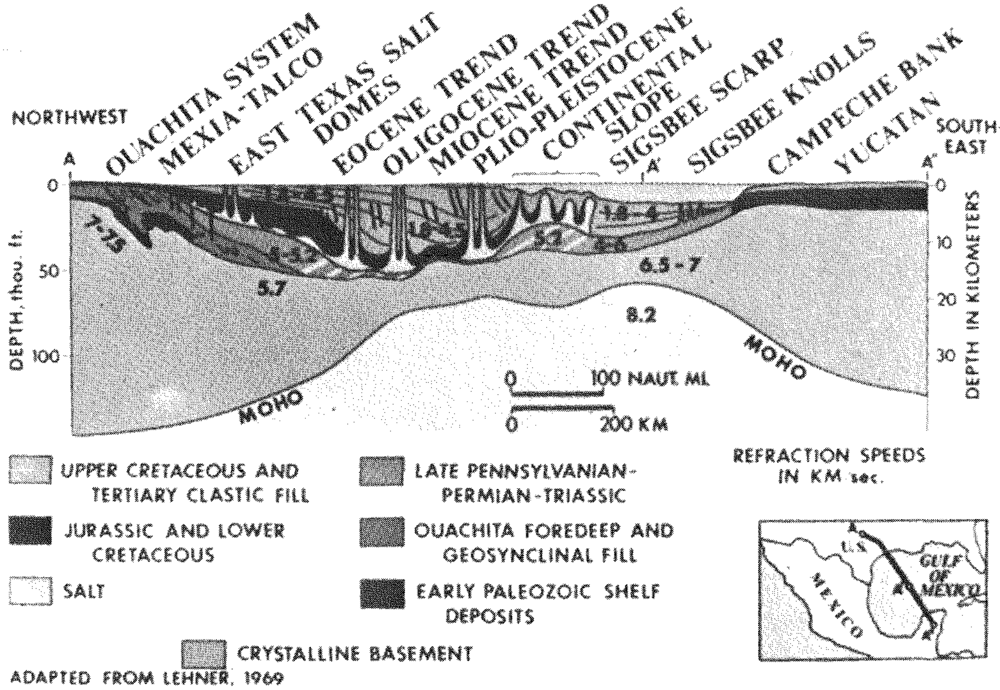

Figure 3

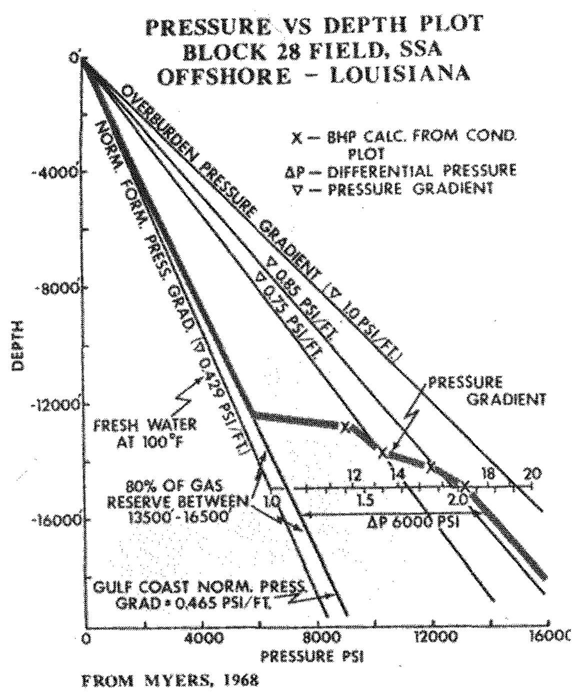

Figure 4

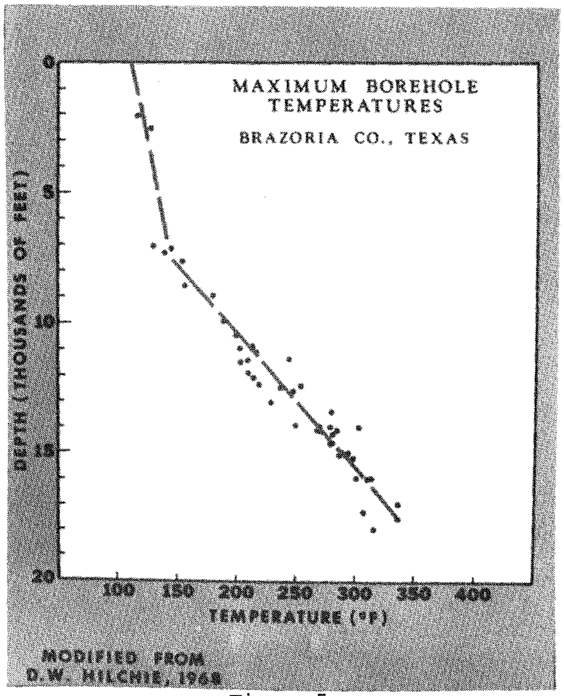

Figure 5

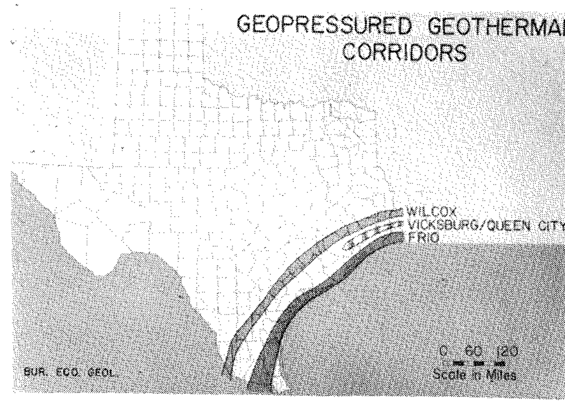

Figure 7

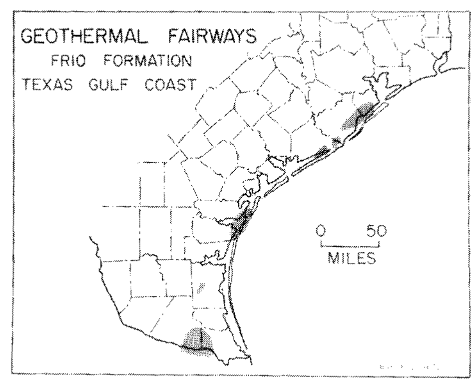

Figure 8

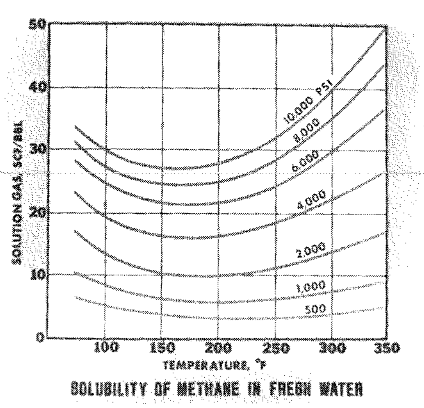

Figure 6

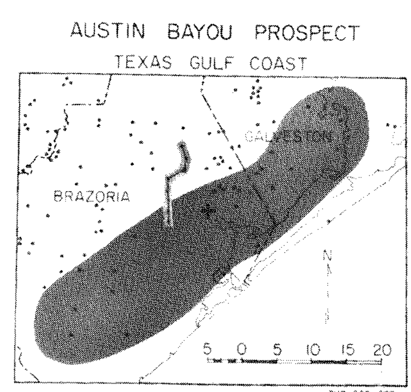

Figure 10

FRIO FORMATION
GEOTHERMAL FAIRWAYS

Figure 9

FIELD EVALUATION OF ROTARY

PHASE-SEPARATOR/EXPANDER ENGINE

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INTRODUCTION

The Biphase Energy Systems' rotary separator turbine is a total flow geothermal energy conversion device. It is designed specifically for use with high-salinity liquid-dominated geothermal resources. A two-phase nozzle is used to convert wellhead enthalpy to a high velocity steam-brine mixture. The system converts wellhead flow to separate clean steam and repressurized brine flows. In addition a brine driven liquid turbine direct drives an electrical generator. The process of flow modification and power generator are accomplished in the series operation of three major components: nozzle, rotary separator, and liquid turbine-generator. The nozzle provides the conversion of wellhead enthalpy to produce a high kinetic energy jet of steam and brine. This occurs as a nearly isentropic (85% efficient) expansion from wellhead to atmospheric pressure. The steam produced in the flash, atomizes and accelerates the liquid droplets in the nozzle. The resulting high velocity two-phase jet is directed to impinge on the inside of the rotary separator drum. This impingement causes the drum to rotate at nearly the nozzle exit velocity. The high centrifugal force field causes the liquid droplets to quickly migrate to the separator wall. A liquid film builds up on the wall until the liquid turbine inlet is immersed in the liquid. The liquid level stablizes when the flow into the turbine equals the nozzle liquid flowrate. The momentum of the liquid entering the turbine is converted to turbine output torque and pressure head as the liquid flows through a diffuser section in the turbine inlet.

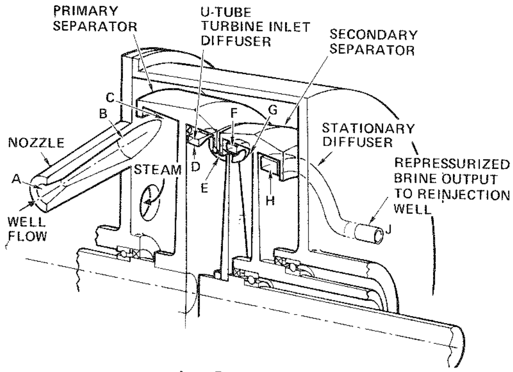
The liquid turbine has the configuration of a curved tube with an open end that scoops up the separated brine from the separator wall. The represurrized brine flow is carried by the curved tube to the hollow turbine shaft for discharge to the reinjection well. The turbine shaft is connected to direct drive the electrical generator.

A system of this type has been built and tested at a Brawley, California geothermal well operated by Union Oil. This test program was recently completed under Department of Energy (DOE) sponsorship. The final report (Ref. 1) is in the distribution process by DOE.

The first rotary separator field test with a high salinity resource (115,000 ppm TDS) demonstrated several important operating characteristics: 1) proper operation of the nozzle, separator and liquid turbine with 34% conversion of available enthalpy drop to brine output power, 2) clean steam production with 99.5% quality and 50 to 300 ppm solids content 3) high salinity tolerance with no significant scale deposition (0.02 in. in 120 hours), 4) self-brine pumping with discharge pressures up to 400 psig with 40 psig nozzle inlet pressures. These tests were conducted with the liquid turbine held stationary and all of the brine kinetic energy converted to pressure head.

PROGRAM GOALS

It is the purpose of the current program to be described, to extend the rotary separator field tests with the addition of a rotating liquid turbine. The turbine will direct-drive a generator for electric power production. Preliminary component calibration and system tests will be conducted at the Biphase Energy Systems test facility. The system will then be field tested at two Imperial Valley well sites for 1000 hours. The primary components of the separator turbine system are shown in Figure 1. The U-Tube turbine collects the flow from the primary separator, reverses the flow direction and expels the flow onto the secondary separator. Reversal of flow direction converts a portion of the brine kinetic energy to turbine output torque.



		A	B	C	D	E	F	G	H	J
PRESSURE	psia	80	14.7	14.7	14.7	28.5	14.7	14.7	14.7	80
LIQUID FLOWRATE	lbm/s	4.5	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
QUALITY	%	5	13.8	0	0.1	0	0	0	0.1	0
VELOCITY	ft/s	50	658	617	580	535a 225r	140a 190r	130	120	50
ROTATIONAL SPEED	rpm	–	–	–	4430	310t 2368	2368	993	0	0
COMPONENT EFFICIENCY	%	100	68	79	88	88	88 37	86	85	85
POWER	KW	61	41.5	32.8	29	25.6	22.2	1.5	1.3	1.1

a = ABSOLUTE VELOCITY, t = TURBINE VELOCITY, r = RELATIVE VELOCITY

FIG. 1 **ROTARY SEPARATOR TURBINE WITH U-TUBE LIQUID TURBINE**

The speed of the turbine is adjusted by load application so that the kinetic energy of the flow leaving the U-Tube is sufficient for conversion by the stationary diffuser to the required reinjection pressure. The secondary separator serves to transfer the flow with minimal losses from the U-Tube turbine discharge to the stationary diffuser. A separator turbine operating condition is summarized in Figure 1 also.

The performance calculation shows that for an equivalent wellhead condition of 80 psia with 5 percent steam, an isentropic expansion to atmospheric pressure produces 61 kW of available energy. The performance analysis considers the losses of the five separable components: nozzle, separator inlet, separator, liquid turbine inlet, and diffuser. The component performance analysis, (reference 1), results in the component efficiency values shown in Figure 1. The product of these five values is a 37 percent system efficiency which represents 22.2 kW shaft power output. The brine output at 80 psia represents an additional output of 1.1 kW in the form of saved reinjection pumping power. This system output represents only a portion of the output that would be obtained by a system designed to maximize resource utilization. Such a system would consist of a rotary separator liquid turbine with the addition of 1) a steam impulse wheel to convert the steam kinetic energy at the exit of the nozzle to an additional 20% output power and 2) a steam turbine and sub-atmospheric condenser to expand the steam to the lowest possible pressure. It is a program goal to provide performance projections for such an integrated system with tons of megawatt output. The immediate program goal is to obtain component and liquid turbine system performance to expand and verify the performance model to be used in the performance projects.

Component Tests

The first component verification has been completed with the calibration of the two-phase nozzle. The nozzle has a 25 in. overall length and 1.13 in. diameter throat. The calibration consists of a measuring the thrust produced by the nozzle exit flow over a range of steam and water inlet flowrates. Figure 2 shows the nozzle exit velocity which is calculated as the ratio of measured thrust to total input flowrate. The nozzle was tested

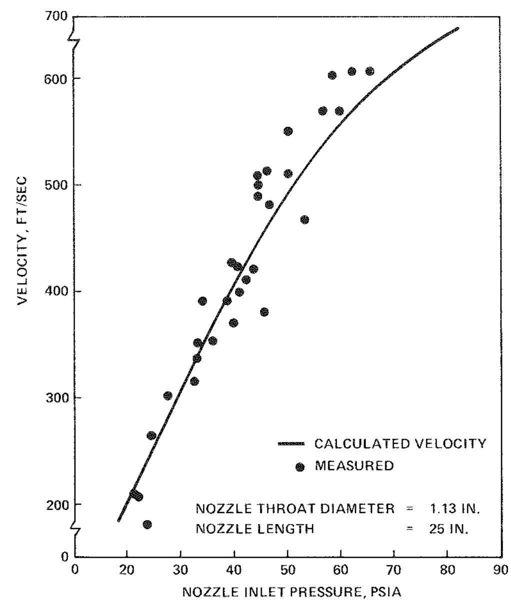


Fig. 2 MEASURED NOZZLE VELOCITY

over range of nozzle inlet pressures from 35 to 80 psia and steam qualities of 2 to 7 percent (of total input flowrate). The

150 to 600 ft/s. The nozzle calibration is complete with the conclusion that the nozzle performance is accurately predicted by the nozzle analysis which is represented by the solid line in Figure 2. The velocity prediction is based on a calculation (reference 2) with inputs of nozzle geometry and nozzle input pressure and steam quality.

With the completion of nozzle tests, the component tests will continue with separator and turbine inlet component tests. A constant-speed motor-driven rotary separator will be used to conduct flow visualization studies of flow patterns in the separator and turbine inlets. Kinetic energy transfer measurements between separator and turbine will be made. These tests will be conducted while the field test version of the rotary separator turbine is being fabricated.

MOBILE TEST SYSTEM

Upon completion of fabrication, the system will be installed for test in a semi-trailer van. Figure 3 schematically shows the test van installation. The primary components of the

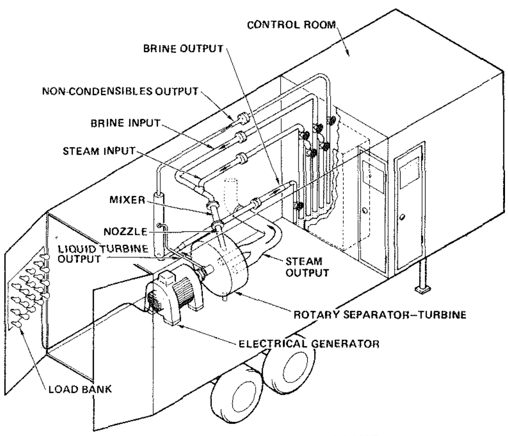


FIG. 3 **ROTARY SEPARATOR–TURBINE FIELD TEST SYSTEM**

rotary separator-turbine-generator system are shown in the test area of the van. A light bulb load bank will be used to visualize a portion of the electrical output power. The central console will separate the test and control areas and will contain the test control and instrumentation systems. The system design phase will be completed with the addition of piping and instrumentation details.

PERFORMANCE PREDICTIONS

As mentioned previously, the rotary separator turbine performance model will be used to extrapolate performance to higher power levels. A performance model has been prepared and will be refined as test data become available. The present model has been used to examine the effect of increasing wellhead pressure and separator diameter on system efficiency and output power. The power output for the low temperature resource summarized in Figure 1 is 22.1 kW corresponding to an 80 psia wellhead pressure. The lower set of three curves in Figure 4 shows the power level to increase from 23 to 62 kW with a nozzle pressure

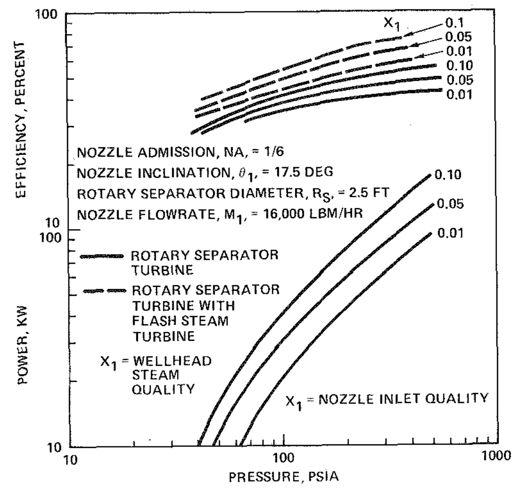


Fig. 4 **VARIATION OF OUTPUT POWER AND SYSTEM EFFICIENCY WITH WELLHEAD PRESSURE**

increase from 80 to 210 psia at 5 percent inlet steam quality. The middle set of three curves shows how the liquid turbine system efficiency varies with pressure and quality. The upper set of three curves shows the similar efficiency functional dependence for a liquid turbine system combined with both impulse steam wheel and steam expansion turbine to 2 psia. Both sets of efficiency curves show an approximate 5 percentage point increase with a pressure increase from 80 to 210 psia. This is primarily a result of improved nozzle efficiency with increased pressure and liquid atomization. The addition of the steam conversion components to the liquid turbine shows an efficiency increase from 44% to 60% at 210 psia. The efficiency is defined as the ratio of output power to the isentropically available power for expansion from wellhead to discharge pressure (14.7 psia for the liquid turbine and 2.0 psia for the steam turbine). Figure 5 shows the variation of output power from the liquid

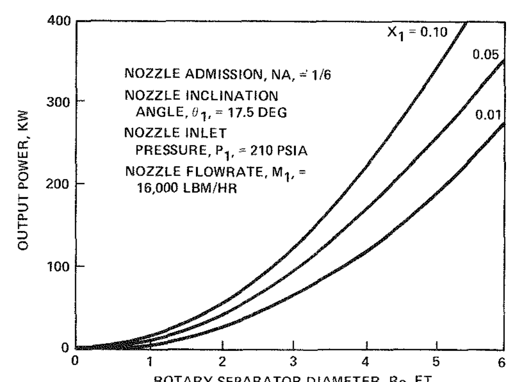


Fig. 5 **OUTPUT POWER VARIATION FOR ROTARY SEPARATOR LIQUID TURBINE WITH SEPARATOR DIAMETER**

turbine with a 210 psia wellhead pressure as a function of rotary separator diameter. The present design utilizes a 2.5 ft. diameter rotor. Figure 4 shows the output power to be 62 kW at 5% quality and 210 psia. Increasing the rotor diameter from 2.5 to 6 ft. increases the liquid turbine output from 62 to 368 kW as shown in Figure 5. Increasing the number of nozzles from one to the maximum (6) for full admission will increase the output power from 368 to 2208 kW. Adding full steam conversion will increase the total power to approximately 4.5 MW. There are four other independent separator turbine geometrical design parameters that provide power vs. efficiency trade-offs. These will be examined fully to find an optimum configuration. Another important consideration for a geothermal energy conversion system is to minimize the specific wellhead flow. This is defined as the ratio of wellhead flow to output power (lbm/hr/kW) The solid curves of Figure 6 shows how this parameter varies with wellhead pressure and

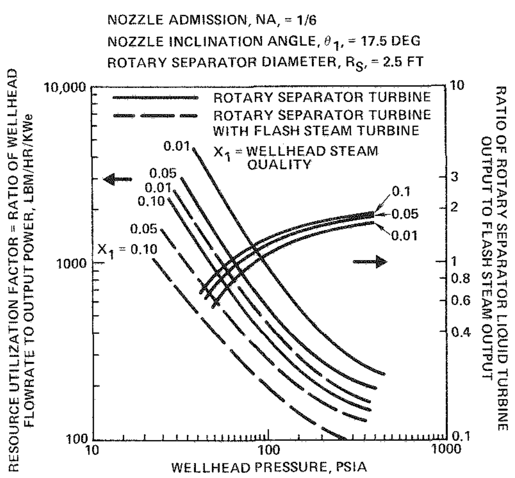


Fig. 6

VARIATION OF RESOURCE-UTILIZATION-FACTOR AND RATIO OF ROTARY SEPARATOR TURBINE TO FLASH STEAM OUTPUT WITH WELLHEAD PRESSURE AND QUALITY

quality for the liquid turbine system. The dashed curves show the increase in specific wellhead flow by increasing the output power with the addition of full steam energy conversion. The full system analysis to be performed will also include a cost estimate for the large multi-megawatt system. The specific cost characteristic ($ per kW) for the system will also be prepared for comparison with other types of conversion system.

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WASTE HEAT REJECTION FROM GEOTHERMAL POWER PLANTS

RP927-1

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PURPOSE OF STUDY The objectives of this study were (1) to identify the makeup water requirements for geothermal power production and (2) to develop analytical techniques and perform a comparative analysis of the waste heat rejection options for geothermal power plants to determine how water consumption may be reduced. The results of this study will be used to identify options that are best suited for geothermal waste heat rejection by region, resource type, and conversion technology.

In this study, consideration is given only to high-temperature subsurface water reservoirs under pressure (commonly called hydrothermal resources) which offer potential for the development of commercial power generation facilities. Most of the known hydrothermal resources are located in the western United States, where water resources are scarce, highly allocated, or influenced by regional institutional and legal considerations.

Wet, wet/dry, and dry cooling towers appear to be the principal cooling technologies for rejecting the waste heat from hydrothermal power plants. Comprehensive computer programs have been developed for this project for purposes of determining cooling water makeup requirements and energy production costs for the aforementioned cooling technologies. Parametric economic analyses have been performed for both flash steam and binary conversion processes for various combinations of resource temperatures, climatological types, hydrothermal "fuel costs", and cooling system makeup water costs.

PARAMETRIC ANALYSES PERFORMED Specifically, the parametric analyses performed for this study assumed the following range of values:

* Hydrothermal resource temperature: 150 C (300 F), 182 C (360 F), and 246 C (475 F)
* Hydrothermal power plant conversion process: Flash steam and binary
* Climatological type: High Mountain, Pacific Northwest, Basin and Range, and Hot Desert
* Cooling system type: Mechanical-draft wet towers and mechanical-draft direct dry/wet peaking towers
* Annual fixed-charge rate: 15 percent
* Hydrothermal "fuel cost": $\$0.50/10^6$ Btu and $\$1.00/10^6$ Btu
* Makeup water cost: $0.10/Kgal, $1.00/Kgal, and $2.50/Kgal (includes acquisition, transportation, treatment, and disposal costs)

By selectively analyzing various combinations of values for these parameters, it is possible to compare the busbar energy production costs and makeup water requirements for hydrothermal power plants equipped with alternative cooling tower systems under different site, design, and economic conditions.

The results of the analyses are presented in the form of curves representing relative busbar energy production costs as a function of percentage water use for a range of fuel and makeup water costs at the four sites. Zero percent water consumption represents a plant with dry cooling towers only, whereas 100 percent water consumption represents a plant with evaporative (wet) cooling towers only. The points between zero and 100 percent represent plants having different size combinations of dry and wet cooling towers, with a higher value of water consumption indicating a combination of a smaller dry tower with a larger wet tower. From such curves, the decision-maker can determine the incremental cost of reducing the water consumption of the cooling system, or, conversely, what cost would be incurred at a site if only a certain quantity of water were available, thereby requiring the supplemental use of dry cooling systems.

INFORMATION OBTAINABLE FROM COMPUTER PROGRAMS
The computer programs which were developed to economically optimize and evaluate mechanical-draft evaporative and direct dry/wet peaking cooling tower systems provide the following information for each combination of resource temperature, conversion process, climatic condition, fuel cost, fixed-charge rate, and makeup water cost considered:

* Gross annual base generation and auxiliary energy requirements
* Annual makeup water requirements
* Annual plant capital and operating costs
* Annual hydrothermal "fuel" and operating costs
* Annual makeup water and operating costs
* Total annual capital and operating costs
* Busbar energy production costs
* Busbar component cost breakdown
* Summary of pertinent cooling tower and condenser design data
* Cost breakdown for cooling tower, condenser, circulating water facilities, controls, engineering and contingencies, interest during construction, and conversion plant
* Annual turbine operation profile
* Annual plant generation profile
* Distribution of heat load between wet and dry towers for the dry/wet peaking tower

RESULTS OF STUDY The results of the parametric analyses presented in this report represent a wide range of variables and assumptions which affect the performance and economics of hydrothermal power plants. However, since geothermal energy is still in the development stage, necessary data are not yet available for many aspects of the power plant design, e.g. the performance of binary turbine-generators for many resource conditions.

The binary turbine data used in the analyses performed are based upon the Elliott turbine design for a 182 C (360 F) resource and therefore do not represent optimum hydrocarbon working fluid choices or turbine designs for either 150 C (300 F) or 246 C (475 F) resources. By comparison, the flash steam turbine data used in the analyses are based upon well-established turbine performance estimating methods and therefore are considered to be valid for all three temperatures investigated.

Several conclusions may be drawn based upon the range of values analyzed in the parametric analyses performed in this study:

* Busbar energy production costs are very sensitive to hydrothermal resource temperature and hydrothermal "fuel cost" and less sensitive to climatologial type and makeup water cost. All other parameters remaining constant, busbar energy production costs for 150 C (300 F) resources are generally on the order of 80 percent higher than for 246 C (475 F) resources. Likewise, an increase in "fuel cost" from $0.50 to $1.00/10^6 Btu will result in an increase in busbar costs on the order of 50 percent. However, an increase in water cost from $0.10 to $2.50/Kgal will result in an increase in busbar costs of only about 15 percent. The differences in busbar costs for the four sites are typically on the order of 5 percent.
* Turbine-generator design significantly determines the overall plant performance and economics of both the binary and flash steam conversion systems. Direct comparisons between binary and flash steam systems for 150 C (300 F) and 246 C (475 F) resources were not possible in this study since optimum binary fluid choices and turbine designs are not yet available.
* Analyses indicate that binary systems yield slightly lower busbar energy production costs than flash steam systems for the 182 C (360 F) resource temperature, although makeup water requirements are higher than for flash steam systems. Higher heat rejection for the binary system relative to the flash system accounts for the higher makeup water requirements.
* No computer analyses were performed for the radial hydrocarbon turbine

design for the binary conversion process (turbine performance data were not available in time for this study). An examination of the radial turbine performance characteristics which were furnished by a manufacturer indicates that the busbar energy production cost and cooling system makeup water requirements should not differ significantly from those of the axial hydrocarbon turbine unless there are significant differences in capital or operating costs between the two types of turbines.

* On the basis of the turbine performance data available for this study, cooling system makeup water requirements for evaporative cooling towers serving flash steam systems are approximately 24-27 percent higher for 150 C (300 F) resources than for 182 C (360 F) resources, and approximately 29-30 percent lower for 246 C (475 F) resources than for 182 C (360 F) resources. Makeup water requirements for evaporative cooling systems serving binary systems are approximately 17-21 percent higher than for flash steam systems for 182 C (360 F) resource temperatures.

* For the range of fuel and makeup water costs considered, an all-dry cooling tower system does not appear to be economically competitive with an evaporative cooling tower system. However, the addition of a relatively small evaporative peaking tower to the dry tower (such as 95 percent dry/5 percent wet) will substantially reduce the busbar cost penalty incurred by an all-dry system. As the cost of makeup water increases, the relative difference in busbar cost between an all-dry or a dry/wet peaking tower and an evaporative tower decreases significantly.

* For low water costs ($0.10/Kgal), the penalty in busbar cost for saving approximately 60 percent water by use of a dry/wet peaking cooling tower is on the order of 7-15 percent for non-desert sites and 9-25 percent for desert sites. However, for higher water costs ($2.50/Kgal), the penalty decreases to approximately 1-4 percent for non-desert sites and 2-10 percent for desert sites. The economic penalty for saving more water increases as additional dry cooling is used. Therefore, the use of dry/wet peaking towers may be feasible for hydrothermal power plants under certain site, plant design, and economic conditions as well as social and environmental constraints.

* Busbar energy production costs and cooling system makeup water requirements as estimated in this study for given plant design and economic constraints do not vary significantly for non-desert sites. However, busbar costs are approximately 2-6 percent higher and makeup water requirements are approximately 6-17 percent higher for desert sites.

* Several methods for accounting for costs associated with loss of generating capacity were considered in this study. Busbar energy production costs are slightly lower for the method which does not penalize for loss of capacity during operation at high ambient temperature conditions than for the other methods. However, typical differences in cost for these alternative methods are on the order of a few percent.

* Direct dry towers resulted in lower busbar energy production costs than indirect dry towers for the generating units with the sizes evaluated in this report. Differences in cost are typically on the order of a few percent of the total busbar cost, so that this conclusion could change if relative capital costs of the two systems are different from those assumed.

* For study purposes, the design back pressure value does not significantly affect the relative estimated busbar energy production cost or cooling system makeup water requirements. In the actual design of a hydrothermal power plant, however, the design back pressure is an important consideration.

Recommendations for Subsequent Studies

In addition to the need for binary turbine-generation performance data for a range of hydrothermal resource temperatures, our analyses indicate that the following studies are warranted:

* Analyses of alternative hydrocarbon turbine designs should be performed before any major decision is made regarding either the selection of a hydrocarbon turbine or the selection of one conversion process over another.

* The actual operation of hydrothermal power plants in conjunction with other conventional power plants on the utility grid should be evaluated. Forced outage rate, planned outage for scheduled maintenance, and summer and winter capacity of the hydrothermal plant should be investigated with respect to operating economics.

* Because of the high fuel costs and cooling system auxiliary energy requirements associated with hydrothermal plants, natural-draft cool ing systems may be more economical than mechanical-draft systems at many locations and should therefore be evaluated in subsequent studies. The choice between mechanical-draft and natural-draft cooling towers is usually based on economics, although in some instances environmental considerations could favor the use of natural-draft towers.

Accuracy of Results The accuracy with which cost estimates can be made for new energy conversion technologies is directly related to the history and experience of the industries developing the technologies. In the case of hydrothermal power plants, capital cost estimates are subject to inaccuracies resulting from a lack of cost trends, which can be established only after several power plants have been designed and constructed. Moreover, site-specific costs due to local labor and materials cost differences or physical site conditions will also markedly affect plant costs for any actual installation.

The accuracy with which the computer programs developed for this study simulate actual power plant performance is limited primarily by the accuracy or applicability of the turbine performance data, climatological data, and capital cost data. Estimates of makeup water requirements are based upon rigorous procedures adopted by the Cooling Tower Institute and therefore are limited primarily by the accuracy or applicability of the turbine performance and climatological data. Therefore, as data are refined, the accuracy of estimating energy production costs and makeup water requirements can also be refined.

CHARACTERIZATION OF MAGMA 11.2 MWe EAST MESA BINARY POWER PLANT

(RP1195-3)

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The Objective of this Project is to determine the operating conditions and performance of the Magma East Mesa 11.2 MWe Binary Power Plant and the power plant component systems. Both overall gross plant performance and operating characteristics of specific equipment will be determined. Variables such as brine and isobutane flow rate and thermodynamic conditions and gross and net electrical output will aid in establishing plant efficiency. Variables such as heat transfer and pressure drop in the heaters and boilers will aid in the performance evaluation and scale-up of other similar geothermal power plants. This power plant design is a rather sophisticated combination of a power plant with a process plant, superimposed with a complex cooling water system. Such a combination results in a series of energy and flow circuits that are highly coupled, each having its own unique features.

The Power Plant utilizes novel turbines which perhaps have not been operated directly with this type of hydrocarbons used as the working fluids, i.e., isobutane and propane. The turbine is a noncondensing extraction type with the isobutane coming out in a dry superheated state. The extraction gas flow is used to drive a turbine which drives a boiler feed pump. The main turbine will drive a synchronous generator and the other an induction load generator. The performance of both turbines must be accurately measured under defined operating conditions.

The prime energy supply scheme in the plant consists of uniquely-designed heat exchangers which transfer heat from the brine to the isobutane and the propane streams. Unlike conventional fossil fuel boilers, the performance, sensitivity and efficiency of these heat exchangers have not been defined on a common basis. However, operating experience from the process plants can be utilized in the analysis of the heat exchangers cycle.

Design Features. The power plant consists of several separate flow circuits--brine, isobutane, propane, cooling water--which "interact" through heat transfer from one stream to the other in heat exchangers. The brine stream undergoes cooling through a series of heat transfer processes, first to isobutane superheaters and boilers, then propane superheater and boiler and finally, liquid isobutane heaters. At full load conditions, the brine undergoes a cooling range from 360°F to 180°F and a pressure drop from 270 psia to 115 psia before being rejected to the wells. The isobutane which exits the turbine in dry conditions enters the "recuperator" which is used to desuperheat the isobutane before entering the condenser by heating propane in the dual circuit. The reheat circuit of the isobutane consists of six heat exchangers with a pair of boiler and superheater heat exchangers in parallel as shown in Figure 1.

The propane circuit is designed to provide 2.3 MWe of the total output. The propane is being heated and boiled first, by the isobutane coming off the turbine in the recuperator and then further superheated by the brine stream coming off the isobutane boilers as shown in Figure 2.

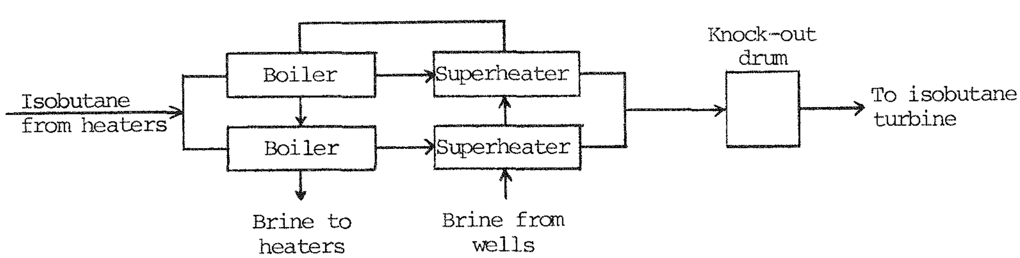

Figure 1 Isobutane Boiling Superheating Circuit.

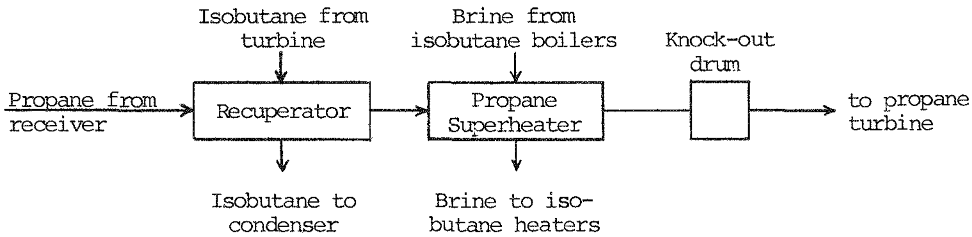

Figure 2 Propane Heating Circuit.

All the heaters and boilers operate essentially under once-through conditions. The cooling water from a spray pond system flows through the tube side of the propane condenser and then splits into two parallel streams and flows through two isobutane condensers. The above heat-exchanging loop necessitates additional components to assure proper operations during startup and shutdown. These components are various bypass lines, receivers, headers and knock-out drums. These components, although not affecting the energy transfer, will affect the flow balance of the circuits.

Performance Features. This power plant must be operated to minimize any operational problems. The brine circuit might be subjected to fluctuations in brine flow rate, temperature, pressure, TDS (Total Dissolved Solids), pH and noncondensibles content. These fluctuations will affect the potential for possible fouling and scaling in the heat exchangers. In the heat exchangers, the hydrocarbon is undergoing a nonlinear enthalpy absorption process by being heated, boiled and superheated. The process in the isobutane recuperator is highly sensitive to the flow conditions since the heat transfer process consists of condensing in the shell side and boiling in the tube side--similar to feed-effluent heat exchangers utilized in process plants. The geothermal brine undergoes essentially a linear enthalpy release process, but changes in brine physical properties and its pressure-temperature conditions will affect the linearity of the brine enthalpy release process. The brine pressure vs. temperature conditions and the flow velocity and in-tube surface temperature will determine the fouling potential. As the temperature and pressure of the brine decrease along its flow path, conditions for flashing must be avoided. Flashing will result in release of gases, possible carbonate fouling and increase in pressure drop and the reduction of heat transfer coefficient. On the other side, a combination of low velocities and tube temperature might result in the deposit of, possibly , silica solids in the tube. The effect on heat transfer is similar to the effect from flashing. Part-load operation and startup and shutdown conditions are most susceptible to operational problems. Furthermore, the startup and shutdown requirements impose piping and valving design which increases the possibility of leakages. The flow in some of the heat exchangers is two-phase liquid vapor flow. Fluctuation in flow conditions will affect the pressure drop and thus the in-plant auxiliary power demand.

Test Objectives. The test objectives in the performance analysis of the Magma Power Plant are thus both specific and general. They are specific in that the performance of this power plant will be defined and measured. Secondly, there is the interest in acquisition of data that will enable generalization of the performance and its extrapolation to other operating conditions and equipment size. The gross plant performance variables under both full-load and part-load conditions are listed as:

* Isobutane and propane turbo-generator electrical output
* Flow and thermodynamic conditions at inlet and outlet of turbines
* Brine flow and thermodynamic conditions at the inlet and exit of the power plant
* Cooling water flow and temperature-pressure conditions at the inlet and exit of the plant
* Power generated by isobutane feedpump turbine
* Electrical power required by isobutane booster pumps
* Electrical power required by propane condensate and boiler feedpumps

The more detailed equipment performance variables are:

* Heat transfer coefficient of isobutane, brine and overall in the isobutane heat exchangers
* Friction pressure drop coefficients of brine and isobutane in the heat exchangers

* Same variables as above in the propane boiler superheater

* Heat transfer coefficient of isobutane, water and overall in the isobutane condenser

* Heat transfer coefficient of propane, water and overall in the propane condenser

* Heat transfer coefficient of isobutane, propane and overall in the recuperator

* Friction pressure drop coefficients of propane, isobutane and water in the condensers and the recuperator

The above objectives require the acquisition of a large amount of plant data. These data consist of usual power and process plant information on electrical power, shaft torque, pressure, temperature and flow rates.

In addition, it is important to analyze the startup and shutdown conditions and the plant controllability. Under part-load conditions, the propane circuit may be shut down and only the isobutane operated. Or, both circuits may be in operation but derated for part-load conditions. Conditions of startup and shutdown are most susceptible to the deposition of fouling in the heat exchanger and piping components. Plant controllability is an important aspect of the performance analysis, since fluctuations may be an inherent feature of the brine circuit. Because of the strong interactions among the plant components, such fluctuations affect the performance in a complex mechanism which includes inherent two-phase flow instabilities. It is thus important to assure that plant control does not lead to unstable operating conditions. The time constant of the changes from full-load to part-load conditions is an important variable of the plant control.

Strategy of Testing. In the case of acquisition of a large amount of interacting plant data, there is the inclination to use statistical methods to devise the strategy of experimentation and the analysis of the data. This may be of some advantage when data are random and no physical mechanism exists to clarify the relationship among data points. In this project, the interaction among measured variables is not random but is based on physical phenomena which are described by the principles of heat transfer and fluid flow. Statistical methods will be helpful in discerning random fluctuations and electronic equipment line noise and drift effects. However, some fluctuations in measured variables such as temperature can be due to system response and long time constant. Preliminary calculations showed that because of the size of the heat exchanger, the system response time constant can be as long as 150 seconds. This is much longer than the feedback control system time constant which is on the order of seconds. This discrepancy may result in system fluctuations which have no aspect of statistical mechanism. Proper data acquisition and reduction must recognize the physical mechanism as a cause for data fluctuation. It is possible to model the performance of the plant equipment which will describe the interaction among plant variables on the basis of these physical phenomena.

The process phenomena of this plant incorporate two phase as well as single phase flow. There exists a vast literature on two-phase, liquid vapor flow in tubes. PFR's experience from process plant heat transfer will be utilized as well as existing information on turbine design, condensers and boiler design and reported literature on the onset of fouling conditions.

The following considerations will be incorporated in the acquisition of data during testing:

* Types of data. The measurement will consist primarily of temperatures, pressures, and flow rates as indicative of the process conditions. Some data will also be taken of the physical and chemical condition of the geothermal brine and cooling water. Power generation will be measured as electrical output, shaft torque and voltage and amperage drawn by electric motors.

* The number and density of data points. In many cases, the values of some variables may be back-calculated from measurement of other variables. We will examine and establish the redundancy in measurement required for reliable data acquisition. In a heat balance around a heat exchanger, it is desirable to check the heat load through measurements of both tube side and shell side conditions. This will establish the reliability of the data and in detecting secondary effects such as heat losses or flow leakage. Redundancy in pressure measurement will also indicate the friction pressure losses in the lines and valves. On the other hand, measurement of conditions around the turbines may require the utilization of manufacturers performance curve for a check on the data.

* Accuracy of instruments. The specific accuracy of the instruments is determined by the range of variation in the variable measured, its sensitivity and effect on the overall performance, and the purpose of the specific measurement. The relative accuracy of pressure measuring instrument of high pressure

stream is different from the accuracy of temperature measurements utilized for heat balance over a heat exchanger with small temperature drop. It is important to provide the capability of frequent calibration of the instrument. Measurements should be taken with instruments whose calibration is periodically checked.

* Location of instruments. The physical location of the measuring device must be free from local disturbances which will affect the results. Flow regime, stream mixing, heat loss and fouling are some of the considerations incorporated in determining the optimal instrument location.

* Repeatability and stability. Meaningful measurements must be reproduceable and taken when the operation is in steady state. The operating conditions will be checked to assure typical and stable measured data.

* Data acquisition system. The acquisition of many data points must be done efficiently and must be free of operator errors and time scale shifts. The system should be able to store the data and provide the capability for "on the spot" checks on the quality of the measured data point. An electronic data acquisition system coupled with a minicomputer is being considered.

Power Plant Modeling. The greatest utility of this acquired data will be provided through an energy and material balance. This balance can be performed over the entire plant and also along the path of the energy transfer, producing and consuming flow circuits. A "closed" energy and flow balance is the best check on the consistency and accuracy of the test data. A balance thus achieved enables the evaluation of plant performance free from ambiguities and uncertainties.

The complexity of the flow and energy circuits of this plant necessitates the use of a computer model to handle the measured data. Furthermore, since the objectives also include the analysis of the performance of the individual plant equipment, such a program may be imperative.

The computer model of the power plant will achieve the following objectives:

* Analyze all the data simultaneously

* Provide overall plant performance at any operating conditions

* Provide mass, heat and energy balance over each component of the plant

* Calculate heat transfer and pressure drop coefficient for each heater, boiler and condenser in the plant

* Estimate the rate of fouling deposition (if occurring) in the heat exchangers and the lines

* Simulate other plants of similar design but different size and operating conditions

Plant Instrumentation. In reviewing the plant's P & ID drawings, it was evident that the plant designers have provided ample instrumentation for monitoring the operation of the plant. Some of the data is recorded in the control room and other data must be read manually at the instrument location. The data recorded in the control room include all the control signals as well as the monitoring of key plant variables. These data must be supplemented by the reading of other field instruments.

The data acquired through automatic recording in the control room are insufficient for a complete mass and energy balance over all the flow circuits in the plant. The control room data acquisition is primarily intended for control purposes, and only indirectly as a measure for plant performance analysis. The direct read-out field instruments consist mainly of pressure and temperature measuring devices. As such, the accuracy of the devices, especially the temperature sensors, must be commensurate with required accuracy in the energy balance. For example, the accuracy of the sensor reading the inlet and outlet temperatures of the isobutane in the recuperator is estimated to be ±2.5°F. The full design temperature drop over the recuperator is estimated to be 74°F. Thus, the accuracy of the heat balance over the recuperator cannot be better than ±7%. Such accuracy may be insufficient for reliable heat balance, especially when compounded with inaccuracies in the flow and pressure measurements. The P & ID of the entire plant will be reviewed to establish the need for additional instruments for improved accuracy.

In conclusion, this program will provide information on both overall and detail performance of the Magma 11.2 MWe East Mesa Power Plant. This will greatly enhance the state of the art of geothermal power plants and further the cause of the geothermal energy in general.

GEOTHERMAL POWER PLANT COMMITMENTS IN CALIFORNIA

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Introduction This paper presents my personal views on the status of geothermal power plant commitments in California and the status of State efforts to encourage commitments to build such plants. I am also presenting my analysis of some measures that have been proposed for the purpose of stimulating power plant commitments. Because this particular gathering of geothermal specialists focuses on the issues confronting power plant projects and is organized by the electric utilities' industry-wide geothermal research and development program, I want this group to be aware of the views I am presenting within the Energy Commission and I want to use this gathering to increase my understanding of industry views on risks and incentives for geothermal power plant commitments.

The other participants in this session will present more detailed information on specific power plant projects, most of them in California. Therefore, I will limit my status report to an overview of the geothermal development situation in California, a summary of projections I have made of possible accelerated expansion of geothermal power production in California, a survey of the status of the specific projects that could contribute to this expansion, and a report on State of California actions relevant to geothermal power plant commitments. Finally, I will discuss possible actions to stimulate power plant commitments through the State's role in regulating electric utilities.

Status and List of Key Actions The estimated geothermal energy resource base in California is very large, estimated at 20,000 MW of electrical generating capacity for 30 years. An even larger resource base exists for purposes of direct heat (non-electric) applications, but is not of concern for purposes of this paper on power plant commitments. However, only about 2,000 MW of this resource base has been established through actual drilling and testing of wells. The resource established by deep drilling consists of the dry steam reservoir at The Geysers and the hot water resources found in quantity at at least four anomalies in the Imperial Valley. The present basis for geothermal power plant commitments in California is at these two locations. Successful demonstration of electric power plants utilizing moderate temperature geothermal resources, such as are found at Heber and East Mesa in the Imperial Valley, would make power generation from the hot water geothermal resources expected to be found elsewhere in the state appear as a very attractive option. In that event the stimulus to explore by deep drilling to find the additional resources expected to be present would be very strong. Whether these additional resources turn out to amount to 5,000 MW capacity or 30,000 MW capacity the immediate action requirement remains the same, namely, to demonstrate the feasibility of hot water geothermal power generation.

The key action items for geothermal development in California are as follows: first and foremost is the need to build three 50 MW hot water geothermal power plants to test resources and technology for this form of power generation and to establish the basis for a rapid expansion of goethermal power generation if these tests are successful. A second key action is final regulatory resolution of the major issues confronting expansion of geothermal energy development following the first successful hot water power plants in the Imperial Valley. A third action, directed primarily at The Geysers area where power conversion technology is already established as economically attractive, is the abatement of hydrogen sulfide emissions from power plants and steam fields in order to eliminate an air quality problem already existing in that area. Fourth, rapid expansion at The Geysers can be achieved only if the hydrogen sulfide problem is solved as indicated in the preceding point and if plans for acceptable expansion are formulated at an early date. Fifth, and finally, federal leasing of land for potential geothermal development is required at an early date in order that new resources will be discovered and proved soon enough to take immediate advantage of success in operation of the first hot water geothermal power plants.

Before focusing on the status and possible expansion of geothermal development at The Geysers and in Imperial Valley, I will summarize the situation elsewhere in California. Development elsewhere depends in large measure on factors associated with two of the actions named above: (1) successful demonstration of the conversion of moderate temperature hot water geothermal resources to electricity as a stimulus to finding and developing the resources expected to be found elsewhere in the state; and (2) leasing of federal land for geothermal exploration and, where exploration is successful, development of geothermal fields and power plants. The resources estimated to be available in the other parts of the state and estimated to be capable of conversion to electricity could amount to nearly 13,000 MW, according to the USGS in 1975 (Circular 726). Estimates compiled by the Jet Propulsion Laboratory (JPL) for the California Energy Commission and the U.S. Department of Energy are somewhat lower due to industry skepticism regarding the higher estimates of the USGS published in 1975. In working out schedules for possible geothermal development outside of The Geysers and the Imperial Valley I have used the following resource estimates compiled in 1977 by JPL: Coso Hot Springs 2,000 MW; Mono-Long Valley 2,000 MW; and Northeastern California (Lassen, Wendel-Amedee, Surprise Valley, Honey Lake, and other geothermal resources) 4,500 MW. These are substantial downward revisions from some of the estimates in Circular 726 issued by the USGS in 1975. However, new estimates are being prepared by USGS for release in 1979. The new USGS report is expected to reduce the resource estimates for the areas named above to levels lower than those now in the report by JPL. As far as power plant commitments are concerned, these other areas are not yet ready for commercial-scale power plant commitments. Despite disagreement on the size of the potential resource, there is widespread agreement that wells must be drilled and flow tested before plans can be made for power plants in these other geothermal resource areas.

Projections of Possible Expansion Table 1 summarizes a possible rapid expansion of geothermal electricity generation from The Geysers. This schedule proposed by staff of the California Energy Commission represents some acceleration of the schedule planned by Pacific Gas and Electric Company (PGandE) and requires compliance with present plans for scheduling the first power plants constructed by other utilities in The Geysers area. Critical to achieving this accelerated schedule is the abatement of hydrogen sulfide emissions, the achievement of a one-year geothermal power plant siting procedure as now being undertaken by the Energy Commission, and the proof by deep drilling that the dry steam reservoir will support more than the 2,000 MW of electric power production now confidently expected at The Geysers.

Table 2 presents two possible schedules for development of electric power generating capacity in the Imperial Valley. Rapid expansion in the Imperial Valley depends on (1) immediate commitments to build power plants (at least one or two of them at the 50 MW scale); (2) early success in operation of the first power plants; and (3) early and rapid permits and decisions to build a second round of plants. Such vigorous and successful development would lead to 200 MW in 1982, 400 MW in 1985 and 800 MW in 1987. A cautious, but determined, effort to achieve geothermal electrical generating capacity in the Imperial Valley would build more gradually to 100 MW in 1982, 150 MW in 1985 and 250 MW in 1987. This slower pace, as compared to the above situation, would result from fewer and slower commitments to build the first round of 50 MW plants and from more limited success of those plants leading to delays in commitments to build the second round.

The geothermal power plant commitments most critical for California are the commitments to build the first few plants operating on hot water (or brine) resources. Table 3 lists projects that could lead to 50 MW hot water power plants in the 1981 to 1983 period - i.e., that could become part of the first round of such plants. A "first round" plant is one that is built without the benefit of operating experience with another similar 50 MW plant. I have indicated in Table 3 the status of these projects as I understand them. Additional information on some of them is being presented in papers by the principal parties themselves.

State of California Actions First, I will mention actions by the State that can support acceptable expansion of power production from The Geysers dry steam field. Briefly, the State role is emerging in three areas: hydrogen sulfide emission control, data and analysis to support local land use decisions on expansion of The Geysers geothermal development in the four affected counties, and implementation of accelerated power siting procedures for geothermal power plants. In addition, pending legislation could increase the direct State role by expanding the authority of the Division of Oil and Gas to become lead agency for environmental assessment of exploratory drilling projects.

To stimulate commitments to build the first hot water power plants - plants that would become the basis for geothermal power production above the 2,000 MW (or perhaps somewhat more) expected from dry steam at The Geysers - a number of State actions have been contemplated. The action considered in most detail so far is creation of an "Energy Development Authority" with funds adequate to provide substantial support to one or more power plant projects, possibly in conjunction with the Federal loan guarantee program. However, the present constraints imposed by response to the passage of the property tax reduction initiative in California make it unlikely that State funds will be available for new energy programs. Other means of stimulating geothermal power plant commitments are receiving more attention within State agencies. I personally am emphasizing action by the Public Utilities Commission (PUC) to approve exceptional R&D or electricity purchase expenses associated with the first two to four commercial-size hot water geothermal power plants. I am giving equal emphasis to PUC assurance that utilities can recover capital costs with adequate return on investment from funds committed to construct the first round of these plants, regardless of the performance of the plant and reservoir. My proposals for PUC actions that could stimulate commitments to build the first round of hot water geothermal power plants are presented in a subsequent paper in these proceedings. (See "Geothermal Development: Risks and Incentives" in the section of these proceedings dealing with the resource risks associated with geothermal development.)

State actions directed at encouraging second round power plant commitments are described in a third paper, "Environmental Issues," presented in the section of these proceedings dealing with environmental risks. In brief, the State actions to facilitate expansion of those geothermal power plants whose technology and economics are established as competitive center on implementation of a timely power plant siting procedure with provision for resolution of critical environmental issues as early as is practical. The Energy Commission's project with Imperial County is described in my Environmental Issues paper as an example of action to facilitate expansion of development after the first round of plants in the Imperial Valley.

Table 1
ACCELERATED SCHEDULE FOR GEYSERS EXPANSION

Year	PG&E Units (dry steam)	Size (MW)	Other Units	Size (MW)	Cumulative (MW)
1978	12, 15	161			663
1979	13, 14	245			908
1980					
1981	16, 17	220	NCPA/Shell	110	1238
1982	18, 19	220	NCPA/RFL	66	1524
1983	20, 21	220	DWR Bottle Rock	55	1799
1984	22, 23	220	DWR South Geysers	55	2074
1985	24, 25	220	SMUD No. 1	110	2404
1986			SMUD No. 2 (110) DWR Newfield (55) Hot Water No. 1 (50)	215	2619
1987			Hot Water No. 2,3	100	2719
1988			Hot Water No. 4,5,6	150	2869
1989			Hot Water No. 7,8,9,10	200	3069
1990			Hot Water No. 11,12,13,14	200	3269

Notes:

1. This schedule is proposed by the Energy Commission's Geothermal Energy Office as an acceleration of current utility plans. Changes from the PG&E resource plan are as follows:
   - Units 18, 19 on line in 1982 instead of 1983
   - Units 20, 21 on line in 1983 instead of 1984
   - Units 22, 23 on line in 1984 instead of 1985 and 1986
   - Units 24, 25 on line in 1985 instead of 1987 and 1988

2. The following regulatory and construction timetable will contribute to achieving the accelerated schedule:
   - 1 year to obtain permit for exploratory drilling
   - 2 years to drill and prove a resource
   - 1 year to permit field and power plant development
   - 2 years to bring plant and field into operation

Although past experiences has not been this favorable, such a timetable is possible and would result in power on line 6 years after an application to drill an exploratory well and only 3 years after utility commitment to build a power plant.

3. The accelerated schedule requires proof of additional dry steam resources to be obtained as follows:

Year	Cumulative Proof (MW)	Year	Cumulative Proof (MW)
1978	1300	1981	2100
1979	1550	1982	2400
1980	1800	1983	2600

At the end of 1977 the cumulative proof of dry steam resources amounted to 1200 MW. About 2000 MW are confidently expected. Success in drilling beyond the present dry steam field could lead to the 2600 MW used in this schedule.

Table 2

TWO POSSIBLE SCHEDULES FOR GEOTHERMAL
POWER PRODUCTION IN IMPERIAL VALLEY
(units are capacity in MWe)

Calendar Year	Case I: Cautious Determined Effort				Case II: Vigorous Successful Development			
	Activity During Year			Cumulative Power-on-line	Activity During Year			Cumulative Power-on-line
	Apply	Construct	Operate		Apply	Construct	Operate	
1978	50	0	0	0	100	0	0	0
1979	50	50	0	0	100	100	0	0
1980	50	50	0	0	0	100	0	0
1981	0	50	50	50	100	0	100	100
1982	0	0	50	100	100	100	100	200
1983	50	0	50	150	200	100	0	200
1984	50	50	0	150	200	200	100	300
1985	—	50	0	150	—	200	100	400
1986	—	—	50	200	—	—	200	600
1987	—	—	50	250	—	—	200	800

Notes:

1. "Apply" means application for permit to construct power plant and field.

2. "Construct" means firm financial commitment to build power plant and field.

3. "Operate" means begin production of electricity.

4. Timeline assumptions: (a) assumes resource already proved or proved during same year as power plant permit application is considered; (b) one year to issue permit to construct; (c) plant begins operation two years after firm commitment is made to construct plant and field.

Table 3

POSSIBLE "FIRST ROUND" HOT WATER GEOTHERMAL
POWER PLANT COMMITMENTS: STATUS JUNE 1978

				Resource Status			Power Plant Status	
Principal Participants	Location	Size	Type	Drilled	Proved	Sold	Committed	On-line
Chevron/SDG&E/EPRI/DOE-demo*	Heber	50	B	yes	yes	no	no	no
Chevron/SCE	Heber	50	F	yes	yes	no	no	no
Magma	East Mesa	10	B	yes	yes	no	yes	1978
Republic/DOE-loan	East Mesa	50	F	yes	yes	no	no	no
Union	Brawley	10	F	yes	yes	no	no	no
CU 1 Venture/DOE-loan	Brawley	50	F	no	no	no	no	no
Republic/DOE-loan	Westmorland	50	F	yes	no	no	no	no
Magma/SDG&E/DOE-demo	Salton Sea	10**	F	yes	yes	no	yes	no
Union/SCE	Salton Sea	10	?	no	no	no	no	no

Code: Drilled = reservoir existence confirmed by deep drilling
Proved = reservoir adequate to support plant (of size indicated) confirmed by flow testing
Sold = contract signed for sale of fluid to power plant
Size = approximate electric power output in megawatts (MW)
Type = B for binary and F for flashed steam
Committed = funds committed to construct power plant
On-line = power plant in operation
DOE-demo = Federal funding directly for construction of plant
DOE-loan = Federal loans guarantee for debt financing

*Proposal for DOE funding rejected in July 1978.
**No electricity output, thermal loop equivalent to 10 MWe.

BACA FLASHED STEAM POWER PLANT

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The Public Service Company of New Mexico (PNM) and Union Oil Company of California submitted a five-volume proposal to the Department of Energy (DOE) on January 31, 1978 in response to DOE's Program Opportunity Notice (PON) GDPP-EG-77-B-03-1717. PNM and Union Oil Company have offered to cost share, with DOE, development of the initial 50,000 kWe of geothermal energy utilizing the Baca reservoir in north central New Mexico. The geothermal resources discovered to date are capable of supplying enough steam for a generation capacity of 400,000 kWe for 30 years based on calculations of the energy contained in the reservoir fluid alone. The full development potential of the reservoir may be two to three times this value.

DOE has accepted our proposal as responsive to the program opportunity notice. Both companies responded to over 35 written questions which were required for submittal prior to March 3, 1978. A site team representing the DOE selection board visited the Baca site on Thursday, February 23, 1978 to gain first-hand familiarity with the features of the area and the Union accomplishments in discovering and developing the resource. The proposing team also made an oral presentation to the DOE selection board on February 28, 1978 and responded to oral questions following the presentation.

PNM is continuing to survey geothermal developers in New Mexico as to their schedule and proposed activities. It appears all 8 KRGA's in New Mexico are increasing activities.

PNM has been actively following LASL's Hot Dry Rock Project since its inception. PNM staff have visited the Fenton Hill site on several occasions and have exchanged technical and economic information with Los Alamos regarding not only geothermal, but many other technical areas. PNM recognizes hot dry rock geothermal basins far exceed the thermal capacity of hydrothermal sources; and that hydrothermal reservoirs are not common. The development of a hydrothermal resource appears to have more near term technical suitability and is therefore being emphasized by PNM. It appears that utilization of hot dry rock technology could possibly provide, at some point in time, a useful electrical energy source; PNM therefore fully supports the LASL efforts.

PNM is continually reviewing and assessing geothermal development in all areas of New Mexico as surveying, leasing, and drilling activity is increasing in all 8 New Mexico KGRA's. It is anticipated that geothermal energy could serve initially as a potentially viable energy supplement but not a replacement for accepted baseload energy alternatives. As geothermal growth proceeds and as various field developments occur, confidence will increase and consideration of geothermal energy as a significant portion of baseload supply may eventually take place.

RAFT RIVER 5MW GEOTHERMAL PILOT PLANT

DOE - Idaho Operations Contract EY-76-C-07-1570

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Introduction The Idaho National Engineering Laboratory geothermal programs have been geared to the utilization of moderate temperature hydrothermal resources (say 280°F to 350°F). An outgrowth of this work has been the design of a 5MW(e) binary cycle pilot plant to be built in the Raft River valley in Idaho. This plant will utilize state-of-the-art components but will employ a dual boiling power cycle using isobutane as a working fluid. It will be designed to take maximum advantage of the low average seasonal temperatures and will contain sufficient instrumentation and data aquisition equipment to obtain accurate performance data. In addition, some of the large heat exchangers contain special instrumentation to obtain details of their performance.

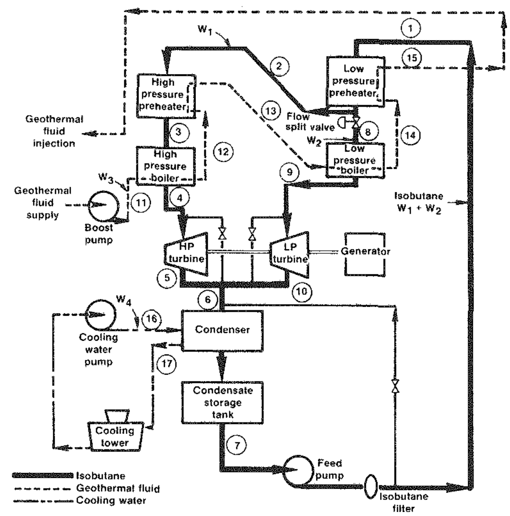
Design was completed on this facility in January 1978. Construction is scheduled to start August 1978. Plant startup and operation are scheduled for July 1980. The following sections of this paper provide a detailed description of the 5 MW(e) facility.

Power Cycle Selection and Description A variety of working fluids and cycles were initially studied for moderate temperature power applications. It was found that the dual boiling cycle had significantly better performance than either the single boiler cycle or a supercritical cycle when resource temperatures were about 300°F or below.

Figure 1 is a diagram of the dual boiling cycle. The state points are those resulting from optimization using a 290°F resource [1]* which is the design geofluid temperature selected for the Raft River 5MW pilot plant.

In this cycle, isobutane condensate is heated by the low pressure preheater to the approximate temperature of the low pressure boiler (180°F). Upon leaving the low pressure preheater, the isobutane flow is split; about two thirds of the flow going to the high pressure preheater where it is heated to the high pressure boiler temperature of 240°F while the remaining one third goes to the low pressure boiler where it is vaporized. No attempt is made to recover the energy lost by throttling the flow to the low pressure boiler.

*Numbers in brackets refer to References at the end of the paper.



Isobutane System	Geothermal Water System	Cooling Water System
W1 = 9.34x10⁵ lhm/hr	W3 = 1.04x10⁶ lbm/hr	*W4 = 7.53x10⁶ lbm/hr
W2 = 6.13x10⁵ lbm/hr		
1 105°F	11 290°F	16 75°F
2 180°F	12 250°F	17 95°F
3 240°F	13 222°F	
4 240°F (381.6 psia)	14 190°F	
5 130°F	15 144°F	*Flowrate is sized for 100% bypass around turbine
6 128°F		
7 101°F (77.5 psia)		
8 180°F		
9 180°F (203.0 psia)		
10 123°F		

Figure 1 - Dual Boiling Cycle

Performance studies have shown that in the moderate temperature range the dual boiling cycle results in better geofluid utilization than either the supercritical or the single boiler cycles. The improvement is about 23% for a 290°F resource. The improvement provided by the dual boiling cycle increases as resource temperature decreases and decreases with higher resource temperatures so that by 340°F there is no merit in the use of dual boiling cycles.

The system has been designed to take maximum advantage of the seasonal variations in ambient temperature. Condensing conditions for a 65°F wet bulb temperature, which corresponds to a 95% condition, is 105°F (78 psia). At minimum tower conditions, a condensing temperature of ∿66°F (42 psia) is obtained. The resulting increase in average power production over a year is estimated [2] at 20-25% compared with the constant power.

Heat and Power Balance The system is designed to operate over a wide range of ambient conditions. The nominal design point is 5MW(e) gross at an ambient wet bulb of 65°F. Up to 7.4MW(e) gross can be generated at lower ambient temperatures. A breakdown of the heat loads and power requirements based upon the nominal 5MW(e) case is given in Table I.

Table I - Heat and Power Balance

		MW
Heat Addition		
L.P. Preheater		14.0
L.P. Boiler		10.0
H.P. Preheater		8.5
H.P. Boiler		12.5
	Total	45.0
Heat Rejection		
Condenser		40
Turbine Work		5
Turbine Gross Power		5
Feed Pump		0.71
Cooling Tower		0.59
Geothermal Booster Pump		0.14
	Total Losses	1.44
Net Power Nominal Condition		3.56

Physical and Design Description The location of the facility in Idaho and the general arrangement is shown in Figure 2.

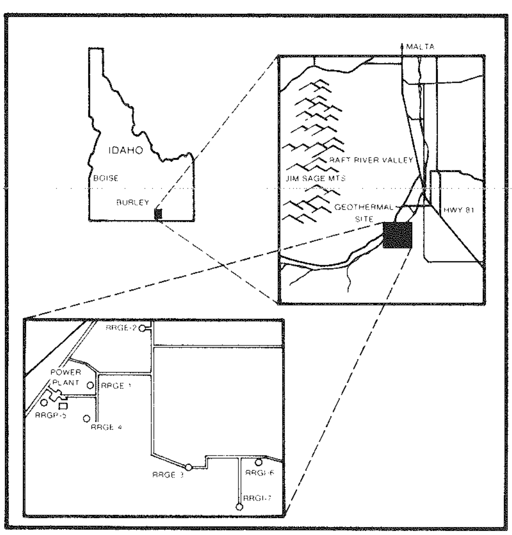


Figure 2 - Raft River Geothermal Site

The power plant area is divided into a process area that contains the heat exchangers, turbine generator and feed pump. Adjacent to this area are buried storage tanks for the isobutane and propane.

Because of the flammable working fluid, the system is designed using the National Fire Protection Association (NFPA) Standards as the governing code. Power Plants are not specifically included in the facilities covered by the code. NFPA No. 59, "Standards for the Storage and Handling of Liquified Petroleum Gases at Utility Gas Plants" was selected as the governing specification supplemented by the ASME Boiler and Pressure Vessel Code (Section VIII), the Power Piping Code (ANSI 31.1) and the Refinery Piping Code (ANSI B31.3).

The geothermal systems have a design pressure and temperature of 250 psig and 320°F. The isobutane system, except for the condenser, design conditions are 650 psig and 320°F. The condenser is designed to the lower conditions of 230 psig and 280°F.

The design pressures were selected to permit the use of propane as a working fluid. From a thermodynamic point of view, the Raft River resource temperature is at the point where the preferred working fluid changes from isobutane to propane [3].

Component Descriptions Feed Pumps - The feed pumping is provided by two parallel vertical turbine pumps rated at 1514 ft and 1747 gpm each. Each pump has six stages and a 500 hp motor. The pump efficiency at rated conditions is 78 percent. The pumps are sized for the minimum condenser pressure of 42 psia.

Geothermal Boost Pumps - The geothermal boost pump provides the head required to pump the geothermal fluid through the heat exchangers and through the transmission lines to the injection pumps. Two parallel, vertical-split-case centrifugal pumps (each with a head of 272 ft at a flow of 1115 gpm, an efficiency at this operating point of 80.5 and driven by a 125 hp electric motor) provide this capability.

Heat Exchangers - The heat exchanger characteristics are defined in the following tabulations:

Heat Exchanger	Surface Area-ft^2	L. ft	Dia. in.	Wt. Tons
L.P. Preheater	30,039*	49	50	43
L.P. Boiler	5,938	42	33/68	20
H.P. Preheater	15,059*	50	35	22
H.P. Boiler	5,938	42	33/68	20
Condenser	56,996	50	88	140

*Extended Surface

The tube material on all geothermal fluid heat exchangers is Admiralty brass. The tube sheets are Aluminum Bronze clad carbon steel. A geothermal side fouling factor of .0015 hr-ft^2-°F/Btu and an isobutane side factor of .0005 hr-ft^2-°F/Btu were used for the design of the geofluid heat exchangers.

The condenser is made of carbon steel throughout, including the tubes.

Cooling Tower - The cooling tower is a crossflow, two cell, mechanical draft, wet cooling tower. The tower is constructed of treated douglas fir and redwood. Pumps circulate 15,373 gpm of coolant. Treated geothermal water is used for coolant makeup.

Turbine-Generator - The turbine will be a radical inflow design. Specifications permit either single or double casing units to accommodate the high and low pressure streams. A single generator is required.

Production and Injection System Description
The relative arrangement of the wells and the planned routing of the supply and injection lines are shown in Figure 2. All lines are made of cement-asbestos pipe with transition to steel pipe at the wells and the plant. The cement-asbestos pipe is buried to a depth of about 2-1/2 ft. The supply lines are insulated with urethane foam to limit the temperature drop to less than 1.5^{o}F/mile.

Pumps will be installed in each of the supply wells. Raft River resource temperatures permit the use of submersible pumps and our test experience with these pumps have been very good. They are about half the cost of shaft driven pumps and require virtually none of the operational restrictions (warmup) that are required by shaft driven pumps.

The pilot plant requires about 2250 gpm of geofluid 290^{o}F for full power operation. In addition, approximately 200 gpm will be required for regulation and another 400 gpm for experiments which are under way at Raft River. This gives a total flow requirement of 2850 gpm. To provide this flow and its injection, four production wells and three injection wells will be drilled, including a standby for each. A summary of the well status is given in Table II.

Table II - Production and Injection Well Data

Production Wells

Designation	Well Depth ft	Cased Depth ft	Remarks
RRGE-1	4989	3623	1-leg
RRGE-2	6543	4227	1-leg
RRGP-4	∿5500	∿3500	3-leg (when complete)
RRGP-5	5500	Now Drilling	3-leg (standby)

Injection Wells

Designation	Well Depth ft	Cased Depth ft	Remarks
RRGE-3	5917-C 5532-B 5853-A	4237	3-leg
RRGI-6	3972	∿1700	1-leg
RRGI-7	3500	2000	1-leg (Now Drilling)

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3. Ingvarsson, I. J. and Turner, S. E., "Working Fluid and Cycle Selection Criteria for Binary Geothermal Power Plants with Resource Temperatures in the Range of 220^{o}F to 400^{o}F," INEL Report TREE-1108, April 1977.

NCPA VIEWS GEOTHERMAL ENERGY

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Small utilities have historically been a single-faceted operation in a multi-faceted industry. That is, they distributed power to ultimate consumers but did not participate, generally, in the other most major modes production or transmission.

In the last few years this trend has changed and it continues to advance. The reasons for this change are threefold. First, the formation of joint agencies; second, the Arab Oil Embargo which gave emphasis to previous actions and third, a realization that small utilities have a utility responsibility which must be met in a day of energy uncertainties and long-range planning.

The joint agencies permitted small utilities to accomplish two aims. First, by acting in concert they could purchase an equity or provide for unit purchases from a large plant being installed which they, by themselves, could not endeavor as a finite experience. Second, it permitted these small utilities to go ahead on certain projects which they could undertake as a group but could not undertake as individual utilities.

The Northern California Power Agency (NCPA) is an example of these actions. The members of the NCPA are the eleven municipal utilities with one Rural Electric Cooperative as an Associate Member. The peak demand of the group in 1977 was 642 Megawatts. Compare this with 1970 when the load was 500 Megawatts. By 1985 the peak demand is estimated to be 987 Megawatts. However, the loads of individual members range in 1977 from 2.5 Megawatts to over 200 Megawatts, but most are in the range of 20 to 60 Megawatts peak demand.

These cities now purchase their power requirements; but one look at the growth projections demands that they take appropriate action.

Certain members of the agency have moved ahead on geothermal projects. Specifically, in two projects in The Geysers, 167 Megawatts is in the process of regulatory permit. We hope to have an initial 110 Megawatts on line in late 1981.

You may ask, "Why geothermal?" The reasons are these: It is and has proven to be a reliable source; it is a technology, at least in The Geysers, which has been demonstrated; it comes in the correct bite-size for small utilities acting in concert; it is and can be absorbed into their loads now and in the future; its baseload characteristics are viable for their load curves. Our predictions show that more can be utilized and NCPA will move ahead to implement additional sources as rapidly as possible. By 1985 the agency's members can utilize from 220 to 440 Megawatts additional generating capability. Although as prudent planning dictates, the agency will continue to investigate other sources.

We are convinced that geothermal in its various forms will continue to play a vital and expanding role in the energy role of California and the West and in the plans, planning and source implementation of NCPA, and its members - the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara and Ukiah and Associate Member, the Plumas-Sierra Rural Electric Cooperative.

THE HEBER GEOTHERMAL (STEAM) ELECTRIC GENERATING PLANT

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Introduction The Southern California Edison Company (SCE) is currently designing a 45 Megawatt (Net) Geothermal Steam Electric Generating Plant for operation in the southern area of the Imperial Valley, California. SCE will build, own, and operate the first "double-flash" steam unit in the United States. The plant will receive geothermal energy in the form of low-saline brine from the Chevron Resources Company, a Division of Standard Oil of California. In January, 1978, SCE and Chevron executed a letter-of-intent which provides for a definitive geothermal energy contract to be negotiated. Such a contract would include this first steam plant.

The plant will be located south of the city of Heber, California in the geothermal area known as the Heber anomaly, situated approximately halfway between El Centro, California, and the Mexican border. The plant will be approximately 1/2 mile from the San Diego Gas and Electric Company's binary plant.

Concept and Design The current design concept utilizes low-saline geothermal brine supplied by Chevron from the Heber anomaly, to produce "double-flash" low-pressure steam to drive a turbine-generator. The turbine will be designed for 50 Megawatts gross output with a three-inch HgA exhaust pressure, employing a surface condenser interconnected with a wet cooling tower system.

The present engineering concept is based on the following general design factors:

1. The plant design will be for a "firm resource" generating facility with an operational life of 30 years and capacity factor of 75% or greater.

2. Chevron will produce and deliver brine to SCE at about 360°F. Brine liquid flow is estimated at 8 million pounds per hour.

3. Preliminary design is based upon two-stage steam separation at about 60 psia and 16 psia at 100% load. About 55% of the total steam (1,200,000 lb. per hour) is at the higher pressure.

4. Arrangements for transmission of the electrical energy will be made with the Imperial Irrigation District.

5. SCE will utilize steam condensate for cooling tower makeup.

6. After steam separation, SCE will pump the spent cooled brine from the separators to an injection system operated by Chevron.

7. To meet present Imperial County requirements for "100% injection" into the geothermal reservoir, Chevron will process and treat water from the New River for injection makeup. The amount of injection makeup is equal to the amount of steam condensate used for cooling tower makeup. As much as 3500 acre-feet per year will be required.

Costs Final anticipated costs of the total project will be determined after preliminary engineering is completed and the geothermal brine supply contract with Chevron is finalized. Roughly, 1982 capital costs could range between \$60 to \$80 million for the plant, including the systems for steam-separation and New River water treatment.

Project Timetable To maintain the project schedule, SCE commenced preliminary engineering of the double-flash plant concurrent with the start of contract negotiations. Preliminary engineering will be completed by the end of July, 1978. Permit applications will then be filed by both Chevron and SCE.

SCE will begin final engineering subsequent to SCE and Chevron finalizing contractual agreements. Construction will start in mid-1980 with a plant in-service date of October 1982. Close monitoring of the Unit will follow to determine whether geothermal energy recovery systems in the Heber anomalay are sufficiently reliable for SCE to install future additional electrical generating plants.

REPUBLIC GEOTHERMAL, INC. EAST MESA, CALIFORNIA

48 MW NET DUAL FLASH STEAM POWER PLANT

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Introduction The Republic East Mesa 48 MW net Power Plant has been designed in parallel with Republic's development, testing and evaluation of hot water geothermal resources on a Federal leasehold, acquired through competitive bidding, in the East Mesa KGRA, Imperial Valley, California.

On the basis of promising characteristics shown by tests of initial flows from three exploratory wells drilled by Republic, the first loan approved under the ERDA, now the Department of Energy, Geothermal Loan Guaranty program was granted to Republic. This Bank of America loan provided funds to drill additional confirmation wells, to extensively flow test all wells, and to proceed with the planned field development for an electric power plant of approximately 50 MW capability.

To minimize the time between geothermal field development and on-line electrical power production, Republic contracted with the General Electric Company and the Rust Engineering Company, a subsidiary of Wheelabrator-Frye, Inc., for preliminary design of the power plant even though the ultimate power plant owner had not yet been established.

As a result, the design of a 48 MW net dual flash steam turbine power plant has now been completed including equipment specifications and evaluated sales quotations from the major equipment vendors.

The plant incorporates three high pressure (55psia) steam turbine elements and two low pressure (16 psia) steam turbine elements. One high pressure turbine element drives a 10 MW gross electric generator while the other two high pressure elements are arranged in a double flow casing mounted in tandem with the two low pressure turbine elements arranged in a second double flow casing to drive a 54 MW gross electric generator.
Figure 1 is the basic flow diagram for the power plant.

The Ralph M. Parsons Company has been selected as the engineer-constructor to provide detail design, procurement, and construction services for the plant as part of a joint under-

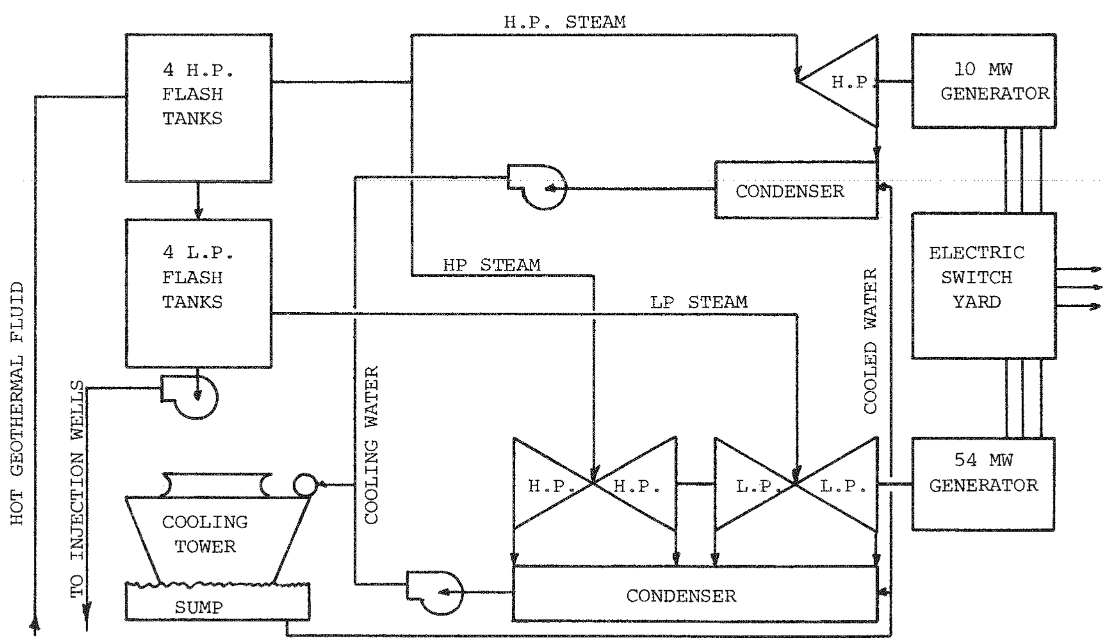

FIGURE 1 BASIC FLOW DIAGRAM

taking with General Electric Company to supply a commercially warranted power plant installation. Start-up of the 10 MW element is expected early in 1979 with the 54 MW element to follow early in 1980.

Project Concept Initial flow tests of Republic's East Mesa exploratory wells early in 1976 gave evidence of a medium temperature (325F to 360F) reservoir with high well productivity. The geothermal fluid had very low salinity (less than 2000 ppm), no detectable hydrogen sulfide, very low noncondensible gas content, and minimal corrosive and scale forming constituents.

The benign nature of the East Mesa geothermal fluid opened up the possibility of accelerating power production from hot water resources by the utilization of conventional steam turbine technology. Discussion with major national and international turbine manufacturers confirmed this potential. Manufacturing lead times had become shorter because of a decline in worldwide merchant marine construction. Engineering analysis and experience from operating geothermal plants gave manufacturers confidence that current metallurgical and engineering design practices would be applied directly to commercial use for the East Mesa resource. These assurances led Republic to proceed with a plan to achieve early commercial power production at East Mesa using fully developed and warrantable conventional steam turbine power plant technology and equipment.

In addition to acceleration of power production, design of the power plant coincident with testing and development of the geothermal resource would make possible optimization of each element of the design from producing reservoir through the power plant, and on to the injection reservoir.

Consequently, the economic or technical distortions that are created by the institutional barriers inherent between resource producers and power plant owners could be minimized for this pioneering project.

Baseload Priority High capacity factor baseload operation shared top priority with commercially warrantable equipment as design criteria.

The economics of a geothermal power plant installation lead naturally to baseload operation since both the resource field development and the power plant are very capital intensive with relatively minor variable operating costs. Consequently the incremental energy production cost is very low. From an operating point of view, baseload operation provides the steady, continuous flow of geothermal fluid which maximizes resource production. Since the incremental cost of producing electrical energy from geothermal fluids will remain relatively insensitive to inflationary forces, geothermal energy can be expected to provide low incremental cost base load energy over the full project lifetime. Accordingly, the East Mesa power plant was designed to permit safe and orderly start-up and shutdown of the plant under both normal and emergency conditions, but no special load-following or part load capability was provided.

Design Team Based upon a demonstrated ability to provide commercially available equipment suitable for the East Mesa geothermal application and an expressed willingness to warrant the thermal performance of the total power plant, the General Electric Company, Lynn, Massachusetts and the Rust Engineering Company, Birmingham, Alabama were selected by Republic to design the East Mesa power plant. Process design, equipment specifications, vendor evaluation, equipment arrangement, operating procedures, and cost estimates were to be prepared to the point where a plant owner could contract for construction of the project.

Following procedures utilized in the design of overseas marine propulsion power plants, the General Electric system engineering section of the Medium Steam Turbine Department worked directly with Rust engineers in the development of the plant design. Frequent project review meetings between the design team and Republic's engineers insured coordination of the plant design with the acquisition of data from the on-going geothermal field tests.

Progress of the design effort was monitored by Wheelabrator-Frye, Inc., the parent of Rust Engineering, which had been granted an option to acquire an equity interest in the power plant at the conclusion of the design period. However, Wheelabrator-Frye chose not to exercise its equity option because of its expanded financial commitment to Solvent Refined Coal process development.

Upon completion of the preliminary design, Republic selected the Ralph M. Parsons Company to provide detail design, procurement, construction, operator training, and start-up services for the power plant project in a joint undertaking with the General Electric Company. Implementing contracts are now being finalized which will permit an early project construction start.

Turbine Design Studies To determine plant sensitivity to changes in resource temperature, steam turbine performance was analyzed early in the design process for geothermal hot water resources covering temperatures ranging from 300F to 400F. In the first instance, these analyses clearly demonstrated the economic advantages to be obtained by utilizing two stages of steam flash in preference to either a single stage or three stages of flash. In the second place, these analyses revealed that a steam turbine optimized for a 350F resource temperature performed surprisingly well over the full 300F to 400F resource temperature range studied. The mass flow of geothermal fluid must be increased as resource temperature drops, but generating capacity remains relatively constant. Consequently, should resource temperature drop with the passage of time, increasing the number of wells supplying fluid to the power plant will be the only modification required to maintain full plant capacity output.

Initially, the plant was being planned around use of a four-flow dual admission steam turbine generator. However as detail turbine design analysis progressed, the use of separate high pressure and low pressure turbine elements were found to provide significant benefits in reduced shaft lengths and simplified inlet valve arrangements. Consequently, the turbine design was changed to a double flow high pressure section and a double flow low pressure section in tandem driving a 54 MW gross electric generator.

The historical ambient air conditions as shown in Figure 2 were used to select the optimum combination of turbine annulus area and cooling water temperatures to minimize exhaust losses. The East Mesa conditions led to a turbine design backpressure in the range of 3½" to 4" Hg. To reduce foundation and turbine generator profile heights, side exhaust turbines will be provided.

Wet Bulb Temperature	Time Duration Hours	%
84°F	832	10
76°	1664	20
67°	3328	40
57°	1664	20
48°	832	10

Figure 2 East Mesa Ambient Temperature

To facilitate the desired high capacity factor mode of operation, the turbine generators were designed to minimize the frequency and duration of maintenance and inspection shutdowns. Multiple trains of cooling water pumps, cooling tower sections, production and injection lines and steam flash tanks will minimize the likelihood of unscheduled total plant shutdowns. Special pressure monitoring taps are expected to reduce the frequency of scheduled inspection shutdowns and borescope observation ports will reduce the duration of those that are required.

With the ultimate power plant owner unknown during the design stage, emphasis was placed upon producing a design which would be relatively simple to operate and maintain. Since the ultimate owner could be a special entity formed for project financing purposes, the plant designer and equipment vendors have been selected who will make available operations assistance and major maintenance service over the plant lifetime.

Cooling Water System Design The low noncondensible gas content of the East Mesa resource makes possible the use of direct contact spray type condensers. Condensed steam will be more than adequate to supply cooling water makeup. The excess will be blowndown and injected into the reservoir along with the 80% of produced liquid remaining after the two flash stages.

Cooling towers have been selected for the East Mesa plant in preference to cooling ponds on the basis of lowest total evaluated costs although the cost differential was not large. Condensate (cooling water) pumps will transfer the cooling water from the condensers to the cooling tower spray headers. Condenser vacuum will draw the cooled water from the tower sump back into the condenser.

Electric motor driven vacuum pumps proved to be more economical for removal of noncondensible gases and in-leakage air from the condenser than steam ejectors, primarily because of the relatively low steam pressure available.

The power plant plot plan is shown by Figure 3.

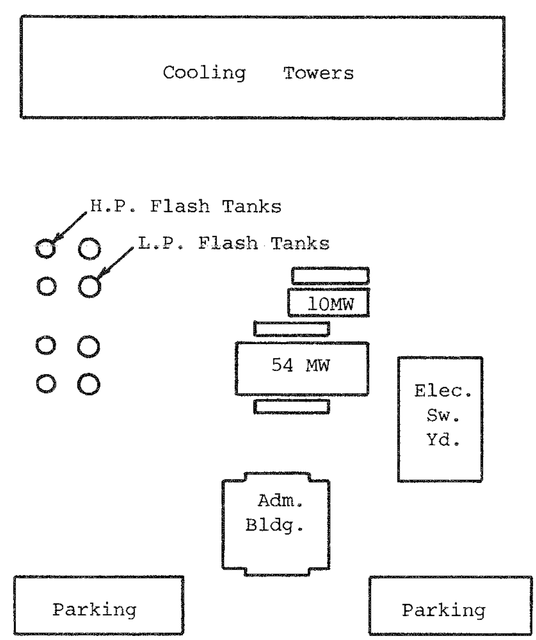

Figure 3

POWER PLANT PLOT PLAN

Gathering System Design With two stages of steam flash, it was necessary to determine whether the steam separator/flash tanks should be located at the well head or at the power plant and to evaluate the advantages of single phase versus two phase fluid flow in the gathering lines. In turn, this parametric study required choices a) between flashing flow in the wells and deep well pumping and b) between vertical and slant drilled wells.

Minimum cost was obtained by the use of vertical wells equipped with deep well pumps, wells and surface gathering lines operated under single phase flow conditions, and steam separator/flash tanks located at the power plant. From concurrent instrumented loop flow tests of the East Mesa geothermal fluids under steady state conditions, this arrangement was found to provide an additional advantage in isolating any tendency for scale formation to the flash tanks, simplifying scale removal.

Subsequent field testing has demonstrated the use of scale inhibitors to be very effective for preventing scale formation in the East Mesa fluid. Although it appears that scale inhibitors will be economically superior to mechanical cleaning of the relatively small quantities of scale that would otherwise be formed in the flash tanks, the ability to control the location of potential scale formation is a significant design safety factor.

Field test operation has demonstrated the commercial availability of two types of pumps suitable for down-hole pumping of the East Mesa geothermal fluid. Both line shaft pumps with surface mounted motors and submersible electric motor driven pumps have been tested satisfactorily at East Mesa.

Adoption of deep well pumping for East Mesa increased the on-site plant power consumption from 6 MW to 16 MW. In order to maintain the originally planned 48 MW power sale, the installed generating capacity had to be enlarged to offset this 10 MW increase. This could be accomplished by either increasing the size of the planned 54 MW turbine generator or adding a separate 10 MW turbine generator. Although increasing the size of the main turbine generator would provide a slightly lower installed capital cost, it was discovered that the shorter manufacturing time for a single high pressure turbine driving a 10 MW generator would permit power production a year earlier than would be possible with the larger unit. The cash flow provided by the earlier power production in combination with the ability to test and clean up all the production wells under full flow conditions during the year prior to operation of the larger unit, led to the selection of two turbine generating units. Republic has placed an advance order for the 10 MW unit with delivery scheduled for December of this year.

Power Plant Costs The power plant as shown on Figure 3 is estimated to have a capital cost of $38,905,000. Associated gathering and injection lines, exclusive of wells and well pumps, are estimated to cost $12,669,900 for a total power plant project of $51,574,900. These costs are in current dollars and include neither inflation nor owner's financing costs.

Annual operating costs, exclusive of heat energy and fixed plant costs, are estimated to be $2,400,000. An on-site work force of 18 is planned with major maintenance to be performed by outside contractors as needed.

Current Power Plant Project Status Applications for permits for the 10 MW turbine generator installation were submitted to the U.S. Geological Survey (USGS) and Bureau of Land Management (BLM) in October of 1977. USGS, with the assistance of BLM and Imperial County, is nearing completion of a joint Environmental Assessment-Environmental Impact Report (EA-EIR) for the project. Approval to start construction is expected in mid-August 1978.

Permit applications for the 54 MW turbine generator were submitted in January 1978 to BLM which will be the lead agency for the larger unit. Aproval is expected in February 1979.

When the complete power project is in operation, the 4160 volt, 10 MW generator will feed into the power plant auxiliary power bus. During the first year when it is operating alone, the 10 MW generator will feed into an Imperial Irrigation District (IID) 4160 volt/34,500 volt transformer for transmission over an existing line to IID's load center. When the 54 MW turbine generator goes into service, the 34,500 volt line will be removed. Plant output will then feed a 13,500 volt/161,000 volt step-up transformer. IID will construct several miles of new 161,000 volt transmission line to connect to an existing IID transmission line.

Since the 10 MW turbine utilizes only one stage (H.P.) of steam flash, one row of turbine blades will be omitted during the first year of operation. This will result in a 20 psi reduction in steam pressure, thereby increasing the quantity of steam produced per pound of geothermal fluid, and improving plant heat rate. The row of blades will then be installed at the first annual inspection to raise operating inlet pressure to match the H.P. stage of the 54 MW turbine generator.

Contracts for construction of the plant are being negotiated with Parsons and General Electric. Plant financing arrangements are being developed and negotiations for the sale of the power to a utility customer have progressed to the point where the planned 1979 and 1980 operating dates appear to be realistic.

STATUS REPORT ON THE GEYSERS PROJECT

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Pacific Gas and Electric Company's Geysers Geothermal Power Project, located in Lake and Sonoma Counties in Northern California, is still the nation's only commercial geothermal development for the production of electric energy and remains the largest geothermal installation in the world, a position it has held since 1973. The Geysers Project has been well described in the literature, so this summary report dwells only briefly on the development to date. The Geysers Project started in 1958 and in 1960 the first unit went into operation. The 11 units now in service have a total capacity of 502 MW. Four units, Nos. 12, 13, 14, and 15, are currently under construction and will come into service this year and next, bringing the total capacity of the project to 908 MW in 1979. At that time PG&E's capital investment in the Geysers will be about 175 million dollars. Units 12 and 14 will be supplied with steam by the Magma Thermal Union group. These units rated 106 MW and 110 MW respectively, are presently about 65% and 25% complete and will come into service this Fall and next Summer. Aminoil, USA will supply steam to Unit 13 rated 135 MW, which is now 25% complete and comes in service next Fall. Thermogenics is the steam supplier for Unit 15 rated 55 MW, which is 50% and will be in operation this Fall. Two additional 110 MW units, 16 and 17 now in design, and four additional units now in early planning will increase the Geysers generating capacity to 1568 MW in 1984. Beyond this, it is believed that our present and possibly future steam suppliers, can develop enough additional resources to support about 1900 MW by 1987, which is the limit of our present planning horizon.

Because the five year schedule normally required to plan design and build a unit was relatively tight, a standardized power plant design using identical major equipment and a power building arrangement will be used for Units 16-21. This will allow the use of one set of plant piping and equipment drawings for 6 different sites. This will result in substantial design cost savings by eliminating the need to staff up for several different designs simultaneously. Additionally, there are cost savings on most of the major power plant equipment.

The most economic and efficient method of extracting energy from the dry-steam resource that occurs at the Geysers is to expand it directly through a steam turbine. The use of binary or other cycles for this resource would be on an unnecessary economic and thermodynamic expense. As may be seen in Figure 1, which is the power cycle of a typical 110 MW unit, and except for flow rates is identical for Units 13 through 21, steam is piped directly from the steam wells to a turbine-generator which exhausts to a condenser. Cycle exhaust heat is removed from the condenser by cooling water, which dissipates it to the atmosphere in a evaporative cooling tower. It is important to note that the amount of water evaporated in the cooling tower is less than that added to the cycle by the condensed steam. This requires that the excess condensate be reinjected into the ground by the steam suppliers.

Over the last few years it has become important to achieve increasingly higher levels of hydrogen sulfide abatement. This resulted in the change from a direct contact-condensing system used for Units 1-12 to surface-condensing systems. In the direct-contact condensing cycle, steam from the turbine exhaust is mixed directly with the cooling water. Hydrogen sulfide is best removed at the condenser gas off-take with the other non-condensible gases but because of the great volume of cooling water contacting the turbine exhaust steam in a direct contact condenser, more than half the hydrogen sulfide is absorbed in the cooling water mixture. This H_2S is subsequently air stripped from the water in the cooling towers and emitted to the atmosphere. In the more costly surface-condensing system, the cooling water and steam condensate remain separated by the tubes. Since the ratio of steam condensate to the cooling water is less than 1:20, the absorption of H_2S in the condensate is much less than in the direct-contact condenser and the majority of the H_2S will be vented from the condenser with other non-condensible gases. These gases will then be treated for sulfur removal by a Stretford plant. The condensate will be mixed with cooling water downstream of the condenser with a minimum of H_2S exiting from the cooling tower exhaust stacks.

Nowhere has a surface condenser operated under conditions similar to those that will be encountered at the Geysers. Little is known about corrosive and erosive effects of geothermal steam exhausting from turbines onto condenser tube surfaces and the affects of large concentrations of non-condensibles in the condensing steam on heat transfer performance. Following consultations wtth several surface condenser manufacturers, PG&E undertook a testing program to determine the affects of Geysers geothermal steam on surface-condenser performance. Although the condenser materials and heat transfer rates chosen for the new surface-condenser are conservative, the test results from the initial operation of Unit 15, the first surface-condenser unit, are awaited with keen anticipation.

The earlier Geysers Units used to be compared to an unattended hydro-electric generating unit in simplicity of operation. In addition to increasing the cost of the units, the addition of the H_2S abatement equipment has greatly increased their complexity. For example, on the recent units the number of motor starters and control and instrumentation is about doubled the earlier units. The auxiliary power requirements have increased over 50%.

In addition to providing an alternative energy source to expensive off-shore fuel, geothermal energy remains PG&E's least expensive source of thermal-electric power generation, although rapidly escalating cost of environmental control systems could change this in the future.

Geothermal energy has become an important supplement in PG&E's mix of electric generating resources. Because the limits of the overall geothermal field at the Geysers have not been defined by exploratory drilling, the ultimate potential there remains unknown but is over 2000 MW. PG&E is willing to participate in the expansion there as fast as it can be developed.

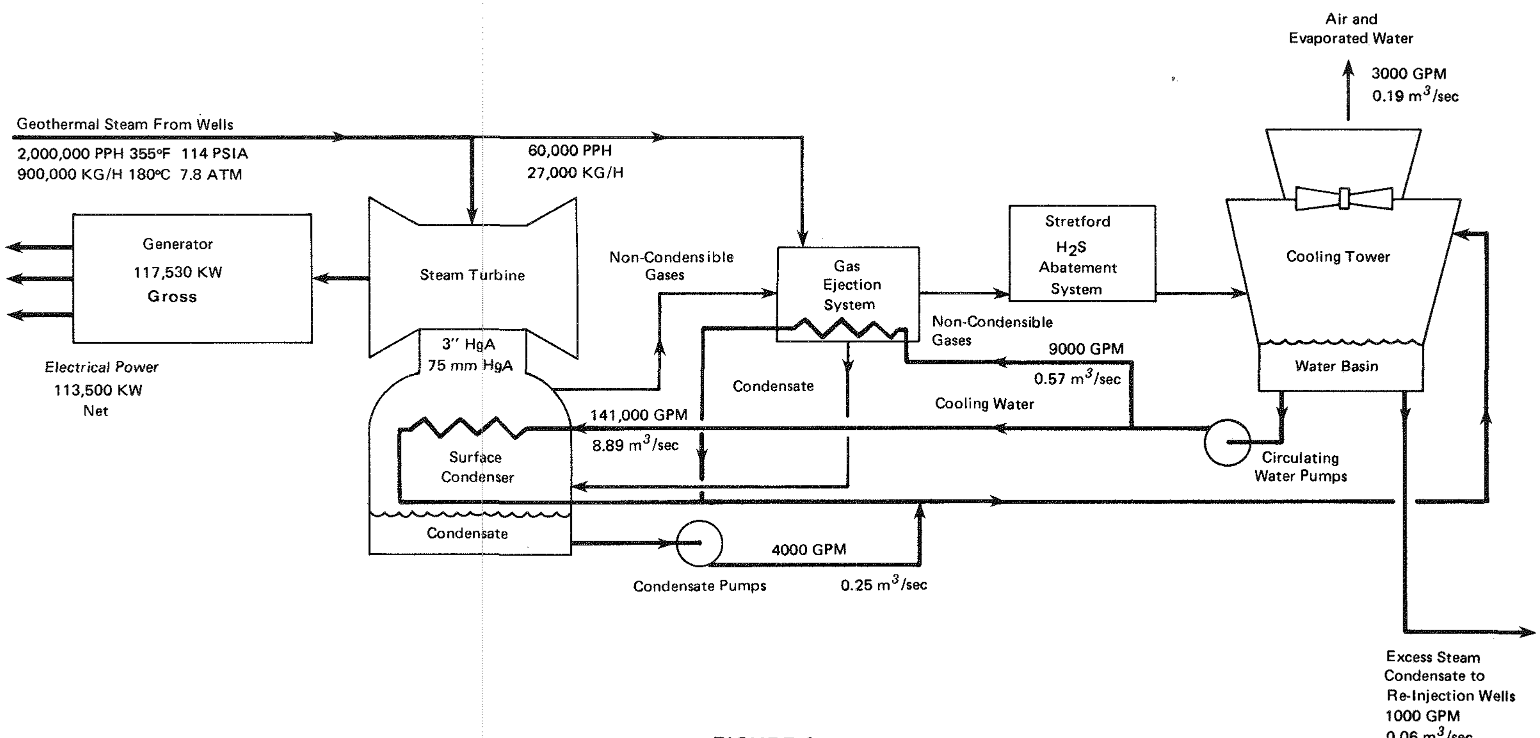

FIGURE 1

MODIFIED SYSTEM CYCLE FOR USING SURFACE CONDENSERS AT THE GEYSERS POWER PLANT

CONCEPTS FOR ADDRESSING THE

RISK OF GEOTHERMAL DEVELOPMENT

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I. INTRODUCTION The purpose of this paper is to provide an outline of a general framework to assist those who have to consider the risk of geothermal development. It is not intended to be a detailed discussion of risk analysis. In order to develop a structure to the discussion, it is appropriate to first define risk which will result in certain implications for its analysis, and then consider the issues that have to be included in an analysis which considers risk.

Risk as defined in Webster's Third New International Dictionary is "the possibility of loss, injury, disadvantage or destruction," and calculated risk is defined as "a hazard or chance of failure whose degree of probability has been reckoned or estimated before some undertaking is entered upon." The definition stated above indicates that if we want to analyze risk, it is necessary to estimate the probability of the occurrence of the various consequences resulting from the actions which we wish to undertake. The requirement to consider risk is also embodied in the National Environmental Policy Act: "that the Nation may . . . attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences . . ."

The Components of Risk Analysis Risk analysis is the determination and evaluation of the likelihood of various consequences that can result from an action. For purposes of discussion, risk analysis can be broken down into the following components:

* Development of indicators (measures) of risk
* Risk quantification (determining the magnitude and likelihood of the consequences of an action)
* Risk evaluation (deciding on the acceptability of risk and evaluating alternatives with differing risk)

In an actual analysis there is considerable interaction between these steps. What we want to calculate (Step 1), our calculation capabilities (Step 2), and our evaluation scheme (Step 3) must be compatible. A schematic representation of risk analysis is presented in Figure 1.

The consequences of an action like geothermal development can occur in several ways. For purposes of discussion, we can divide the areas of risk into three general categories. These categories reflect the papers that are to follow.

(i) Public risk (i.e., societal property loss or expected fatalities)

(ii) Environmental risk

(iii) Economic risk

The first two deal primarily with societal concerns and the developer of geothermal energy has to consider them through the regulatory process. Economic risk is primarily the developer's concern, although lending institutions and utility commissions can have a significant impact.

This paper is organized as follows. In Section II we discuss the development of the measures of risk. Considerations in quantifying risk are discussed in Section III, and Section IV discusses concepts in evaluating risk. Conclusions are presented in Section V.

II. DEVELOPMENT OF MEASURES OF RISK The basic idea in developing measures is to assist in providing meaningful quantitative estimates of the consequences and associated uncertainties of geothermal development. Let us illustrate this by taking some examples in each of the three general categories of risk mentioned above.

Measures of Public Risk What are measures of public risk? Some that have been proposed in the literature and used in practice are:

Societal Risk - total expected property loss (dollars) and total expected fatalities per year

Individual Risk - probability that an individual will become a fatality in any year

Group Risk - probability that an individual in a particular group will become a fatality in any year

Risk of Different Levels of Loss or Fatalities - probability of exceeding specific levels of loss or numbers of fatalities per year.

The risk-quantification model and the evaluation process must be designed to deal with risk expressed in terms of these measures.

Measures of Environmental Risk The environmental risk can be broken down into several different components. For example, there may be the impact on the terrestrial biota, on the aquatic life, and on water quality. For each of the areas of impact, quantitative measures need to be developed so that a meaningful estimate of risk can be made. Let us illustrate these concepts by considering surface water and groundwater which are impacted by geothermal development. For surface water we would be interested in at least two general measures; (i) availability and (ii) quality. These general measures would have to be expressed in more specific terms e.g., availability in quantity/unit time, and quality in terms of dissolved solids, etc. For groundwater, we would be interested in (i) level and (ii) quality. As above, specific measures should be developed. It is these specific quantitative measures that must be developed for all the components of environmental impact, because it is in terms of these quantitative measures that the environmental consequences of geothermal development must be considered.

Measures of Economic Risk The general measure of economic risks is money (dollars). However, it is important to recognize that not all dollars are identical in the evaluation process. Capital expenditure, operation and maintenance cost, long- and short-term debt, can all be expressed in dollars; however it may not be appropriate to consider them as equivalent. The interest rate reflecting the time value of money has also to be considered.

The following is a description of some of the measures that may be used in assessing the cost impact of various components of electricity-generating and related systems. The discussion is from a utility company point of view and its main purpose is to emphasize the idea that there are several measures of economic risk. Economic attributes can be divided into two major categories; project cost measures and measures of the utility's financing ability.

Project Cost Project cost can be effectively expressed as levelized mills per kilowatthour and can be calculated using the ERDA-EPRI required-revenue methodology. For projects producing the same kilowatthours per year, it may be useful to calculate and compare the annualized cost and the total levelized system cost in addition to using mills per kilowatt-hour. All three measures allow one to look at the lump sum differences, percentage differences, and year-to-year differences in project cost for various alternatives. Often one number may provide a more appropriate perspective than another number in a particular decision-making context.

In some instances, it may be possible to also address many other issues using only ERDA-EPRI measure. For example, if particular expenditures would cause a utility's credit rating to drop, this may imply that the rate of interest to be used in calculating the expense of borrowing money should be made higher. The interest rate parameters in the ERDA-EPRI methodology could be adjusted to take such a financial impact into account. Similarly, delays in project licensing could be modeled as higher costs for the use of money. However, it may not be easy or desirable to capsulize all financial effects, using only a project cost measure. In that case certain other measures may be useful.

Financing Ability

Coverage A statistic used to determine the relative health of utility companies is coverage. This is generally the ratio of income to interest on debt, calculated on an annual basis. Frequently, as part of bond covenants, utilities are precluded from issuing more debt unless their coverage is above a certain specified value. The people who market or purchase debt securities are interested in how close the utility comes to being able to pay its debt obligations.

Quality of Earnings In most cases, AFUDC is permitted to be added to the capital cost of facilities rather than deducted explicitly from operating income. Thus the effect of having large capital construction projects underway is that earnings per share can be artificially increased above real earnings that are generated from operating income. Problems can result when a sizable fraction of earnings per share comes from AFUDC rather than from operations. One way of measuring the quality of earnings is to examine the ratio of earnings on operation to total earnings, with higher ratios indicating higher quality.

Amount of CWIP on One Project Utilities involved in large construction projects have a very large amount of CWIP, which, generally, cannot be included in the rate base. The cost of the capital to support such projects is usually treated as AFUDC and is added to the construction cost of the project. Thus it is not funded out of income from operations. When a large project is placed in service, the capital base for rate determinations increases. If the increase is substantial, problems may result from the utility's inability to instantaneously change rates (and thus revenues). One way of measuring this potential problem is to examine the relationship between a project's capital cost and the company's total capitalization. Presumably, lower ratios are more favorable in this situation.

For each specific utility and situation, some of the above measures may be used to quantify costs.** We must exercise the usual caution not to double count when selecting a set of measures. The aim is to provide the cost measures that can do the following:

* reflect the total impact on the finances of individual utilities by including as measures the relevant parameters

* provide the flexibility of treating the elements of cost differently for different utilities

* provide the parameters for accurately assessing the mitigation costs of environmental impacts (e.g., capital expenditures for mitigation will affect coverage, quality of earnings, and so on)

* provide the structure, in terms of the cost attributes, to mesh with the risk analysis approach.

III. QUANTIFYING THE RISK The basic idea of quantifying the risk is to determine the probabilities of occurrence associated with different levels of the measures of risk if we follow a course of action. Quantifying risk can be broken down into two steps; (i) identifying the sequence of events that can result in levels of the measures of risk and (ii) developing and using a probabilistic model of this sequence of events. For example, in economic risk we would want to consider the cost of delays. A sequence of events detailing the licensing process, intervention, etc. would have to be developed. The probabilities of these events occurring and the resulting consequences would have to be determined.

Since there are multiple measures of risk, the consequences of any action can be represented by ($\underline{x}$) which is a vector of dimension equal to the number of measures or risk. What we have to determine are the probabilities associated with the occurrence of different levels of $\underline{x}$. These probabilities will in general also be dependent on the mode of geothermal development. Determination of the probability associated with the consequence vector will depend on the probability of occurrence of each individual component and whether the components are probabilistically independent or dependent. Techniques in probability theory allow one to deal with both cases. Both discrete and continuous distributions can be treated.

In identifying the sequence of events, it is important to recognize that human factors must also be considered. Human factors include errors in judgment and interpretation of information, organizational inadequacies (compatibility of design and construction), and deliberate deviations from specification.

IV. EVALUATION OF RISK In the evaluation of risk there are usually two levels of evaluations; (i) satisfying certain minimum criteria and (ii) comparing alternatives over all the areas of impact.

There are no generally accepted methods for deciding on the acceptability of public risk. A criterion of risk acceptability has been proposed by Starr [1]. He suggests that acceptability be determined by comparing the annual probability of death per person exposed with other man-made and natural risks to which society is exposed.

There are two major difficulties with following this approach. The first is that it is based on expected fatalities (that is, there is an averaging process) so that a number of small accidents and one large accident, which both result in the same number of fatalities, are treated as equivalent. However, evidence indicates that society tends to view these events differently. The second is that the public views the risk from different types of events (e.g., dam failure, aircraft crash or terrorist attack) differently. Public safety (risk) is an area which many people believe should be treated separately and only if the public risk is acceptable should an alternative be considered feasible. It does not appear that public risk is a significant problem in geothermal development.

In satisfying certain minimum criteria we are governed by regulations e.g., air quality, or financial community requirements such as return on investment.

Where public risks are not significant and regulatory requirements have been met so that the set of alternatives can be considered a feasible set, multiobjective decision analysis (Keeney and Raiffa, 1976) [2] can be used to evaluate alternative modes of geothermal development. This analysis is based on sound theoretical principals and can consider the multiple measures of risk and the uncertainty associated with their occurrence in a logical and defensible evaluation of the alternative. If the measures of risk have been specified, then a utility function $u(\underline{x})$ is constructed to combine these attributes and provides a single

** We can always use project cost initially as the only cost measure, and then examine whether an additional measure seems appropriate for the problem.

number which indicates the overall desirability of a particular course of action. If uncertainty is present, expected utility is a theoretically sound criteria on the basis of which to rank the alternatives. Details of the theory and assessment technique are provided in Keeney and Raiffa (1976) [2] and in a report for EPRI by Nair and Sicherman (1977) [3].

V. CONCLUSION Uncertainty is associated with the consequences of all our actions including the alternatives available to us in geothermal development. In addition, the consequences of geothermal developments have many different components, including impacts on the environment and economic impacts. Formal consideration of risk is necessary to deal with the above characteristics of the problem. Techniques are available to do this. Development or measures of risk, quantification of risks and evaluation of risks are the three basic steps in risk analysis. With society demanding more information on the risks it is being asked to accept, formal risk analysis is likely to be more prevalent in the future.

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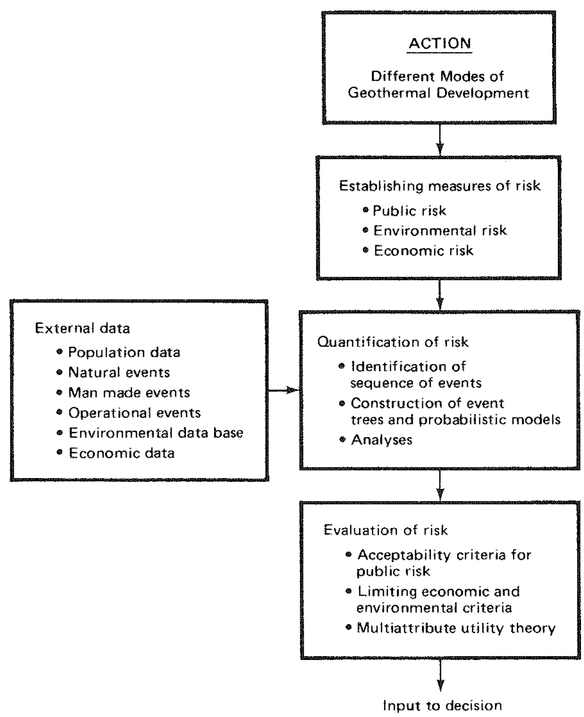

Figure 1. SCHEMATIC DIAGRAM OF RISK ANALYSIS PROCEDURE

ECONOMIC RISK OF GEOTHERMAL PROJECTS

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Methods to standardize appraisals of business opportunities involving uncertainties have used the concept of risk analysis. Risk analysis is believed to be a powerful tool to compare the economic attractiveness of the various investments available to the business community. Natural resource development groups utilize this technique to select their exploration targets and to appraise the anomalies found to allocate additional funds to those providing the opportunity for greatest return per dollar risked.

What is the risk factor used in economic analysis? When the probability of occurrence of any given event has been established, the risk factor will be known. The mathematical concept of risk factor can be considered as: The probability that an event will occur in one of several ways is the sum of the probabilities of the occurrence of all the possible ways that an event can occur.

For example, say a review of exploration work on geothermal prospects determines that in basin fill areas four electrical resistivity anomalies are due to low resistivity sediments and one is due to an unusual amount of heat. The chances for being successful in a temperature confirmation drilling program on these resistivity anomalies will be 1:5. The probability of being successful is not the same as risk. In this example, in five attempts at success in a series when the risk is 1:5, the probability of success is approximately 68 percent.

The summation of risks involved in geothermal development evolves to essentially the question: Can the energy compete with other sources of energy available to the customer and still provide a reasonable rate of return on the necessary investment? The competitive fuel in the area of major geothermal steam occurrences is fuel oil. Coal is a strong competitor for hot water flash systems. Coal prices will probably follow oil prices in the next two decades. At this time, hot water systems at temperatures below 400°F cannot produce electricity as inexpensive as coal fueled generating plants.

A short look at the oil supply situation will provide a background for assessing the risk of oil prices increasing more rapidly than cost associated with geothermal development.

Saudi Arabia oil production is around 8.7 to 9 million barrels per day. A year ago that country produced 10.2 million barrels a day. Present capacity is believed to be 11 million barrels per day. ARAMCO plans to add about 3 million barrels per day capacity during the next 2 years. The capability for producing much more exists. The willingness to produce is another thing that poses a risk to the assumption they will. The Saudis are determined to maintain OPEC as an effective organization and will continue their production at around 8 million barrels per day. World oil demand should continue to increase 2 to 3 percent per year until 1980.

OPEC production now at approximately 29 million barrels per day will gradually move back to the 1977 high of 30 million barrels per day during 1979-80.

All free world net growth in oil demand (now 47 million barrels per day) during the next 3 years will be satisfied by non-OPEC sources: Mexico, North Slope and the North Sea.

Until 1985 world oil prices will be increasing to more than the average rate of inflation. From 1985 on, world oil prices will be increasing at accelerating rates as OPEC countries maximize their return on a diminishing number of barrels.

Natural sources of heat above 450°F in the western United States can produce electricity at prices competitive with low sulfur coals shipped from the Powder River Basin of Wyoming to the electricity generating centers supplying western Nevada and California. Water within the low energy 150°F temperature range can provide processing heat, if the source is in a location where the energy can be used in the United States. It is expected that sulfur limits for fuel oil will be set similar to coal. To meet such standards, additional investment and costs will be required to prepare acceptable fuel. With such increases in cost, new uses for geothermal heat (energy) will become practical. When that happens, more people will become interested in joining the exploration search to find and develop new deposits of heat for production of energy.

The development of a geothermal reservoir is capital-intensive, requires expert planning, and long times from initial expenditure until positive income is achieved. The utilization of a geothermal project requires extensive engineering, approximately 2 years in negotiation with governmental agencies, and significant capital.

The costs of maintaining and operating producing fields is about four to five times greater than the capital investment. An important portion of this cost is associated with the injection system that collects the water and returns it to the subsurface reservoirs after the heat is removed. Reducing these costs is an essential objective if geothermal energy is to be competitive with other fuels.

Countries with high fuel costs and geothermal sites are now developing a wide variety of geothermal plants. Japan appears to be building the most efficient flash systems for use in hydrothermal areas rimming the Pacific Ocean.

Useful geothermal reserve assessment requires professional analysis. The goal is to determine how much heat can be produced at a useful rate and temperature for at least 20 years from one area. This demands a thorough understanding of the manner in which heat is transported to areas of accumulation, how it accumulates, the methods and costs to find, produce and convert to a useable form of energy. With those studies in hand, a person can then determine what part of this resource can be sold in competition with other fuels and thereby establish the size of the reserve.

The supply has been related to all the heat present above an arbitrary temperature datum; the amount of heat between certain temperature levels, that heat contained in producing water, and that heat contained in the rock framework transferred to the moving body of water, and the amount that could be produced if the government would provide various incentives.

These incentives have included tax credits, deductions in tax calculations, investment tax credits, rapid depreciation, and extensive depletion allowances. Other incentives include aid in exploration, aid in developing, engineering of generating plants, financing of generating plants, and reservoir engineering studies. Very little has been prepared showing the increased benefit to governmental programs, including tax revenue by demonstrating the increased flow of dollars from projects that would become profitable with this aid compared to project tax revenues that would be commercial without this aid.

The actual potential of geothermal energy is affected by how the resource and reserves are calculated. These calculations must consider availability and application of governmental incentives, the price of other energy sources versus the market price of geothermal energy, and the reliability of the production forecast. The size of required investment and the expected profit generated by those investments, plus the availability of lands to explore will be the motivating forces in determining the true potential of geothermal energy development in the United States.

The most important factor in converting any resource into a reserve is how the individuals that are actively dedicated to discovery and development attack the problem. The key to successful reserve development is the quality of the people assigned to the task.

The critical economic factors affecting the risk of a geothermal project being successful can be considered in two categories. The first is that associated with the production of the geothermal energy. The second is in the conversion of the energy into a useful form for the production of electricity.

The energy producer, after finding the geothermal anomaly, must consider his risk of resource development concentrated into four major items. These are the reservoir life, the sales price for the energy, the plant design, and the pricing structure.

The number of years of reservoir production at useful temperatures and volume of fluid that can be expected is of utmost importance. The reservoir economic life is affected by the rate of decline in temperature and production as this affects the drilling and equipment investment and the operating costs.

The risk the project succeeds depends upon the price of energy produced. The sales price defines the cash flow available for development and operating expense. This price establishes the limits of investment that can be made and the potential rate of return on this investment. The competitive stature of the resource will be prescribed by the price of the delivered energy. The final size of the economic reserve is thus determined by these factors. That size then determines the amount of risk the energy producer can assume at various stages of exploration and development.

The plant design affects the cost of designing the production mode as the delivered product must conform to the requirements of the plant. Single-phase fluid delivery (for other than dry steam) requires greater investment to maintain that phase from the reservoir into the plant than does a two-phase system. Injection disposal facilities are dependent upon the plant requirements. The rate of production from the reservoir is also dependent upon the plant design. The limits of fluid temperature useful in running the plant are established by the plant's design. The life of the producing facility is seriously affected by this factor.

The pricing structure can encourage efficiency in developing new reservoirs or negate the advantage of searching for deeper, though hotter, horizons. Provisions for reservoir failure can allow the taking of a greater risk in developing the reservoir to its maximum size. If the reservoir performance must be guaranteed by the producer, he can then only develop the amount of energy that has very little risk. Thus, the fuel producer and the utility have little chance for maximizing their return on the use of this impressive source of energy unless pricing structures recognize this effect.

Electricity producers are not prepared to undertake projects that have a risk of complete failure in the early stages. They are not oriented to taking risks of the magnitude considered acceptable by natural resource developers. For instance, developers know the risk of finding one million barrels of oil with a wildcat is about one in forty times being successful. So their organization has the ability to provide for the unsuccessful exploration ventures' effect on their marketable supply of energy. The ability to evaluate and predict the reservoirs' capability for producing certain quantities of fluid is highly developed in oil companies because the few successful finds must be developed to their full capacity.

Utilities historically expect a certain amount of fuel to be delivered on schedule throughout the plant's lifetime. The utility organization has not developed the capability of being comfortable with reservoir engineering analysis. Geothermal energy does not provide the risk abatement feature of having another source of supply that can be brought in to augment a premature declining geothermal energy supply. This is the major risk the utility management recognizes in the economic viability of building a geothermal plant. The risk of having a favorable cost at the Busbar for the electricity produced can be determined after the design of the generating plant has established the production requirements for delivery of the geothermal energy. These requirements are strong factors in the producer of the energy identifying his costs of production and therefore a likely energy sales price.

The fixed costs affect the final price of produced electricity. Dry steam plants can be constructed for a lower investment than single-flash plants. The single-flash plants require a lower investment than the double-flash design.

The lower efficiency of the single-flash plant requires a much higher volume of fluid to be produced and handled to produce the same number of kilowatt hours. This effect of these design segments on the producer of energy and producer of electricity creates the risk that each will have selected the optimum design for their components.

Knowing the size of the available fuel supply lowers the risk of underfinancing a development project. For rocks to be considered a reservoir, there must be sufficient horizontal and vertical permeability to allow the fluid to move easily. A 6,000-foot to 8,000-foot well must sustain flow rates of more than 100,000 poinds of steam per hour, or 500,000 pounds of water (at no less than 325°F) per hour for 20 to 25 years to be considered commercial for electricity generation. Direct use of heat for industrial or space heating and cooling does not require such high heat output. The lower temperatures for such uses can be found in a greater number of anomalies. However, their usefulness is dependent upon low costs being achieved in development and production.

The geologic model that is generally accepted by geothermal explorers and developers has three basic requirements:

1. A heat source (presumed to be an intrusive body) that is about 2000°F and within 50,000 feet of the surface.

2. Meteoric waters circulating to depths of 10,000 feet to 20,000 feet where heat is transferred from the conducting impermeable rocks above the heat source.

3. Vertical permeability above the heat source connecting the conducting rocks with a porous permeable reservoir that has a low conductivity impermeable heat retaining member at its top.

Geological investigation is the necessary ingredient that makes all exploration techniques useful. Broad reconnaissance of the surface data integrated into subsurface data is used to find an area of general interest. The ingenuity of the prospect finder in using data available to all workers determines whether an exploration program moves into advanced stages of using the proper combinations of the acceptable methods. Geologic interpretation of the data acquired may justify the money required for exploratory drilling. The results of the drilling must be integrated into the geologic investigation to determine if a promising prospect is present.

The investigation must establish that:

1. High heat flow or strong temperature gradients are present at depth.

2. The geology provides reasonable expectation that a reservoir sequence of rocks is

present at moderate depths from 2,000 to 6,000 feet.

3. The sequence of rocks offers easy drilling with minimal hole problems.

4. A high base temperature and low salinity waters as indicated by geochemistry of water sources should be present. The surface alteration and occurrence of high heat flow should cover an area large enough to offer the chance for a field capacity of more than 200 megawatts.

Table I from C. Heinzelman's presentation of October 15, 1977 illustrates exploration techniques and associated costs. The overall amount of money (per successful prospect) required is 2.5 million to 4.75 million 1977 dollars. This provides for limited failure and followup costs, but does not include the other exploration failures and land costs.

Table I

Exploration Techniques and Approximate Costs

Objective	Technique	Approximate Cost ($)
Heat Source & Plumbing	Geology	$ 15,000
	Microseismicity	15,000
Temperature Regime	Gravity	20,000
	Resistivity	25,000
	Tellurics and megneto-tellurics	40,000
	Magnetics	15,000
	Geochemistry (hydrology)	12,000
	Temperature gradient - 20 holes	100,000
	Stratigraphic holes - 4	160,000 - 240,000
Reservoir Characteristics	Exploratory wells - 3	1,800,000 - 4,000,000
	Reservoir test	250,000
Total to establish a discovery		$2,472,000 - 4,752,000

This is probably the minimum expenditure to move a portion of the resource into a reserve.

Upon deciding that a significant geothermal anomaly exists, the rate of engineering expenditures must increase rapidly to determine whether the development can proceed. Essentially, there are no set figures for what it costs to develop a geothermal field. The basic reason for this is that each depends upon engineering the development to be compatible with the geology of the accumulation, and the requirements of the electricity generating system. The electricity generating system must be designed within the constraints of available temperature, rate of production, and ambient conditions of the field site. The key variables affecting risk are:

1. Temperature of the fluids produced.

2. Composition of the reservoir fluids.

3. Composition of surface or near surface fluids.

4. Geology of the reservoir framework.

5. Flow rates that can be sustained by the reservoir.

6. Cost of drilling in the prospect area.

7. Well spacing and geometry of the producing and injection sites.

8. Turbine system to be used.

9. General operating costs in the area.

Test Wells - Thermal evaluation requires the drilling of test holes. Heat flow and temperature gradient evaluation requires drilling to intermediate depths. Confirmation drilling requires holes drilled to the actual reservoir for diagnostic evaluation.

Heat flow and temperature gradients measured in the upper 100 to 500 feet depth are useful in describing the area where the heat transfer is most intense. These do give a qualitative analysis as to the location and shape of the hottest near surface heat accumulation. Linear projection of temperatures obtained near the surface cannot be used to predict the temperatures that will be encountered 2,000 to 3,000 feet below the surface, even if the section below has a uniform lithology and the geothermal gradient is a straight slope. The temperature for a fluid-saturated system cannot be projected to a maximum above that for boiling water at the pressure calculated for the depth of the projection. At some point along the boiling point curve, the temperature of the system may become isothermal and the rocks and fluids will have the same temperature for many hundreds of feet deeper. The rock temperature may decrease as a hole is drilled deeper if the hole is on the descending edge of a plume of hot water or merely below the spreading top of a plume. Heat flows from a hot body to a cooler body. This is not a function of being above or below a reference point of depth.

To lower the risk that the performance of the geothermal cell can be predicted, deep tests must be drilled. These holes must be of sufficient size to adequately determine the ability of the reservoir to produce fluids above 365°F at rates of more than 100,000 pounds of steam per hour, or 500,000 pounds of liquid per hour.

To determine if a commercial development is possible, three or four wells must test the reservoir to obtain the basic reservoir engineering data and producibility rates that are necessary. Reservoir pressure drawdown and buildup analysis must be conducted to determine reservoir permeability and extent. Fluid characteristics and analysis of noncondensibles present require extensive flow tests. Injectivity testing is required to develop plans for disposal and pressure maintenance systems. Rocks may produce fluids easily, but may not accept them on return to the reservoir. This must be established in the laboratory and confirmed in the field for a utility to consider risking the investment needed to build a plant.

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 is as follows:

Table II

Development wells - 12	$10,800,000
Injection wells - 6	5,400,000
Pipelines	2,800,000
Miscellaneous field expense (includes interest and working capital)	9,000,000
Power plant	25,000,000
Total	$53,000,000

Economic Considerations - To obtain a comparison of geothermal fuels with the more widely used fuels is quite difficult, because each geothermal area requires a plant design specifically useful for that local area. The California Geyser's steam price of 16.5 mills per kilowatt hour is as inexpensive as geothermal energy can be produced in the United States today. This is a dry steam fuel, and the operators have more than a decade of experience in drilling, completion, and production operations. Optimum techniques have been developed so that maximum steam production per dollar invested can be maintained. The high energy content of this fluid provides a competitive heat rate, easy to construct collection systems, and the most simple of plant and reinjection facilities. The actual cost of the wells is frequently as high as $750,000 to $1,000,000, but the operation and the high utility of the steam allows a minimal price for the energy.

The wide variation of estimates of fuel costs and electricity generating costs derives from treatment of fuel processing and storage expense, income taxes, ad valorem taxes, insurance, interest during construction, return on investment required, and specific requirements for plants in the area of operation for the estimating companies.

The utility usually expects to earn a minimum of 20 percent return on investment on its equity portion. The exploration and producing investors have learned that a minimum acceptable rate of return on investment for their portion of the projects is 20 percent return on investment. The average conventional energy venture (nongeothermal) usually obtains about twice this rate of return to compensate for the risks involved.

The return on investment for the developer is most sensitive to the price received for the energy. Next to reliability of supply, the utilities' desires to use geothermal energy in electricity generating systems are dependent upon its price being low enough to make its use worthwhile. Much like coal and uranium, geothermal fuel prices will be a negotiated price between the supplier and the user. Each field will have significant differences in design so a uniform price cannot be expected for construction of the production facilities, or construction of the utilities conversion plant.

The nature of the reservoir geometry and the ability of the reservoir to respond to changes in production, rates, and temperatures will determine the final costs for producing electricity from each geothermal project.

The basic structure of price must provide an attractive rate of return to the prospector. To achieve this, the prospector's risk capital investment and time at risk before income must be minimized. Most important, the revenue should reflect the actual value of the energy sold.

Cost Comparisons - The cost comparisons between the various sources of energy that will be available and useable for electricity generation during the next decade will affect the rate of geothermal energy's growth. The economic desirability of the production or use of a fuel is sensitive to its price. Regulatory requirements have direct effect upon production and construction costs. The tax treatment for each fuel system is a dynamic one. This makes it very difficult to assess the resulting economics.

The amount of money needed to construct and operate plants to use each fuel is a strong component of how much the electricity producing customer will pay per unit of fuel. The average coal and oil burning plant uses 8,500 to 10,500 Btu/kwh. A nuclear plant uses about 14,000 Btu/kwh. Geothermal plants use between 21,000 to 33,000 Btu/kwh.

Oil - Electricity produced from oil fired plants is directly related to the cost of low sulfur fuel oil. An oil fired turbine generator plant costs between $385 to $400 per kilowatt. A combined cycle plant is about $300 per kilowatt. The difference in heat factor, operating cost, and available capital for these plants establish which will be used for meeting the increased demand and plant replacement schedule within a utilities service area. The estimated cost developed by Stanford Research Institute of fuel oil in mills per kilowatt hour is approximately 23 mills per kilowatt hour. Strong competition between suppliers results in a stabilizing effect upon the overall price of oil. Utility planners have estimated the range of price of oil to be 20.5 to 21 mills per kilowatt hour. These cost ranges combined with the new plant costs will produce electricity between 33 and 44 mills per kilowatt hour.

Coal - Coal prices are related to specific sources of supply and dedication of specific sources of coal to certain plants. Coal does not presently have the wide range of usefulness that oil enjoys today. This limits the substitution of one coal for another.

The price of steam coal and plant construction costs to meet environmental requirements result in an estimated price of 35 mills for electricity generated in new coal plants. Fuel suppliers currently estimate coal can be delivered within a 1,000-mile radius for 9 to 10 mills per kilowatt hour if surface mining methods are used.

Nuclear - Nuclear fuel plants appear to offer the least expensive electricity for a non-indigenous source of energy.

The utility industry estimates they will be paying 6 to 6.5 mills per kilowatt hour for nuclear fuels and plant costs in 1977 dollars will be $800 to $1,000 per kilowatt. The estimated cost of electricity from such plants will be between 32 to 34 mills per kilowatt hour.

Geothermal - Comparison of conventional electricity prices with geothermal steam prices is a matter of public record. This is the least expensive of all thermal systems employed in the United States. To obtain a comparison of hot water flash steam plants, it is necessary to use developments outside the United States for performance factors. Economics of hot water flash to steam projects continue to be impressive. Cerro Prieto's development is very encouraging as exploratory work confirms this development can exceed 500 MW. The improvement in heat recovery with double flash units would reduce the cost of electricity and increase the size of reserves significantly. Seventy-five megawatts have now been developed and work is underway on the next 75 megawatts. The first unit of 75 megawatts was developed for $264/kw and produced electricity for approximately $.008, tax free. Today, costs would be about twice that amount. The cost includes the well field operation as this is an integrated operation. It is estimated the second 75 megawatt plant will produce electricity for about 16 mills, tax free.

It is possible to use the development work now in progress at Momotombo, Nicaragua, to evaluate the costs of developing a hot water flash field today. DeGolyer NcNaughton, the international consulting firm, and Herman Dykstra, a reservoir engineering consultant, have completed examination of all the field test data from Momotombo. Tests using bottom hole pressure devices in selected wells were combined with field flowing tests. The firm concluded that double flash turbines could produce 96 megawatts for more than 30 years using the portion of the reservoir developed. Subsequent completion tests have demonstrated more than 100 megawatt capacity.

Turbine specifications being prepared are to have a plant turbine with 80 psig first stage and 20 psig second stage. The power plant for this 225^{o}C field may have two 35 megawatt units in operation by mid-1980. The estimated cost for the electricity generating plant installed will be $460 per kilowatt. A savings of $26 million in foreign exchange would result from this development.

Steam - Geyser's steam price is about an inexpensive as geothermal energy can be produced today. The 1978 price of 16.5 mills per kilowatt hour is well below the competitive value of this energy. Twenty mills per kilowatt hour would be a price more nearly reflecting its actual value in an area using oil or coal for electricity generation.

PGandE's plant #15 is expected to cost $320 per kilowatt with provisions for H_2S treatment. This is an increase of 250 percent over the average of the 1961-1974 period. In the same period, the cost of electricity generated averaged about 5.6 mills per net kilowatt hour. 1979 operating costs will have increased the price to 25 to 30 mills per kilowatt hour.

Summarizing the preceding discussion on comparison of costs and resultant prices of electricity, we can tabululate oil, coal, nuclear versus geothermal as follows:

	Oil	Coal	Nuclear
Fuel mills per kilowatt hour	20-23	9-11	6-7
Plant $/kw	300-400	580-950	800-1000
Electricity Busbar mills/kwh	33-44	35-36	32-34

	Geothermal		
	Steam	Flash 450°F	Binary
Fuel mills per kilowatt hour	14.5-16	16-20	26-30
Plant $/kw	320	450-475	500-1000
Electricity Busbar mills/kwh	22.5-24	25-30	40-48

Reserve Estimates - With these competitive conditions and an idea of the required investments in plant and fields, we can estimate the potential reserves identified in relation to the proven reserve.

The proven reserves of The Geysers are now 908 megawatts. The potential reserves are another 1,100 megawatts. To infer that the hot water area surrounding the dry steam reservoir will produce waters that will be used in flash steam plants is reasonable. Inferred hot water flash reserve should be approximately 1,000 megawatts.

The proven reserves in the Imperial Valley are 400 megawatts. Potential reserves of Brawley, East Mesa, Heber, Niland, and Westmoreland total 1,600 megawatts. Reserves have been inferred with another 1,000 megawatts in these and similar anomalies within the province. Considerable work must be done on conversion systems, and deep drilling in the California portion of the Imperial Valley if another 5,000 megawatts are to be moved from the resource category into the reserve category in the next 20 years.

In the western Utah area Roosevelt is the only area with proven reserves. It appears that sufficient testing and plant design work has been completed to assign 80 megawatts to that classification. One hundred-twenty megawatt potential and 300 megawatt inferred reserves can be assigned to Roosevelt on information now available. The remainder of that general area including Cove Fort-Sulfurdale, Thermal-Black Mountain, should have 1,000 megawatts potential reserves and 500 megawatt inferred.

Testing of potential areas in Nevada has not progressed to the stage where proven reserves can be assigned. The potential reserves of Phillips' three areas, and Chevron's two areas in the northern half of the state indicate 400 megawatt reserve. An additional 600 megawatt can be inferred on the basis of drilling data being extrapolated with geophysical surveys. With continued confirmation success in the Carson sink area, an additional 500 megawatts could be moved from resource to inferred reserves. New Mexico's Valles Caldera is considered as having 100 megawatt potential reserve. From the size of the anomaly and the temperature indicated by surface springs, an inferred reserve of another 300 megawatts should be assigned. This area has a total reserve of 400 megawatts.

Summary

Electricity Generation Reserves

	Proven (Measured) MW	Potential (Indicated) MW	Inferred (Geol-Geoph) MW
The Geysers	910	1,100	1,000
Imperial Valley	400	1,600	1,000
Coso-Lassen Long Valley, Mammoth Randsburg			700
Roosevelt	80	120	300
Cove Fort Sulfurdale Black Mountain-Thermal		400	600
N. Nevada		400	600
New Mexico		100	300
Alvord Area		200	100
Alvord to Vale			300
Subtotal	1,390	4,500	5,200
Total	11,100 megawatts		

The direct use of geothermal heat in the United States is on a local project basis except in Klamath Falls, Oregon, and Boise, Idaho. Local greenhouse operations, individual processing plants in industrial and agricultural projects, are found throughout the western United States, Alaska, Texas, and the southeast Appalachians. It is estimated these present direct uses represent proven reserves of 35 megawatts.

Reserves cannot be assigned to geopressure-geothermal projects. It is hoped the government research work in progress can develop sufficient data to provide inferred reserves in 20 years.

An oil accumulation to provide 164,000 barrels per year for 30 years would require 4.9 billion barrels to be available for production. Consider that less than 0.2 of 1 percent of all wildcats drilled in the United States during the last 4 years discovered producible reserves over the life of the field greater than 1 million barrels of oil.

To assess the impact of the development of this reserve now identified plus the stimulus such development will give to exploration requires an assumption that the governmental agencies believe indigenous sources of energy are necessary to the economy of the U.S.A.

Stanford Research Institute, The University of California, Riverside, and Science Application Inc. have each provided thoughtful studies on the effect of tax incentives for the development of geothermal resources. The effect of such tax treatment has been focused on the resulting price of electricity or upon how much income this sould "shelter" for the producer.

Each study has sidestepped critical questions of: How large a capacity can be economically developed from recognized prospects with the subject incentives? How many would be developed lacking such economic stimuli? What is the flow back to the government agencies in tax revenues if certain incentives are initiated? This demands careful analysis of the possibility of reduced tax flow from projects that are certain to be developed without the incentives versus the increased tax revenue from those projects that would not have been developed without the incentives.

Consideration of the dynamic effect of taxation regulations on an incipient industry will show a tremendous benefit to government agencies in increased tax revenues. Robert Rex prepared the following illustration demonstrating the flow of moneys to federal, state, and county agencies for a single 48 net megawatt project on federal lands.

ESTIMATED GOVERNMENT REVENUES

FROM FIELD DEVELOPMENT PROGRAM

EAST MESA 48 MW PROJECT

Ten percent federal royalty payments	$ 70,200,000
Federal income taxes	67,110,000
State income taxes	16,590,000
Ad valorem taxes	59,700,000
	$213,600,000

ASSUMES 25 MILLS/KWH - 30 YEAR PROJECT LIFE - 6 PERCENT ANNUAL INFLATION RATE

If the reserves now known on federal lands are developed, additional ones will be added in the process of development and by the increased exploration attracted to the area of successful development. Five thousand megawatts production on federal lands and 2,000 megawatts on nonfederal lands should return to the government $903 million in revenues each year over the first 30 years of the projects' lives. As royalty, $7.02 billion would flow to the federal government; $9.4 billion as income tax. About $2.3 billion would be allocated to the various states' income tax revenues and more than $8.4 billion to local county governments as ad valorem taxes.

Summary - In 1973 the geothermal reserves in the United States were 500 megawatts. Reserves identified since 1970 total about 11,100 megawatts. This is enough energy to supply the total electrical needs for 11,000,000 people. To generate the same electricity using fuel oil, 164 million barrels per year would be needed. Five billion barrels of oil would need to be discovered to supply the equivalent energy for 30 years.

Geothermal energy can compete with the other types of energy now being used in the United States. To do so, the energy must be available from its reservoir at a temperature above 400°F. Below this temperature, operating costs rise significantly as the number of wells to produce and reinject the fluid increases.

Tax incentives must be provided to encourage significant investment in the mid-temperature hot water resources if this type energy is to be developed.

The cost of the plants rises rapidly as the temperature of the reservoir decreases. The volume of fluid required to move through the system increases rapidly to supply the required heat. There are economic limits established by temperature that must be recognized. If the Btu content of a ton of coal drops, there is a point where it is not useable for power production. The same is true for oil and gas fluids as their associated water or inert gas ratio increases. Geothermal fluids quality and usefulness is also dependent upon the Btu content per unit volume produced. The building of power plants for mid-temperature projects is critical to the utilization of this large resource.

For this reason, it is difficult to present a specific cost of electricity produced by broad types of resource. The probable range of prices for electricity generated from steam and hot water reservoirs today is:

Steam 450°F and above		22.5 - 24 mills/kwh
Hot water flash -	below 400°F	36 - 50
	above 400°F	25 - 30
Binary		40 - 48

Research must continue on how to make fluids with temperatures below 400°F useful. The technology is now mature. There are vast quantities of heat in this resource awaiting the solution to the economic problems of using this low grade heat.

Risk capital must be readily available in units of $10 million to $15 million at the beginning of exploration. Development to 400 megawatts may require up to $100 million investment before payout of the first 50 megawatt unit is obtained. The investors with sufficient money to carry out a successful program will compare the return of invested capital offered by similar projects (utilizing similar technology and business know-how). The projects offering the best rate of return for similar risk and investment will usually be the ones selected for funding.

The biggest problem in obtaining risk capital is the uncertainty of the business. This includes the discrimination in tax treatment of hot water versus steam. This precludes being able to market the energy at competitive prices and obtain a favorable rate of return as other industries offer. Prospective investors should have assurance that government rules and regulations will encourage the discovery and use of this energy.

TECHNICAL AND ECONOMIC RISKS

IN GEOTHERMAL DEVELOPMENT

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The Technical and Economic Risks faced by both a supplier and a utility company in geothermal development are remarkably similar. Tables showing the major risks for each entity, as perceived by a supplier, are listed below. It was recognized that the distinction between a Technical and Economic risk is generally quite vague; as in most cases, the Technical Risks could be overcome if economic restrictions did not apply. For purposes of this paper, Economic Risks were limited to those elements most directly affecting economics such as pricing and taxes.

TECHNICAL RISKS

Supplier

Reservoir Life
High Salinity Fluid Problems
Hydrogen Sulfide
Lease Availability
Competitors Technological Breakthrough
Waste Water Disposal
Reservoir Exploration/Delineation

Utility

Reservoir Life
High Salinity Fluid Problems
Hydrogen Sulfide and other Environmental Problems
Cooling Water
Wheeling
Competitive Technological Breakthroughs
Loss of Alternatives

ECONOMIC RISKS

Supplier/Utility

Regulatory/Permitting Delays
Resource Price
Geothermal Tax Incentives
Increasing Capital/Operating Costs

The conclusion which can be arrived at by comparing the Technical Risks of the supplier and utility is that in most cases, both the utility and the supplier face the same risks with only a few exceptions; such as wheeling and cooling water being risks faced only by the utility with waste water disposal, lease availability, reservoir exploration and delineation being risks falling only on the supplier.

Capsule comments on each of the Technical Risks and their impact on the respective entities are as follows:

* Reservoir Life.

  The risk of a premature reservoir depletion is shared by both the utility and the supplier. The utility companies appear to have a dual concern; that is, they are fearful of not being able to amortize their plant investment prior to reservoir depletion and they are concerned about an electrical power supply deficiency which could put them into default on their electric power commitments and obligations. On the plant amortization side, some type of reservoir insurance, such as the penalty clauses commonly used in The Geysers area, offers a partial solution. However, since the supplier's investment is also very high and approaching that of the utility company's in some cases, the validity of having the supplier shoulder the entire reservoir life risk for both parties is subject to challenge. Since some utilities on occasion actually engage in lease acquisition, geology, geophysics, and other exploratory type high risk activities for energy sources, the logic of their not wanting to take any financial risks in regards to reservoir life seems inconsistent. On the power demand supply side, it would seem that an insurance type pool of geothermal power supply by a number of utilities would offer one method of reducing the impact of a premature reservoir depletion on any one specific utility. The feasibility of forming a geothermal power supply risk pool should be investigated.

* High Salinity Fluid Problem.

  The technical problems caused by high salinity fluids with the associated scaling and corrosion problems impact both the supplier and the utility. Additional R & D is required and higher capital and operating costs will undoubtedly be incurred by both the supplier and the utility in resolving the problem.

* Hydrogen Sulfide and Other Environmental Problems

The utility's hydrogen sulfide problem centers around the noncondensible gases exiting from the condenser and cooling towers during plant operation. The current preferred solution appears to be the installation of a Stretford type unit which should resolve the problem but not without extra capital and operating costs. The supplier must deal with hydrogen sulfide emissions at the wellhead and at the steam relief site when the turbine is shut down. To comply with forthcoming air pollution regulations, the supplier must either install a rather sophisticated automatic well control throttling system permitting rapid curtailment of production or employ a large labor force to manually accomplish the same objective. The former solution involves high capital costs while the latter involves high operating costs. Another solution available to the supplier is chemical down-stream abatement for which current technology appears to be developed but not tested on the large volume scale required; also, it would have high operating costs (hydrogen peroxide chemicals) and pose a number of transportation, storage and safety problems. An alternative solution for both the utility and the supplier would be an up-stream hydrogen sulfide abatement system which would remove the hydrogen sulfide from the steam prior to entering either the power plant or the steam relief site. A proposal to install an experimental unit of this type using the EIC process has been developed. Noise and water pollution are other environmental problems which at least in The Geysers appear generally controllable at acceptable costs.

* Competitive Technological Breakthroughs.

The risk of a new source of energy supply becoming available at a much cheaper cost is a risk to the supplier in geothermal prior to plant construction, while it is a risk for the utility company after the plant has been completed. However, the energy needs of the country and the anticipated costs are such that the relatively small volume of geothermal energy commercially available in relation to the country's total energy requirements significantly abates this risk. Also, there is always the possibility of comparable technology developments within geothermal for both the supplier and the utility company to become more efficient. That is, the supplier should be able to develop more effective G&G tools, develop ways of increasing well productivity, reduce drilling costs, and improve the reliability of down-hole hot water pumps. The utility can develop more efficient heat exchangers, better pumps, more efficient condensers and cooling towers, etc.

* Cooling Water for Utilities and Waste Water Disposal for Supplier.

Lack of adequate cooling water in some areas can be a critical problem for utilities while the disposal of waste water, generally required by the supplier, can be rather expensive. The supplier may also have a water supply problem if 100 percent reinjection is required for subsidence purposes.

* Wheeling

This is generally considered to be a utility problem only although, without wheeling, the existence of competitive buying would not exist in many areas. There is legislation which seems to mandate wheeling under some circumstances but without voluntary cooperation between utilities or additional legislation, delays in working out an equitable and economically feasible solution may be quite lengthy.

* Lease Availability

This is a supplier problem. It should be noted that delays in the issuance of Federal and State leases have significantly restricted the rate at which geothermal development is proceeding.

* Reservoir Exploration/Delineation

This is a supplier's risk which starts with the initial expenditures in leasing, geology and geophysics, and continues on through the drilling of an exploratory well plus generally at least two delineation wells. In some cases long term production tests may be required which in turn may require the drilling of an injection well. The level of risk at each phase of such a program changes but the total investment required before all phases of this program have been completed is generally quite significant and is all front-end money. The impact of this early investment, which then must await contract negotiations, long permitting delays and long construction delays, severely impacts the project's ultimate economics which in conjunction with the high risk element involved mandates the receipt of an equitable price for the resource.

* Loss of Alternatives.

This utility nonrisk factor is listed to point out that environmental or political restraints which would prohibit the expeditious exploration/development of alternative energy sources or even the continued operation of existing coal, nuclear, oil or gas fired plants would enhance geothermal which is less sensitive environmentally.

Capsule comments on each of the Economic Risks are as follows:

* Regulatory/Permitting Delays.

  Although this is a common problem, the economic impact of these delays is more severe on the supplier because of his front-end early investments. The initial environmental documents (EIR/EAR), Authority to Construct, Grading Permit, Site Supplement, Plant Certification, etc., all can cause considerable time delays which in conjunction with extended plant construction times result in an extremely long time delay between the supplier's initial investments in leasing/G&G/exploratory wells and the on-stream date of the plant (AUSA/ PGandE Unit 13 - 12 years). The impact of this type of a time delay on the supplier's economics is devastating. The effect of permitting delays on utilities is not quite as onerous economically since most of their investment takes place after most of the permitting delays have occurred. However, the utility may be unable to meet their power demand schedule because of such delays.

* Geothermal Tax Incentives.

  In order to expedite geothermal development, more substantial tax incentives are considered necessary. These should be in the form of more substantial tax credits for both utility and supplier, intangible drilling cost write-off provisions, and minimum depletion allowances of 15 percent. The Senate's version of a proposed Geothermal Tas Bill would permit depletion allowances of 22 percent through 1980 scaling down to 15 percent by 1984, the right to take intangible drilling tax write-offs, and apparently a 10 percent investment tax credit on tangible investments. The latter should be raised to at least 15 percent.

* Increased Capital/Operating Costs.

  Rising cost trends for both the utility and the supplier are having a substantial impact on project economics. For the supplier, inordinate increases in drilling costs, partly due to a rig scarcity, have been the biggest factor while higher leasing/pipeline and well completion costs have also had their impact. The utilities have been hit by substantially higher capital costs in the construction of plants and power transmission lines. Both the supplier and the utility suffer from the higher capital and operating costs associated with ever more stringent environmental requirements.

* Resource Pricing.

  Within the U.S. at this time there is only one area - The Geysers - where a geothermal resource is being sold for power generation purposes. The typical sales contract in that area is considered highly discriminatory to geothermal in regards to alternative energy resources. This may be understandable to some extent because when the sales contracts were negotiated, a buyer's market existed because of the large amount of hydro power available, relatively cheap gas and oil and the apparent attractive economics of nuclear power generation. However, that situation no longer exists and the cost of developing new geothermal resources has risen considerably, making higher prices for geothermal resources a necessity.

  In proven dry steam areas with reasonable development costs (under 6,000 foot wells) the current type pricing may be considered acceptable. However, in all other areas and especially where exploratory risks are high and well development costs are higher due either to deeper wells or lower productivity wells, more competitive pricing is an absolute necessity to support a higher level of geothermal development.

  Geothermal energy can currently compete with alternative fuels when it is of high quality; that is, either dry steam or high temperature/low salinity hot water resources producible at high individual well rates from reasonable depths. It is believed that within the next few years, lower quality geothermal reservoirs will be able to compete with alternative energy sources but only with adequate tax incentives and competitive pricing.

ANALYSIS OF ECONOMIC RISK ASSOCIATED WITH THE DEVELOPMENT OF A GEOTHERMAL FIELD

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Abstract. The resource developer of a geothermal field faces a number of uncertainties. During the exploration stage, the size and character of the reservoir are unknown. Even after development drilling is underway, there is continuing economic uncertainty. This paper analyzes a hypothetical field development case to determine the effect of four key parameters on cash flow and return on investment. The parameters are: (1) tax treatment; (2) geothermal fuel price; (3) drilling costs; and (4) operating costs. This study does not include site-specific reservoir parameters, but rather is intended to provide a broad overview of the developer's economic perspective. A sensitivity analysis is applied to each variable, and a probabilistic analysis is used to predict the range of the discounted cash flow after taxes. The results suggest that hot water geothermal resources currently bear a disproportionately large tax burden. We believe that this is the primary reason for the slow rate of development of the hot water geothermal resource even though the technological risks have decreased substantially in the past decade.

Introduction. The philosophy of geothermal resource development is directly comparable to off-shore petroleum exploration, as well as oil shale and tar sands development, because of the high initial investment and lag time before benefits are forthcoming. A geothermal resource developer typically invests his capital over a time of five years or more before income flows from the sale of steam. During this time he faces many of the same economic uncertainties faced by the oil and gas developer. These include uncertain projections of drilling costs, operating costs and anticipated tax treatment. In addition, he has the further uncertainty that his steam or hot water product has no established market price, except in a few areas such as The Geysers.

The purpose of this paper is to examine each of the above parameters and to estimate a reasonable range of uncertainty about a mean or expected value. Sensitivity and probabilistic techniques are then employed to show the effect on the "bottom line," which is cash flow or return on investment. The resource model used is that of a hypothetical hot water reservoir in the United States, for which lease acquisition begins in 1978 and power-on-line is achieved in 1983. Figure 1 illustrates the field development schedule and costs. This "average" case does not include the site-specific reservoir and/or developer characteristics which may greatly alter the true economic conditions and which must be examined before actual decisions are made; e.g., solids content, temperature, depth, non-condensable gas content, or certain technological risks. Furthermore, a few fields may be more economically attractive than this average case - and many more are less attractive. This study, therefore, focuses on the possible reasons the geothermal industry is so slow in developing commercial applications for the bulk of this resource. The assumptions made in the model include:

- U.S. tax code
- moderate temperature reservoir
- five-year exploration and development period
- no financing costs
- no exploration risk
- project stands alone for tax purposes

Economic Model. An economic evaluation model for the 50 Mw (net) field development schedule was formulated utilizing a general purpose economic cash flow analysis system with sensitivity and probabilistic calculation (Monte Carlo simulation) capabilities for use in the risk analysis. The specific economic cases considered herein are given in Table I. The base case provided an estimate of the economic feasibility of the project by utilizing average estimates of the costs and fuel price dependent on the latest information and experience.

Figure 2 illustrates the probability distributions applied to the four parameters: tax treatment, fuel price, cost of wells and capital, and operating costs. The prediction of the tax treatment presents a particularly difficult problem. The government tends to treat the geothermal industry more as an extension of the oil and gas industry rather than as a separate, unique entity. The probability of the tax laws being changed was given an equal chance; therefore, the results are presented in terms of two cases based on the tax laws: Case I - the current tax treatment, and Case II - the proposed tax treatment. The geothermal fuel price is expected to escalate at 4% per year; in addition, a triangular distribution of probability is applied which assumes the level of uncertainty is increasing. A similar triangular distribution is assumed for the cost of the wells and capital with a 6% escalation factor. A normal distribution is assumed for the operating costs.

Sensitivity Analysis. The sensitivity analysis performed on the field development economic model determined the effect of the four parameters on the cash flow and return on investment. Figures 3 through 6 show the results in general terms based on the most likely single-value results; i.e., single values for the fuel price, cost of wells and capital, and operating costs. The maximum and minimum values for the variables are ± 20% of the most likely single value.

As can be seen, the uncertainty of the fuel price and cost of wells and capital results in a most profound effect on cash flow. This is particularly significant to the small developer in the geothermal industry and, therefore, he must exercise more control over these project factors and utilize detailed project planning to reduce the uncertainty.

The comparison of the tax treatment cases are shown in Figures 7 and 8. The proposed tax treatment results in the developer receiving a greater return on his investment with a corresponding reduction in funds going to the government. This change could have a great impact on the development of numerous geothermal resources now considered uneconomic.

Probability Analysis. A probability or risk analysis was then applied to the cash flow calculations which involves the uncertainty expressed in the input variables. Since it is usually true that data are uncertain, then the notion of using risk analysis calculation seems to make more sense than simply guessing at values for the input data.

A risk analysis calculation amounts to assigning distribution functions to each input variable which is uncertain (Figure 2). These functions reflect the degree of knowledge associated with the variable, rather than a single value which is an assumption of certainty. The distribution function of each variable defines the range of likely values for the variable and the likelihood of obtaining particular values. In this study, the functions are expressed as percentages of the base case value.

The risk analysis is then calculated by a process called Monte Carlo simulation. This amounts to making the calculation over and over with different sampled values for each of the input variables. This is done in such a way that the more likely values of the input data occur more frequently than other values. After many repeated calculations (usually several hundred), the sampling of the input variables closely matches the distributions specified.

Naturally, the repeated calculations in the Monte Carlo simulation process do not obtain only one result. Rather it obtains as many results as Monte Carlo trials. The answers, then, are distributions of particular results such as profit, present worth profit, rate of return, etc.

As output from the probability analysis, we get a distribution curve for each single-valued result; e.g., cash flow and rate of return. Figure 9 shows the distribution curve for the present worth of after tax cash flow. As can be seen, there is a 50% probability that this project will make less than $14,000,000. The above analysis provides a feel for what ranges of profitability are likely to be obtained and the implicit risk associated with the project.

Conclusion. The technical and economic risks associated with a geothermal resource are significant factors for any development company but are particularly important for the small company. The technical risks can be assessed and reduced to some degree with added data and experience. The economic uncertainty, however, depends on many factors normally beyond the control of any single company. While this type of risk analysis tells little about whether a single project will be profitable, it does greatly assist in determining the value of several projects or a large number of projects. Consequently this approach is useful in evaluating the impact of changes in tax burden on the development of the geothermal resources in the U.S. This analysis of a hypothetical hot water geothermal field development project indicates that the developer faces economic uncertainties which restrict the commercialization of many hot water reservoirs, the primary factor being the large transfer payments in the form of taxes.

As it stands now, the average hot water geothermal field has trouble generating a present worth sufficiently large to justify the risk of the needed resource investment. That means that only a few of the more economically superior projects will be developed and/or there must be risk sharing by the public sector (i.e., the beneficiary of the transfer payments) by utilization of the Public Law 93-410 Loan Guaranty Program. It also means that if the tax burden were reduced, loan guaranties would not be needed.

DEVELOPMENT SCHEDULE AND COSTS
50 MW NET POWER PLANT

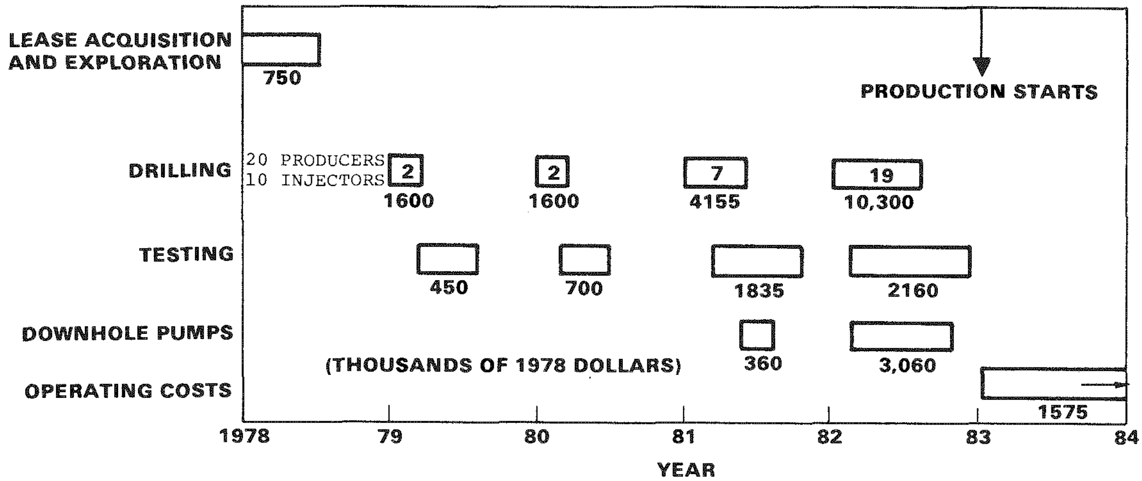

Figure 1

PROBABILITY ANALYSIS
PROBABILITY DISTRIBUTIONS

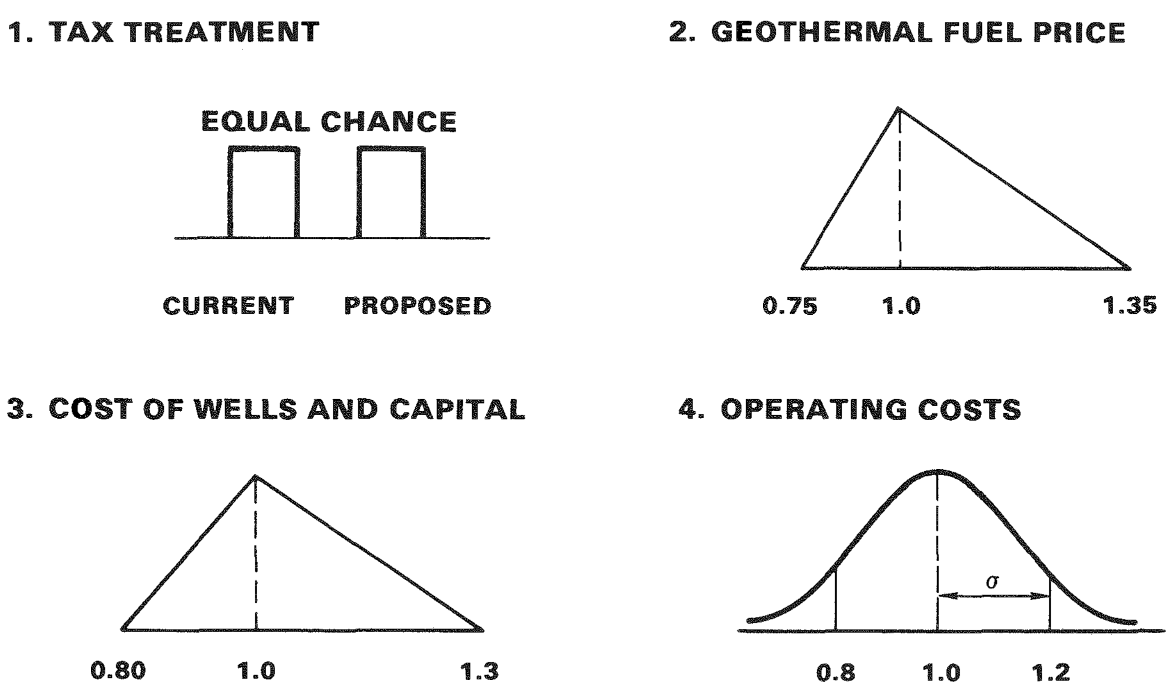

Figure 2

SENSITIVITY ANALYSIS FOR PRESENT WORTH AFTER TAX CASH FLOW AT 10% DISCOUNT RATE

CASE I — CURRENT TAX TREATMENT

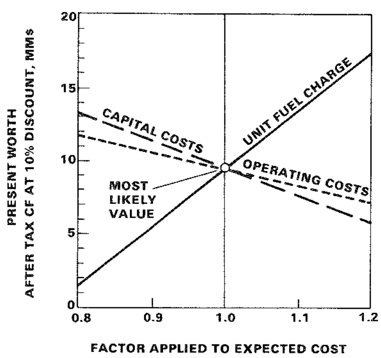

Figure 3

SENSITIVITY ANALYSIS FOR PRESENT WORTH AFTER TAX CASH FLOW AT 10% DISCOUNT RATE

CASE II — PROPOSED TAX TREATMENT

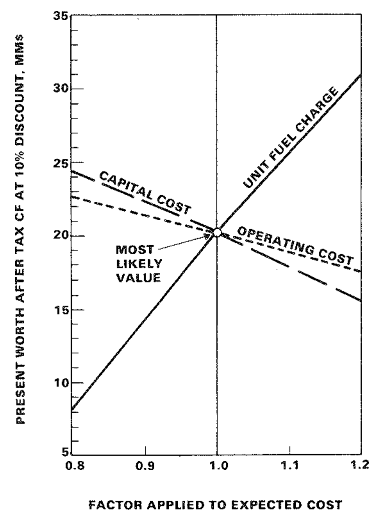

Figure 5

SENSITIVITY ANALYSIS—BEFORE TAX DCF RATE OF RETURN

CASE II — PROPOSED TAX TREATMENT

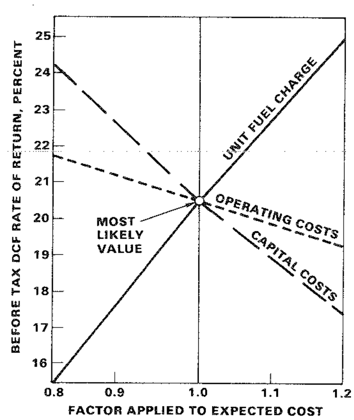

Figure 4

SENSITIVITY ANALYSIS—AFTER TAX DCF RATE OF RETURN

CASE II — PROPOSED TAX TREATMENT

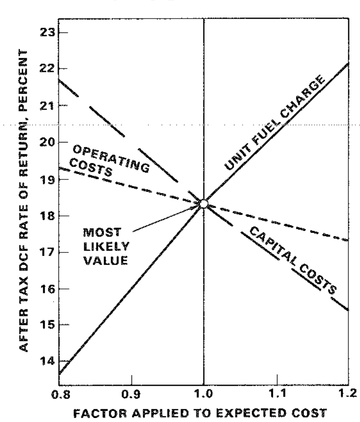

Figure 6

DISTRIBUTION OF REVENUES FROM 50 MEGAWATT GEOTHERMAL FIELD

CASE I — CURRENT TAX TREATMENT

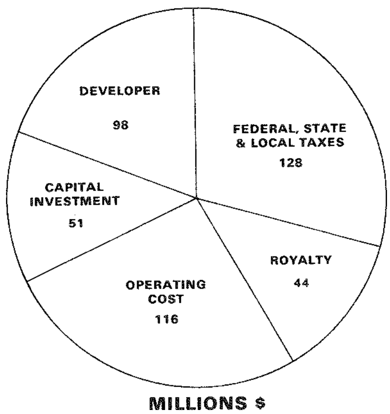

Figure 7

PROBABILITY ANALYSIS FOR 50 MW NET GEOTHERMAL FIELD DEVELOPMENT ECONOMICS

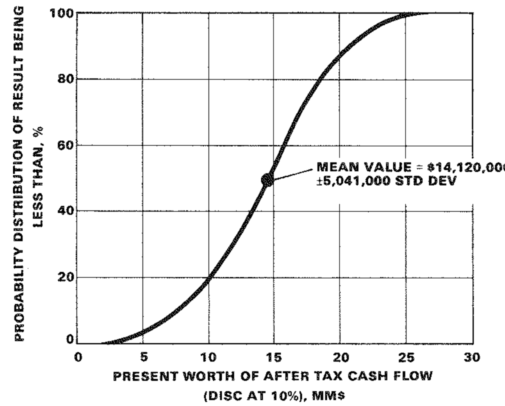

Figure 9

DISTRIBUTION OF REVENUES FROM FIELD

CASE II — PROPOSED TAX TREATMENT

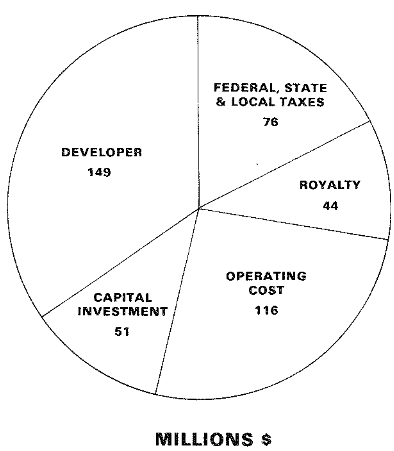

Figure 8

<u>TABLE I</u>

<u>Economic Model</u>

50-Mw Net Power Plant
Development begins in 1978
Power-on-line in 1983
Wells - 20 producers, 10 injectors
Federal and state income taxes = 52.7%
Royalty payments = 10%
Depreciation is calculated using double declining balance method with 11-year life
Costs escalate at 6% per year
Fuel price escalates at 4% per year

<u>Case I</u> - <u>Current tax treatment</u>

Investment tax credit = 10%
Ad valorem tax = 7% (effective)
No depletion allowance
No intangible capital deduction

<u>Case II</u> - <u>Proposed tax treatment</u>

Investment tax credit = 20%
Ad valorem tax = 3% (effective)
Depletion allowance = 22%
Intangible capital deduction allowed

GEOTHERMAL DEVELOPMENT: RISKS AND INCENTIVES

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Introduction An earlier paper in these proceedings presents my summary of the status of geothermal development in California and some State actions to encourage commitments to construct geothermal power plants. This paper focuses on a proposal I am submitting within State government for findings by the Public Utilities Commission that would stimulate electric utility commitments to construct the first few 50 MW size hot water geothermal power plants.

Why Take the Risks of Geothermal Development? This session deals with the risks of geothermal development as seen from various perspectives: geologist, resource, company, utility, government and public interest group. I want to begin by reminding us all of the reasons why the risks are worth taking. I do this from my perspective as a staff member of an agency charged with encouraging the maximum, acceptable development of geothermal energy resources in California. My agency, the California Energy Commission, is also charged with planning for an adequate, acceptable supply of electricity to meet the state's future energy needs.

From this perspective geothermal energy development presents California with a means of utilizing an abundant domestic resource. I have previously used 20,000 MW as an estimate of future geothermal electric generating capacity in California. Even if the resource actually proved by deep drilling turns out to be only a quarter of this value, the potential for avoiding the problems associated with developing 5,000 MW of oil, coal or nuclear generating capacity warrants incurring the risks associated with a small number of 50 MW hot water geothermal power plants. I have elaborated briefly on questions of resource estimates and environmental benefits in two other papers in these proceedings. Because of these potential benefits and because the Energy Commission is charged with planning for future electricity supplies, the Commission shares with the state's electric utilities the need for operating experience with commercial-scale hot water geothermal power plants. We need this experience soon. Decisions are now being made regarding electric power plants that will come on line after 1985, the very same time frame within which rapid expansion of geothermal power production could take place if the first plants prove successful.

First Round versus Second Round In defining and addressing the issues of geothermal power plant risks and incentives, it is useful to distinguish between the first and second rounds of commitments to power plant construction. By "first round" I refer to the commitments that must be made without the benefit of observing another geothermal project employing about the same technology in about the same physical and economic environment as the proposed new power plant. The primary risks to be resolved by first round commitments are those associated with technology and economics of basic construction and operation of the power plant and supporting geothermal field. Second round commitments are those that expand geothermal power production based on knowledge of what has happened in other situations that are substantially the same. The primary risks associated with second round commitments include reservoir reliability for larger scale development (say 200 MW or more, in contrast to the first 50 MW plant) and environmental/regulatory acceptance.

Incentives for the First Round I have proposed a goal of three 50 MW hot water geothermal power plants as first round commitments in California. Operation of these plants would provide experience in using hot water geothermal reservoirs for extraction and injection of fluids at a scale appropriate for commercial power plants. Three plants should provide a diversity in resource and power plant types and a scale of operation needed as a basis for expansion in the Imperial Valley to 500 MW or more in the mid-1980's, as shown in Table 2 of my preceeding paper, "Geothermal Power Plant Commitments in California." These plants would be used to prove, test and improve the technology and would provide the operating experience for the second round commitments. As a result there will be less uncertainty at the time of second round commitments. Another important result of the first round, if the plants are successful, would be a substantial increase in the incentive to find new resources, i.e., to perform the exploratory drilling that will eventually determine whether California has a 5,000 MW, 20,000 MW or 30,000 MW geothermal resource base.

Actions that will cause or substantially encourage commitments to construct the first round of 50 MW hot water geothermal power plants include the following: (1) Private companies decide to build plants independently of any sharing of the risk by government; (2) The Federal government cofunds demonstration power plants; (3) The Federal government guarantees loans that enable power plant projects to be financed by resource companies, utilities or other entities; (4) State governments provide funds to share the risk of financing power plant projects; (5) State regulatory bodies, such as the California Public Utilities Commission (PUC), provide special cost or rate incentives or assurances to stimulate utility commitments to geothermal electric power production. Because the most important new action that could emergy in California during the next year appears to me to be action by the PUC, I will describe only the last of the options just listed.

One reason for focusing on incentives achieved through actions by the PUC is that the power plant operator, rather than the resource developer, has the greatest need for special incentives to overcome the risks of commitment to a first round power plant project. The resource developers are accustomed to taking risks associated with finding and developing natural resources. Geothermal risks differ from those associated with many other natural resources, primarily due to the necessity of having a customer located in proximity to the resource. By providing incentives to the power plant operator and assuring that the power plant operator will be able to pay the resource developer an adequate price for his product, an incentive program directed toward the power plant operator will meet the primary needs of the resource developer.

Another consideration behind the incentive program being described here is the distinction made above between first and second round commitments. Because first round commitments must be made without the benefit of experience gained through construction and operation of other substantially similar plants, stronger incentives are appropriate for these commitments than for later ones. If the first round plants are highly successful, little or no additional economic incentive would be needed to stimulate expansion. If, on the other hand, the first round plants do not demonstrate that power production from some hot water resources can be made economically attractive or competitive, then strong incentives for further expansion would not be appropriate, even though "needed" to make the expansion occur. Therefore, incentives directed at obtaining commitments to build the first round of plants should be limited in scope to about 200 MW of generating capacity, i.e., limited to the first four hot water geothermal power plants built in California.

A third consideration in designing an incentive program for the first round power plants is to assure that the projects that result from the incentives do in fact provide information that enables subsequent power plant decisions to be "second round" commitments, i.e., commitments made in the light of knowledge gained from construction and operation of the first plants. This means that first round projects, especially any that make use of government incentive programs and/or public funds, should be structured to provide the geothermal community with the information needed to design lower cost projects for second or third round commitments.

Mechanisms for PUC Action Three substantial financial incentives that would cover risks of geothermal development could be promulgated by action of the Public Utilities Commission. These are:

* assured recovery and return on capital invested in geothermal power plants

* allowance for purchasing some geothermal electricity at higher cost than electricity from other competing sources

* allowance for substantial research and development costs to cover some capital and operating expenses of geothermal power plants.

The action most appropriate for presenting the PUC with an opportunity to apply such incentives to stimulate construction of the first round of hot water geothermal power plants would be a joint proposal to the PUC by the Energy Commission, the Geothermal Resources Board, one or more electric utilities and some geothermal resource companies. The case for PUC approval would be based on considerations of geothermal energy as a preferred source for electricity production, equity in sharing risks of geothermal development and need for early commitments to build and operate hot water geothermal power plants.

Other actions could also be taken by the Energy Commission and others seeking to establish geothermal resources as a major component in California's electricity supply. These include the design and implementation of lesser incentives appropriate for second round commitments (e.g., reservoir insurance) and/or similar action directed at incentives especially appropriate for municipal utilities and the State's Department of Water Resources. However, I give these other incentive actions lower priority than the proposed three point agenda for PUC action. Therefore, I conclude this paper with an elaboration on the three ways the PUC could provide major incentives for utilities and others to incur the risks of the first plants.

First, through its authority to determine what investments constitute the base on which a utility earns an approved rate of return, the PUC could assure that capital invested in a first-of-a-kind geothermal power plant is as safe as that invested in any other project. Such assurances could be provided through PUC findings of a general, statewide nature or through the regular PUC certification of specific geothermal power plants. In either case the objective would be to assure the utility building the plant that the investment plus a reasonable rate of return would be recovered through the rate base regardless of the operating reliability that might be experienced with the plant. When coupled with some adequate arrangement for generating or purchasing replacement power if needed, this would amount to the equivalent of reservoir insurance as far as the utility need be concerned.

Second, through its authority to determine allowable expenditures for purchase of fuel or electricity, the PUC could allow a utility to cover expenses of purchasing electricity from a geothermal power plant at a cost that could be higher than other sources. The PUC could establish this as an incentive either through special hearings and findings on allowable expenses for stimulating geothermal development or through other, more regular, proceedings that determine allowable expenses of each of the regulated utilities. This provision for possibly high electricity costs would cover the utility when it is not the actual builder of the power plant but is the plant operator or the purchaser of electricity from the plant. When combined with a federal loan guarantee to a company, other than the utility, constructing a power plant, this incentive measure could effectively bring the utilities within the scope of the existing loan guarantee program without putting them in the position of having to default on a loan to activate the coverage of their risk. An additional benefit of an official PUC action of this type of incentive could be a finding by the PUC that a company can be a power plant owner and operator without being considered a utility and, thereby, being brought under PUC regulation.

Third, again through its authority to determine allowable expenditure, the PUC could allow a utility to expense as research and development those expenses of building and operating a geothermal power plant that are above what it would have to pay for electricity from other sources. This measure would combine aspects of the other two incentives by applying to either capital or operating costs or both, depending on the situation and the determination of what costs are above the normal and should, therefore, be attributed to the research and development efforts. This and other incentives could be coupled with provisions to assure that both the costs and the information are shared among California utilities.

Conclusion The risks associated with first round power commitments are technical and economic and can best be overcome by financial support and economic incentives. Possible incentive measures that could be put into effect by PUC action have been described. Other incentive measures, including improved regulatory and environmental procedures and issue resolution, are discussed in a separate paper. Reservoir insurance is a possible incentive for expanded geothermal development after experience with the first round of hot water power plants. This is the subject of a separate section of these conference proceedings.

SOME TECHNICAL RISKS IN GEOTHERMAL POWER PLANTS

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Abstract Some technical risks involved in the design, construction and operation of geothermal power plants in liquid-dominated hydrothermal resources are described and their impact and potential resolution are discussed. The risks dealt with are those related to corrosion, noncondensible gases, instrumentation, water availability, and brine modification. These are evaluated as they occur in both a moderate-temperature, low-salinity brine (Heber, CA) and in a high-temperature, high-salinity brine (Niland, CA) and in two different type power plant cycles; i.e., a direct flashed steam and a pure binary, liquid-to-liquid cycle. The highest risks appear to be in the corrosion and instrumentation areas. However, they do not appear unmanageable and suggestions are made for their reduction. A number of other risk items, not discussed in this paper, are dealt with in a companion paper by others prepared for presentation in the same workshop.

Introduction and Summary Unknown or uncertain information causes technical risk areas which may govern the decision to design, construct and operate a geothermal power plant. In this paper, an attempt has been made to identify and analyze risk of major importance to decision-makers. Other risks, while of significance, are apt to be reflected only in general considerations regarding plant improvement or optimization. This paper, in large part, draws from a recent feasibility study performed under contract to the San Diego Gas and Electric Company (SDG&E) based on the SDG&E Geothermal Loop Experimental Facility (GLEF) at Niland, Ca. [1]. Accordingly, the high-temperature, high-salinity Niland brine was considered as one condition under which risks should be analyzed. Another Imperial Valley brine, that at Heber, was taken as representative of a moderate-temperature, low-salinity brine which would provide a contrasting set of risk conditions from Niland. Brine properties were considered to be the following:

Brine	Downhole Temperature	Total Dissolved Solids
Niland	500^oF	200,000 ppm
Heber	360^oF	14,000 ppm

To gain an indication of the effect on risks of different power plant cycles, risks for both direct flashed steam and liquid-to-liquid binary cycles were considered. Both because of the amount of information available, and the fact that high-salinity Niland brines create the more hostile fluid environment, this brine was taken as the "base case" for risk analysis. Direct flashed steam was considered the "base case" power cycle.

Since this paper has been prepared as a companion piece to one to be presented at the same session by another firm, only five major risks are discussed. Another five areas, also considered to be major risks, are discussed in the other paper. [2]. The risk areas considered in this paper are corrosion, instrumentation, noncondensible gas, water availability and brine modification. The other paper considers scale, two-phase flow, steam purity, waste disposal, and equipment.

The most important problems in the plants, and the major risks, stem from brine handling and are in the areas of scale and corrosion. Of the five risk areas discussed further in the following paragraphs, corrosion is considered to be a moderate technical and a high economic risk; instrumentation risks are high; and noncondensible gas, water availabilty and brine modification risks are low. All five risks are considered manageable and the discussion includes action in power plant design which may be taken to mitigate them.

Corrosion. This is an obvious problem area for metals exposed to fluids such as geothermal brines. The determinants of the corrosion problem include the characteristics of the brine, the nature of any brine modification undertaken and the power plant design. In the flashed steam cycle, corrosion in the vapor areas of the plant will be related to the efficiency of the steam scrubbers in preventing carry-over and, also, to characteristics of the brine, because of impurities introducted by carry-over.

In the GLEF, an equivalent of approximately one year's power plant operating time has been accumulated and both carbon steel and stainless steel portions of the plant have corroded significantly in both the brine and in the vapor. Because this experience is still limited, fully definitive data are not yet available, but the most severe corrosion appears to be in the form of both pitting and general corrosion in the carbon steel of the flash vessels. Stainless steel flash vessel lining material has also experienced considerable corrosion.

Pitting corrosion does not appear to be a problem in the scrubbers. However, the severity of general corrosion has not yet been established. The effect of air on the corrosion rate has not been identified but it does appear that substantial corrosion also occurs during air-free operation. Another uncertainty is just how much corrosion protection will be provided by scale. On the other hand, scale could enhance pitting. The United States Bureau of Mines recently reported the results of 30-day corrosion tests at Niland on coupons of several different metal alloys [3]. During these tests, carbon steel experienced general corrosion rates of 25 to 79 mils per year and pitting rates up to three or four times higher.

It is natural to assume that corrosion from less saline brines such as Heber will be less than at Niland. However, corrosion is not a well-defined problem at this time and, since its management could have a serious impact on plant profitability, it is rated as a high risk area.

In some conceptual designs of 30-year life power plants using Niland brines, carbon steel materials have been assumed for unmodified brines and corrosion allowances up to 5/8" used. Obviously, this allowance, chosen prior to the corrosion data just mentioned, will need further review, preferably with longer term data. Besides the obvious approaches of corrosion allowances and materials selection to solve the corrosion problem, the feasibility study, Reference [1], considered redundant flash vessel trains, which could provide some relief from the corrosion problem, as well as the scale problem for which primarily intended. The study indicated that, because of the resultant higher plant capacity factor, a design with a 50% capacity redundant train would actually provide about a 15% lower cost of energy than a simple 100% capacity design. On this basis, repairs which lead to a doubling of operation and maintenance costs, to 4.4 from 2.2 mills/kWh, would increase the energy cost by about 6%. This degree of increase should not seriously affect the economic feasibility of the design, but it remains uncertain, and an element of risk, as to whether this will be the amount of repair work required. In the long term the risk in the corrosion area should be mitigated by selection of suitable materials and development of operating procedures aimed at the minimization of corrosion.

Instrumentation At the GLEF, a flashed steam loop in a heavy scaling environment, the performance of instrumentation sensors in the brine stream has been a severe problem. This area is considered a high technical and high economic risk for future power plants. Thermowells at the GLEF have accumulated layers of insulting scale so thick that temperature readings have become invalid. Pressure taps have been sealed over and pressure gage diaphrams covered over with scale. Conventional flow measuring instruments including orifice plates have also been rendered useless by scale. At Heber, with a much less saline brine, the instrument sensor problems would be expected to be similar to Niland, but with a much lower degree of severity. By virtue of its being a closed loop on the brine side, a binary cycle should experience less precipitation of dissolved solids and so a lower scaling rate and a lower instrumentation risk.

The key to the instrumentation problem is, first, to use a minimum number of instruments and then, to select those types which do not depend on in-stream sensors. Where in-stream sensors are required, they should be placed in the most benign stream wherever possible, that is, in steam or other working fluid instead of in brine. In order to get out-of-stream flow sensing, ultrasonic flow meters have been used. Although they are entirely out-of-stream, they depend on an adequate transmission of the ultrasonic energy through the pipe, fluid and scale. In one case at the GLEF, the ultrasonic flowmeter has worked well. In another, the flowmeter appeared to be ineffective because of energy absorption caused by the thickness of the scale. However, tests of this type meter will continue, and a good prospect of their ultimate successful use exists. For pressure and temperature sensing in the brine stream, it appears that devices which enable operators to clean a tap, insert a sensor and then take a reading have a good chance of success. Devices available for this service include the "Strahman" hand operated sample valve and "Cosasco" access fittings. This method of getting data is laborious and does not provide continuous readings. Future improvements might include temperature sensing through pipe walls and the use of pressure data derived from flowmeter readings.

Water Availability At both Niland and Heber the availability of cooling water makeup could become a problem because of the competing demands of agriculture. For other sites it would be conservative to assume that a supply of good water is similarly not readily available. Steam condensate from a flashed steam plant could be used for makeup unless it is required for reinjection. With a liquid-liquid binary plant, of course, the condensate option is not available.

If it is necessary to utilize water which requires extensive treatment, the cost of energy will rise but there should be no question as regards technology. Accordingly, this problem is considered an item of low risk to plant success.

Noncondensible Gas The presence of noncondensible gases in the brine will strongly affect the choice of the power plant cycle. For a flashed steam cycle, excess gas will decrease turbine efficiency, require a larger, more expensive condenser and increase auxiliary power requirements associated with gas removal. At the level of about .5 weight percent of brine, a flashed steam plant is preferred. At a considerably higher level, which would require a study to ascertain, it would be more economical to use liquid-liquid binary.

If hydrogen sulfide is present in sufficient quantities to create a pollution problem, a cost impact for removal equipment occurs. Assuming that the Stretford process, which it is understood is now the preferred approach at the Geysers, would be used, an increase in energy cost of about 5 percent would be caused by the hydrogen sulfide at Niland.

At the GLEF, the noncondensible gas content has been assumed to be .5%, although recent observations have been as low as .1%, so a flashed steam plant is indicated. The hydrogen sulfide content has been assumed to be 820 ppm by volume, although observations have been both above and below this value. To ensure that air quality standards are met, the use of the Stretford process, or some equivalent system, would be assumed. As regards these two factors, the Heber site is not significantly different; noncondensible gases do not govern the choice of plant type and hydrogen sulfide removal is probably indicated.

An additional risk exists that the reservoir noncondensible gas quantity and type will change over the plant lifetime. The best way to have warning of this is to set up a program of reservoir and air quality observation and modeling. However, by providing a plant which is initially designed in a conservative manner, this risk can be reduced.

Since the risks associated with noncondensible gases can be mitigated by available methods at a fairly reasonable cost, both the technical and economic risks associated with this problem are classed as low.

Brine Modification Niland-type high salinity brines modified by the addition of acid have shown a decrease in scaling rate by as much as a factor of 10. However, there is an attendant disadvantage in the probability of increased corrosion from the acid. For Heber-type brines of lower salinity and, hence, less tendency to scale, there is less incentive to use brine modification. Likewise, for a binary loop with a closed brine circuit, there might be less incentive to modify the brine to reduce scaling.

At East Mesa, brine modification by the use of an organic inhibitor was effective in the prevention of some scales. Also, the use of colloids may be effective in preventing the formation of silica, the most pervasive of the Niland scales.

If unmodified, the spent brine may be processed through a clarifier and filter at the plant exit, prior to injection, to prevent scaling of injection lines and the wells. This process has been quite successful on a partial flow line at the GLEF and can be expected to be considered for future power plant design.

Brine modification may be an opportunity to improve performance and lower energy costs. However, the success of the plant is not dependent on brine modification, so the risk is low.

ACKNOWLEDGEMENTS

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GEOTHERMAL POWER PLANT DESIGN RISKS

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Introduction Recently, The Ben Holt Co. and Bechtel National, Inc. produced a joint report for San Diego Gas & Electric Company and the Department of Energy entitled "Feasibility and Risk Study of a Geothermal Power Plant at the Salton Sea KGRA." The Study was based upon the experience gained by operation of the Geothermal Loop Experimental Facility (GLEF) at Niland for the past two years. Since representatives of both companies are appearing at this meeting, the representatives elected to address different aspects of power plant risks in order to prevent a duplication of effort. Accordingly, this paper is concerned only with the following risks:

- Scale
- Two-Phase Flow
- Steam Quality
- Waste Disposal
- Equipment

The foregoing risks will be discussed as they relate to the hypersaline brine characteristic of the Salton Sea KGRA and the medium temperature low salinity brine characteristic of the Heber KGRA. These two cases cover the range of conditions that may be expected in a large number of liquid-dominated reservoirs. However, since each geothermal reservoir tends to be unique, applying the findings for these two reservoirs to others is in itself an additional risk. Risks associated with the design of binary cycle plants as well as steam flash plants will be discussed.

Risks associated with regulatory requirements and the reservoir are not discussed in this paper.

Scaling Scale deposition in equipment handling geothermal brines appears to be a universal occurrence. Each brine is more or less in equilibrium with the host rock and lowering of the temperature or changing the composition of the brine by flashing affects the solubility of the constituents. Experience at the GLEF indicates that a moderate reduction in temperature and accompanying increase in flashing results in the deposition of a scale containing predominantly heavy metal sulfides. As the temperature is lowered further, the predominant constituent of the scale appears to be silica. At Heber, the predominant scale forming constituents appear to be metallic sulfides and silica. Some reservoirs, but not the two under consideration, contain substantial quantities of carbonates which can form scale. Carbonate plugging of well-bores is a not uncommon phenomenon.

Last year at the Kah-nee-ta meeting, our firm reported the results of a 2,000 hour heat exchanger test at Heber [1]. This work was supported by the Electric Power Research Institute (EPRI) and the California Energy Commission. A small scale heat exchanger was designed and installed to simulate the conditions which would exist in the type of binary cycle heat exchanger proposed for a commercial unit. We found that steel tubes were a satisfactory material of construction and would be expected to last for thirty years. We found also that the fouling factors were well within normal commercial limits. At the hot end of the test unit, the calculated fouling factors were about 0.0006, increasing to 0.007 at the cold end of the unit. These factors were based upon the assumption that the heat exchangers would be cleaned once a year. The scale in the steel tubes was soft and could be removed by normal mechanical means.

Scale formation in piping and equipment other than heat exchangers is not expected to be a significant problem at Heber for a binary cycle plant where the brine is pumped and not flashed. Little is known about the scaling characteristics of Heber brines when flashed. One would expect an increase in scale formation as the TDS concentration of the flashed brine increases. We suspect that other liquid-dominated medium temperature, low salinity reservoirs will show scaling effects similar to Heber.

The scaling characteristics of the Salton Sea hypersaline brines are a different matter. Scaling rates of one mil per hour and higher have been measured in the GLEF. It should be recognized that the Salton Sea brines are unique and by no means characteristic of liquid-dominated reservoirs. In this connection, the Heber reservoir is much more representative of the KGRA's in the Western United States. The management and control of scale deposition and removal at Niland is the major remaining problem for which economic solutions are being aggressively sought at the present time.

After some two years of intermittent operation of the GLEF, scale experience may be summarized as follows:

* Some scale forms within the well bore, perhaps up to 1/2-inch near the surface. This scale can be removed by drilling.

* Some scale is formed in the production line between the wellhead and the plant. After two years, the thickness varies from 1/2-inch to 0-inch and can be removed by hydroblasting.

* After the first stage flash within the plant, and in some portions of the injection line, scale forms at rates of about one mil per hour.

Scale management and control is being aggressively pursued at the GLEF and the program for accomplishing such management and control has already been presented by an earlier SDG&E paper. One way to do this is by lowering pH of the brine to about 4, thereby inhibiting the rate of scale formation. Lawrence Livermore Laboratory's Industrial Support Program has shown this approach to be technically feasible.

The GLEF has now been modified to incorporate a two-stage flash system. One stage can be shut down for cleaning while continuing to operate the plant with the other stage. In this way continuity of operation will be obtained. Promising approaches for scale control include pigging of the injection line and hydroblasting of equipment.

We feel that technical and economic solutions to the severe scaling problems at Niland will be found in the ensuing months and that these solutions will be of general applicability. By contrast, scale formation at Heber for binary cycle plants is a low risk factor.

Two-Phase Flow In cases where the production wells are self-flowing, a mixture of steam and brine will be present at the wellhead. This two-phase mixture is then piped to the plant. Usually, the flow in the well is steady-state, because of the relatively high velocities normally existing. However, unstable and pulsating flow can occur in the piping between the production well and the plant. This unstable flow condition can cause a corresponding instability within the power plant. This phenomenon has been, and still is, a problem at the GLEF.

It is known that surging may be minimized by high velocities with accompanying high pressure drops. This may not be an acceptable solution because of the loss in temperature between the well and the plant. One way to handle the problem is to provide a wellhead separator and then transport the steam and the brine to the plant through separate lines. While this method should be foolproof, it is also expensive. Various schemes have been proposed for remixing the fluids periodically between the plant and the wellhead. Not all have been tried out, so we do not yet know the best answer. If the plant is located immediately adjacent to a production island, the problem would appear to be minimal. We judge the two-phase problem to be low risk, but annoying.

In cases where the wells are pumped, the two-phase flow does not exist between the production well and the plant. In cases where the geothermal brine is used directly in a tubular heat exchanger, no vapor is formed and two-phase flow is avoided.

Steam Quality It is important that geothermal steam, whether used directly in a steam turbine or indirectly in a tubular heat-exchanger, be of sufficient quality not to form deposits on the steam turbine or on the heat exchanger surfaces. Steam quality, in normal power plant parlance, refers to the amount of moisture in the steam. While this is an important consideration in geothermal power plant design, what we are really concerned with is reducing the particulates in the steam to a level where fouling of either the turbine or heat exchanger surface will not take place. This involves reducing the TDS content of the steam to 30 ppm or less. By contrast, there appears to be no advantage in reducing the moisture content in the steam less than 0.1 percent, or 1,000 ppm.

The seriousness of the problem varies with the reservoir. At The Geysers, for instance, commercial steam separators appear to be satisfactory.

Centrifugal type separators have been in use successfully in New Zealand, El Salvador and Mexico. These units have been used on moderate salinity brines. SDG&E tested this design in a pilot operation at Niland several years ago and compared its performance with a washing type (Hutchinson) scrubber which is now in operation at the GLEF. The performance and design of this scrubber at the GLEF have been described in the literature [2]. It is characterized by a low pressure drop (less than one psi overall) and a low enthalpy loss because of the low wash water rate. The TDS content of the steam during good operation is in the range of 10-30 ppm. Despite frequent upsets, no cleaning of the steam heat exchangers has been necessary after two years of operation.

The TDS content of the steam leaving the scrubber is not a function of the TDS content of the steam entering the scrubber, but rather reflects the purity and amount of wash water entering the scrubber. The TDS content of the purified steam can be made to approach zero, limited only by the purity of the wash water itself.

Thus, a satisfactory method of cleaning steam for use in heat exchangers has been demonstrated at the GLEF on a high salinity brine. Other satisfactory methods have been in use on low salinity brines. Therefore, we consider the problem of producing high quality steam to be low risk. We should point out, however, that no long range steam turbine tests have been made on steam produced from the Niland reservoir, so there is a possibility that an unforeseen problem could arise.

Waste Disposal The disposal of cooling tower blowdown is a general problem common to other types of power plants and many types of industrial installations. In the Imperial Valley it is probable that cooling tower blowdown can be disposed of in initial plants by discharge to the Salton Sea. A major geothermal development in the Valley will require the application of other methods of treatment or disposal of cooling tower blowdown. Reinjection would be a desirable alternative. We perceive little technical risk or economic risk for this alternative.

Obviously, in a great majority of cases, spent geothermal brine must be injected into the reservoir for safe disposal. Risks associated with injection of brine are covered by other speakers.

A special problem in the Salton Sea reservoir is the disposal of siliceous solids resulting from the removal of suspended solids prior to injection. It is anticipated that up to 25 tons a day of solids (dry basis) would be produced from a 50 MW_e plant at Niland. Disposal poses a problem in securing a suitable site. The problem does not exist at Heber and could exist in varying degrees at other sites where silica removal prior to injection is desirable.

Equipment

Steam Turbines Single entry steam turbines have long been used successfully in geothermal steam service. Double entry steam turbines are proposed and in use on some of the newer liquid-dominated reservoir plants. There appear to be no constraints to specifying double entry steam turbines for geothermal service, providing the steam quality is adequate.

Hydrocarbon Turbines For binary cycle applications, large 50 to 70 MW_e expanders are proposed, utilizing light hydrocarbons as working fluids. Both axial flow and radial in-flow designs have been proposed. The axial flow designs would be basically steam turbine designs modified to accommodate a different working fluid. The radial in-flow designs have been used for many years successfully in cryogenic service and hydrocarbon processing. While there are hundreds of these latter installations, none of them so far approach the size for a 50 MW_e plant. Because no large units of either type have been built and operated, many persons have perceived large hydrocarbon turbines to be a major risk item. The view of this writer is that they are a moderate risk item, because there is much experience in the operation of high pressure, high temperature compressors of this size. This experience should translate directly to the design of large turbines.

Pumps The pumping requirements in steam flash plants are no different than in any other power plant, and, therefore, low risk. Pumping requirements for binary cycle plants are characterized by the need to pump relatively large quantities of light hydrocarbons at fairly high pressures. The conditions are not extreme. While engineers may differ as to the particular configuration, there is little question that suitable pumps can be provided to do the job. These pumps have been developed over a long period of years for hydrocarbon services more severe than the ones proposed herein.

Heat Exchangers and Condensers It is probable that most steam flash plants will incorporate surface condensers rather than barometric condensers in order to control H_2S emissions effectively. From a technical standpoint, there is little risk involved in providing surface condensers for the service. Suitable materials of construction will be necessary, probably stainless steel, in order to resist the corrosive effects of H_2S and CO_2.

The large brine hydrocarbon exchangers required in binary cycle designs are state of the art. These exchangers would be built in accordance with TEMA Standards and would be fixed tube sheet design and single pass on both tube and shell sides. This type of exchanger has long been used successfully in the hydrocarbon processing industry. In order to do an effective design job, information must be available regarding the corrosion and scaling characteristics of the brine.

The transport properties of the working fluid are subject to some uncertainty in the critical region. While it would be desirable to develop better data, it appears that the present correlations are adequate to design with confidence. In this connection, it would also be desirable to develop better thermodynamic data in the critical region for use in hydrocarbon turbine design. EPRI is planning to obtain more precise data. In the view of this writer, the available data are adequate for the first demonstration plant. By this it is meant that a conservative design approach will be used. With better data, reduced costs would be expected.

The economic impact of a conservative design is expected to be minimal.

Hydrocarbon condensers are also state of the art and the technology is directly transferable common practice in the hydrocarbon processing industry. Thus, we conclude that the design of heat exchange equipment is low risk.

Control Systems Control systems for steam flash plants appear to be straightforward. There are steam flash plants operating successfully in several foreign countries. Our impression is that they are considered to be base-load plants in which the operating mode is similar to a hydroelectric project. If you want more power you bring additional wells on-line and vice-versa. Load shedding capabilities are provided for rapid shutdown.

Control systems for binary cycle plants appear to require no new technology; but proper attention needs to be paid to the different response characteristics embodied in large hydrocarbon turbines and in the relatively slow response characteristics of large brine hydrocarbon heat exchangers.

Because of scaling, much difficulty has been experienced at the GLEF in the measurement of control variables such as temperature, pressure and flow and in the operation of control valves and other valves in a scaling environment. A program for solution to these difficult problems is presently under way at the GLEF.

We conclude that control systems design for both types of plants at both locations is low risk, but that at Niland measurement of key variables is still a problem.

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RISK OF GEOTHERMAL DEVELOPMENT

FROM A UTILITY VIEWPOINT AND ASSOCIATED

CONTRACTUAL CONSIDERATIONS

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This paper is presented from the viewpoint of an electric utility which is functioning in the capacity of a purchaser of geothermal energy produced from a liquid dominated geothermal system. This approach is taken because most new commercial development in the United States will be from such a system, and it is assumed that most purchasers will not maintain a resource ownership position.

There are four basic areas of risk to be considered:

- risk related to the resource itself
- risk related to operations by the producer
- regulatory risk
- risk of public action

Resource related risks include consideration of the thermal capacity of the reservoir, rates of temperature and pressure degradation, uncertainty as to thermal recharge, and potential error in assumptions used in resource simulation and the effect on the reservoir of seismic activity. These areas have been the subject of much discussion on a technical level, but they also have a substantial impact on contractual requirements. Either the resource producer must guarantee supply, except possibly for "force majeure" events, with an associated recognition of his risk assumption in energy price, or the utility purchaser must assume such risks. If the utility assumes such risks, it must be privy to all resource related data, and possess (or contract for) the capability to adequately evaluate such information.

Risks related to the operations of the resource developer vary in magnitude depending upon the experience and demonstrated ability of the developer, and can be subdivided into the two major areas of resource production and utilization, and reinjection. Under production and utilization fall such areas as well design and completion, separation of steam (if not done by the utility), control of corrosion and scaling in production lines, and quality control. Reinjection presents a major risk area, as well as a potential solution to water problems. If less than 100% reinjection is required, the utility may use the condensate as a source of cooling water without need of makeup water for reinjection or having to use external water for cooling and relinquish the condensate for reinjection. Regardless of the extent of reinjection required, much of the non-utility risk is related to such action.

Many liquid-dominated systems are highly saline and corrosive, and oxygen introduced into the system exacerbates corrosion problems. The ability of the producer to inject continuously and the life of production and injection facilities is crucial to the economic viability of a project and must be recognized in any contract. The utility must have adequate protection from the 'optimistic' supplier who subsequently finds that his projected capital requirements were inadequate. This protection should include frank discussions of a producer's plans, as well as a means of acquiring his assets and rights to produce in the event he is unable to continue and no acceptable solution can be reached.

Regulatory risk is one which grows increasingly important in today's climate of conflicting state and federal policies (if such policies do exist), overlapping or mutually exclusive jurisdictions, the integrity of confidentiality agreements between utility and supplier, air quality regulations and delays in securing permits for construction and operation. The air quality problems may vary between geothermal resource areas, and regulations requiring percentage reductions instead of quality limits could entirely change the economic viability of a specific project without contributing significantly to air quality. If a utility is to assume the 'resource risk', they must see such data which the producer wishes to keep confidential. These and other regulatory problems such as potential taxes must be accounted for in a supply contract, and delays due to failure to secure necessary permits and approvals must be considered as uncontrollable forces for contract purposes.

Public action includes both action from third parties to prevent development, such as environmental groups and local landowners, and action as a result of damage caused by operations. As with all generation projects, sources of water are bitterly contested as well as concern over emissions and noise. Additionally, the utility runs the risk of being included in suits over subsidence or claims that geothermal activity caused seismic events which caused damages, either real or imagined. A contract for geothermal energy should clearly spell out liability for various possible actions, delineating between producer related problems and those of the utility. This distinction is not always clear, and may have to be artificially determined by the parties or in some cases, assumed mutually.

The abovementioned four groups of risk are not considered exhaustive or mutually exclusive. Some areas of risk could fall into more than one category and the distribution within category and of liability between parties depend upon the division of responsibility between the parties.

One additional area of risk which has not yet been discussed could fall into the operator's area except that it is influenced, and may be caused, by the utility on certain occasions. This risk is caused by the relationship between availability of energy and payment to the producer and the fact that the relationship between utility and purchaser is almost unique in the energy industry. Most sources of energy are amenable to transportation, and power plants can accept fuel from more than one source. This is not the case in geothermal development and thus, the options of both parties are substantially reduced. This dependence upon the operations of another party is very evident when one addresses pricing provisions in a supply agreement. The producer is investing capital which can only be utilized to supply one customer and the utility is building a plant which will not operate if the producer cannot. This risk of non-supply (or consumption) must include consideration of installed capital as well as lost revenues, and either party may be causing risk realization to the other. In the short term, a contract must grapple with definition of whose problem is causing a less than capacity operation, and identification of this issue is not always simple. A short term inability to supply could be caused by a previous inability to receive (getting production on line again), or the reverse may be true. In the long term, technical problems may lead to limited production capability or even abandonment of facilities.

The solution to such problems may require very innovative and complex pricing provisions, and termination provisions which involve transfer of assets and possible assumption of operations of a type unfamiliar to a party. There is also a risk that long term problems could cause a substantial decrease in the value of capital assets.

GEOTHERMAL DEVELOPMENT RISKS

FROM

SAN DIEGO GAS & ELECTRIC COMPANY'S PERSPECTIVE

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Introduction Risk assessment, as it pertains to new technology developments or to the application of existing technology to a new emerging energy resource, as is the case for geothermal energy, is a critical function. Perceived risks can block the path of development causing delays in the implementation of a new, promising resource alternative.

The risks of geothermal power plant development which are presently recognized, and which could have a significant impact on the cost of electricity from this resource option, are discussed in this paper. The term "risks", as used here, is in the conventional sense of denoting the probability of occurrence and the potential consequences of such occurrence. The latter encompasses a spectrum ranging from simple schedule delays, and their related project additive costs, to full termination of activities. The probabilities of occurrence are almost entirely subjective at present because of the lack of a commercial geothermal power plant data base.

No attempt has been made in this paper to evaluate the public risk/benefit of developing this resource option or to make a risk/benefit comparison with other electrical generating resource alternatives. This is clearly not within the scope of this presentation. However, such an evaluation should be carried out, and kept current, under the auspices of EPRI or some other appropriate agency in order to determine possible future roadblocks to geothermal energy development.

Categories of Risk To assess the risks to a utility of commercial geothermal power plant development, three broad interrelated categories of considerations must be reviewed and their potential economic consequences estimated. These three categories of risk include:

Technical
Environmental
Regulatory

All three of these categories of risk contribute to potential economic consequences and directly translate into economic risks impacting the busbar cost of power. Decisions emanating from any one of these three categories may impact the other two, and these in turn may impact the plant economics, either directly or indirectly. For example, a requirement imposed by a regulatory agency may dictate certain technical changes to a plant which could impact environmental considerations. Not only would the technical changes have a direct economic consequence but also an indirect consequence as a result of addressing the resulting environmental considerations.

Risks Identification Most of the significant geothermal development risks relative to the technical, environmental and regulatory categories have been addressed in detail in other presentations during this conference session. Therefore, I will merely present a cursory examination of these risks in summary form and will address, in somewhat greater detail, the significance of these risks as they relate to their potential economic consequences and impact on the pace of geothermal development. With this perspective, we will be able to focus on those actions which are needed by the geothermal industry to meet the objective of speeding up the progress of power plant development.

Technical Considerations

1. Resource Dependability - The fact that a constructed geothermal plant is tied to a specific single location for its "fuel" supply places it at a disadvantage in comparison to other resource alternatives. Having a contingency back-up supply in the event of a future fuel supply problem, as is the case for most conventional resource options, adds an element of flexibility which reduces risk. Unfortunately, once a geothermal plant is constructed, it is permanently committed to the fuel supply located at that site. This emphasizes the importance of having a higher degree of confidence in the fuel source dependability for geothermal plants as contrasted to conventional plants.

Although some of the resource developers have extensive test and operational experience with certain of the geothermal reservoirs, the fact remains that commercial-scale withdrawal and injection of brines over time periods measured in decades have not been demonstrated for any liquid-dominated hydrothermal resources. Depletion (temperature, pressure or flow rate) and chemistry-related problems (scaling and corrosion) are the primary recognized possible consequences.

From the technical point of view, these risks give a utility reason to proceed cautiously in its pursuit of geothermal energy development. For example, at the Niland Geothermal Loop Experimental Facility, injection well plugging (and plant scaling) problems have seriously delayed SDG&E's testing program at that site. A promising solution to the injection problem has been identified by small-scale tests--the use of a clarifier in concert with filtration--and a demonstration of this concept on a large-scale now remains to be completed in order to confirm successful resolution of this problem area. For the low salinity Heber reservoir, early testing by SDG&E and EPRI have shown that it is reasonable to expect there will not be a well plugging problem at this reservoir with the utilization of the binary cycle and single-phase brine flow. Therefore, plugging is not expected to be a significant risk for binary plant operation at low salinity reservoirs. However, there is no evidence to date that well plugging will not be a problem for flash cycle plants at low salinity reservoirs. If this occurs, it could seriously delay the implementation of presently planned flash cycle plants. It might well be necessary to clean up these brines with a clarifier and sand filter similar to that which will be tested at the Niland GLEF facility.

Regarding depletion, the initial demonstration plants should yield some near-term confidence in the reservoir's ability to sustain operations over the life of the power plant; however, there are certainly no long-term guarantees that the reservoir will continue to produce for 30 or 35 years instead of a possible 20 or even only 10 years. This presents an economic risk which will be discussed later.

2. Power Plant - From a technical point of view, the power conversion portion of the geothermal plant appears to have low risk for the flash cycle and moderate risk for the binary cycle due to its developmental status at the present time. The energy conversion equipment is unlikely to totally preclude successful plant operation, although its performance unquestionably affects very strongly the plant economics, brine usage and cooling water requirements. The potential inability of the conversion system to attain design performance criteria does constitute a risk, however.

This conclusion appears to be valid depending upon the energy conversion system employed since the flash cycle has the advantage at this time. The flash cycle has been subjected to relatively extensive demonstration at several non U.S. liquid-dominated geothermal sites in the world.

Both of the energy conversion cycles are relatively simple, operate in low temperature and pressure regimes by contemporary power plant standards, and employ no exotic or unusual components, materials or systems.

The Heber plant will provide a successful demonstration of the binary cycle. The risk associated with the binary cycle is estimated to be moderate since this cycle has never been operated on a commercial scale. The major uncertainties of this cycle concern the turbine design and performance and plant operational safety. The major unknown capability in the process area is the thermodynamic properties of the binary fluid, particularly the enthalpy difference available to the turbine as the supercritical binary fluid is converted to superheated vapor.

Poor performance (e.g., low cycle efficiency and plant availability) may well occur in the early plants, but performance is expected to improve with experience based upon the past history of technology development. For example, component and system reliability is clearly a key technical consideration because of the strong economic dependence on plant capacity factor. There does not appear to be a question of components completely failing to operate, but rather a question of the reliability of that operation. This uncertainty will be resolved by the initial demonstration plants.

Binary cycles employing a hydrocarbon working fluid introduce a risk unique to the power generation field but common in the chemical and gas processing industry. Because of their experience, the technology for the safe design, construction and operation of the working fluid loop and associated systems is considered available, even though explicit demonstration of commercial-scale power plant equipment will have to await the Heber plant's operation. The important consideration from SDG&E's point of view is to ensure that pertinent standard refinery practices are adhered to and that operating personnel are appropriately trained.

In summary, while developmental difficulties may initially be expected, none are now judged likely to be of the type to preclude plant technical feasibility. However, the initial demonstration plants are required in order to confirm these expectations. For these reasons, the plant technology aspects are considered to be in the low to moderate risk category as discussed in this section.

Environmental Considerations The primary risks in this category are induced seismicity or subsidence as a consequence of brine withdrawal or injection, and water availability for power plant cooling. Possible air emissions resulting from exhausting noncondensible gases from flash plants is another consideration. Due to the lack of actual commercial-scale operating experience, a categorical low risk assessment cannot legitimately be assigned to these risks at this time.

Considering first the possiblity of induced seismicity or subsidence, theoretical understanding of seismic mechanisms and experimental evidence acquired to date support the conclusion that the probability of severe adverse effects will be low. Although the probability of serious seismic or subsidence effects may be low, their consequences of occurring could be large, requiring serious consideration of this risk. The satisfactory confirmation of these early assessments will necessarily have to await commercial-scale plant operation through the initial demonstration plants.

Of all the environmental considerations, cooling water availability and use probably constitutes the largest future risk to expanded geothermal activity. Local regulations in the Imperial Valley preclude the use of fresh cooling water in this otherwise water-scarce area for commercial power plant cooling purposes. This translates to the near-term use of irrigation drain water and possibly the eventual use of more expensive wet/dry cooling towers, and plant designs based on average rather than most-adverse heat rejection temperature.

Inadequate cooling water availability for geothermal power plants clearly constitutes a sizable risk to the future large-scale development of geothermal resources in the Imperial Valley. Proposed solutions to this problem must be clearly and openly arrived at by working in conjunction with local agencies and organizations.

Regulatory Considerations It is apparent that there is substantial political initiative supporting geothermal development, particularly in California, at this time. This political support needs to be converted into tangible incentives which will attract the industry and motivate it to accelerate geothermal development.

Since the regulatory process is tied so intimately to public and political pressure, the major regulatory risk is that currently favorable attitudes toward geothermal energy could change dramatically in a relatively short time. At one time, the nuclear option received the same type of public adoration that solar and geothermal are receiving today. Once geothermal plant operating experience is obtained, costs and benefits of geothermal power can be firmly established. Until that time, utilities will proceed cautiously in making geothermal plant commitments. Regulators and industry members critically need data from the initial demonstration plants in order to make objective decisions regarding geothermal power production.

As I will point out in my discussion of potential economic consequences, the regulatory risk is a critical risk area that needs to be recognized and dealt with now.

Economic Consequences The technical, environmental and regulatory considerations all lead eventually to potential economic consequences. Due to the present lack of a definitive geothermal power plant operating data base, it is difficult to judge the cost of geothermal power. Opinions regarding the cost of power vary widely, depending upon the assumptions made relative to the risks discussed here today and each individual's own motivations. The initial demonstration plants are needed, and needed soon, to resolve these differences and to remove the current uncertainty regarding cost which continues to impede development.

First, based upon SDG&E's own experience with geothermal to date, it appears that geothermal power will be fixed-cost intensive. This conclusion results from the fact that each component of busbar cost will contain a significant proportion of fixed costs. The capital component is obviously all fixed; the developers are requiring that a major portion of the fuel cost component be fixed; and initial estimates show that 85% of the O&M cost component will also be fixed. In all, it appears that as much as 85% of the total busbar cost could be nonvariable for the initial commercial geothermal power plants. This makes the busbar cost of geothermal power highly sensitive to plant capacity factor. Thus, those risks which could impact plant and reservoir reliability are of major importance.

Second, based on SDG&E's discussions with the developers and our own experience with geothermal power plant design, it appears that the components of the total levelized busbar cost over the plant's operating life will be divided roughly into 25% for plant capital cost, 65% for the "fuel" (resource) cost and 10% for O&M cost for a 75% plant capacity factor. Thus, geothermal power costs are most sensitive to fuel charges and least sensitive to O&M costs, with capital costs intermediate. This, in concert with the high fixed-cost ratio, makes geothermal busbar costs moderately sensitive to plant efficiency. Therefore, those risks which could impact plant efficiency, such as premature resource temperature degradation and turbine performance, are also of major importance. It is also interesting to note that because of the relatively low proportion of total busbar cost attributable to capital cost, the total busbar cost is not strongly affected by the plant lifetime. Whether geothermal plants will have a 20-year life or a 30-year life will not substantially affect the levelized busbar cost of power; although plant operating life has a significant influence on investment cost recovery by a utility and, thus, investment risk. This relates to the earlier-described regulatory risk which reflects the concern that regulators may later change their attitudes about geothermal and not allow a utility to recoup its investment if the reservoir depletes prematurely. Premature depletion is a greater risk to the utility investing in a plant than it is to the resource developer because the plant capital cost is significantly greater than the cost of reservoir development to support the plant.

Another significant potential economic consequence of the regulatory risk results from the fact that individual geothermal plants will be small in size (50-100 MWe each) requiring a significant number of plants to amount to substantial power generation capacity. Transmission lines will not be sized to handle only 50 or 100 MWe but rather 200-500 MWe to be economical. If regulators change their attitudes toward geothermal after the initial plants are brought on line, but before the lines are allowed to deliver at full or near-full capacity, the utility would have an uneconomic investment in transmission lines to deal with.

Risk Reduction Three broad categories which influence the level of risk/benefit are:

* Sharing of potential liabilities among project participants and contractors through contracts.

* Research, development and demonstration activities to advance the state-of-the-art and reduce or mitigate constraints to development.

* Government incentives to induce development.

Given an acceptable sharing of risks among all involved participants, geothermal development will proceed expeditiously. However, if risks are concentrated upon any one entity excessively, without compensating rewards for accepting excessive risks, the progress of development will proceed very slowly. Currently, the utility industry apparently perceives geothermal risks to be too large to justify proceeding rapidly with large-scale commercial development. Evidence of this is the present lack of significant utility commitments due to prevailing uncertainties and a deficiency in incentives. The following actions are recommended to ameliorate many of these risks and to provide the incentives needed to accelerate geothermal development.

1. Through the cost-sharing arrangements provided for in DOE's currently-approved geothermal demonstration program, the first commercial-scale demonstration plant should proceed forthwith in order to achieve initial plant operation in the early 1980's. The binary cycle should be developed on a commercial scale due to its potential efficiency and environmental advantages as well as its application to the lower temperature resources. This first demonstration plant will establish needed baseline data to reduce uncertainties and improve confidence.

2. EPRI should undertake a generic risk/benefit assessment to identify possible future roadblocks to large-scale commercial development.

3. Tax incentives for developers and utilities and tax reductions which flow through to impact the cost of power are needed to make hot water utilization economically attractive.

4. Public Utility Commissions should recognize the uncertainty of reservoir longevity and approve an accelerated write-off of plant investment, say over ten years, at least for first generation plants. An alternative, or possible supplement in this area, is for industry or government to provide some form of insurance against premature reservoir depletion.

5. A higher rate of return or some other economic inducement, such as including CWIP in rate base prior to plant startup, should be provided to utilities for investing in riskier nonconvenional energy development opportunities.

6. Additional R&D is required for technology improvements to support second generation plants in the areas of performance efficiency and reliability. Efficiency improvements are critical since performance efficiency has a strong influence on the busbar cost of power and of cooling water requirements of geothermal plants.

Summary All planned power generation projects, including conventional plant types, have attendant risks. The results of risk (and benefit) assessment are inputs into the decision-making process in determining which available resource options to pursue. Accordingly, the risks and incentives for pursuing geothermal development are not viewed in isolation but rather are measured against the risks and incentives associated with conventional resource alternatives. From a technical standpoint, geothermal power is at a disadvantage because at present there are no commercial-scale geothermal power plants operating on liquid-dominated resources in the United States. This "undemonstrated" status of geothermal power creates significant uncertainties and, therefore, there are significant perceived risks. Accordingly, uncertainties should be reduced with demonstration plant operating experience and incentives for development should be established.

DEVELOPMENT RISK

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PNM has been actively interested in the prospects for development of geothermal energy in New Mexico since 1969. Our interest is due, in part, to potential geothermal plant advantages of smaller baseload units in the event of unit outages, the relatively short lead times associated with the small unit size, a desire for added fuel diversity, a recognition of limited fossil fuel reserves and a potential supplement to future coal or nuclear baseload units.

Utilities are currently in a dilemma as to establishing a policy with developers which will both promote geothermal resource assessment and yet reduce, as much as possible, front end financial commitment to an unproven hydrothermal reservoir. Early communication between the utility and developer, however, is necessary for long range planning purposes.

It is well known that a developer with a yet unproven field does not have all the information a utility requires prior to any financial commitment, such as reservoir life and quality, steam price and escalation, anticipated operational performance, etc. The developer can provide the utility, in the early stages of field development, with his long-term plans and information such as the location of the development and anticipated development plans. In turn, the developer can expect information from the utility, such as utility growth rate, preferred plant design, existing and planned transmission routes, etc. As field assessment is occurring and a better understanding of drilling costs, reservoir extension, and so forth is evolving, contractual terms and degree of utility involvement can be better quantified.

Generally, developers prefer to have (in order of preference) front end utility capital commitment prior to field development, contractual commitment as early as possible with as little field verification as possible, a general letter of intent, and information on when and at what competitive price the utility would like to purchase the steam or power.

Alternately, the utility would like to have (in order of preference) full field verification as soon as possible with as little contractual commitment as required, field development plan, information on the developer's anticipated commercial availability of the geothermal field with projected steam or electrical power pricing, escalation provision, and general contractual provisions.

By law, a utility is required to (1) meet load requirements, and (2) do this as economically as possible. Therefore, reservoir assurance is viewed by the utility not only as an economic concern, but also more importantly, as an availability concern.

It does appear that two of the key criteria on contractual pricing are an assessment by the utility of what it can economically pay (specific transmission cost should be included) and an assessment by the developer as to the expected price of their product and the anticipated escalation of that price.

THE RISK OF GEOTHERMAL DEVELOPMENT

THE PUBLIC VIEW

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Introduction New construction of fossil, hydro-electric, and nuclear power have all met varying degrees of public opposition due to the environmental consequences. The general public is not yet very aware of geothermal energy, so one might expect geothermal development to be noncontroversial. The case study presented in this paper will review a geothermal leasing which generated public concern bordering on alarm. This paper will review the worries actually expressed by the citizens, the causes of the worries, and the methods which would reduce such fears in the future.

Public Concern In the spring of 1975, the U.S. Forest Service (USFS) announced its intention to lease up to 490,000 acres in the Jemez mountains near Los Alamos, New Mexico, for geothermal exploration. The USFS invited input from local governments, and the degree of public concern necessitated hearings by the Los Alamos County Council. The unanticipated concern was due to three causes:

1. the leasing was to occur in an area of natural beauty;

2. the citizens were politically active and many of them had deliberately chosen to live in an unspoiled place; and

3. not much was commonly known about the risks of geothermal development, so the citizens wanted information. At that time, the information was both difficult to get and somewhat disquieting.

Public questioning centered on the following consequences of geothermal explorations and operation:

* Air pollution - Most discussion centered on the common geothermal releases of hydrogen sulfide, ammonia, and radon. However, one questioner asked if the even more toxic tellurium, selenium, and arsenic compounds of hydrogen would not also be present. None of the experts at the hearings had an answer.

* Water pollution - The citizens feared surface water contamination from effluent brines, pipeline failures, siltation, drilling muds, and thermal discharges. There was also concern with saline or other chemical pollution of subsurface aquifers, either from infiltration or through eventual rupture of well plugs and casings.

* Water consumption - If an economically viable geothermal field were found, the predicted requirements for cooling water far exceeded the known supply.

* Noise - Many people regarded the predicted noise, both of drilling and of routine production, as objectionable.

* Soil disturbance - People were most concerned with the widespread roads and surface scarring which would occur during exploration, but they also recognized the disruption which would be required if many power plants were to be located over an extensive field.

* Surface subsidence - This was regarded as a more remote or more acceptable risk, probably because the land is sparsely inhabited.

* Wildlife disruption - This was feared if human activity were allowed to cover a large geographical area, or if roads were left open after unsuccessful exploration.

* Public access - The land in question is a natural recreational area, and citizens feared that they would no longer be allowed traditional use of the area.

* Boom town development - None of the nearby communities had the combination of available land, staff, and budget required for orderly rapid growth. It is generally recognized that the tax base from new residential development does not expand as much as the required new services. The commercial tax base must expand in order to support the residential growth. However, the geothermal growth would occur on federal land beyond the jurisdiction of the communities.

Experts who spoke at the hearings and at subsequent public programs explained the known technical solutions to some of the air, water, and noise problems. However, the regulatory situation was both confusing and inadequate, so the citizens were left with little assurance that the technical solutions would in fact be applied. Consequently, the citizens demanded that the USFS prepare a full Environmental Impact Statement specifically for this leasing. The USFS did prepare a good EIS which recognized the major problems, and which promised some protection for surface waters and soil through conditions to be placed on the leases. However, the most disquieting problem was the lack of enforceable environmental protection, discussed below, and this problem still remains. To receive broad citizen acceptance, a large project must have enforceable protection, credible spokespersons and evidence that someone is in charge.

Enforceable protection The problem was not one of pollution control technology, but was the citizens' justified fears that the technical controls might not be used. By "technical control" here, we mean physical measures which vary from regrading disturbed land to scrubbing waste gases. Environmental protection must be specified in quantitative terms--in numbers--with means for legal enforcement and penalties for violation. Contractual agreements in leases or licenses do not guarantee protection because no law is broken if the conditions of the lease or license are violated. Enforcement of a lease or license depends solely upon the desire and capability of the relevant agency to prevent breach of its own agreement. For example, the uranium mining activity in New Mexico has polluted both ground and surface waters in violation of license conditions, yet enforcement did not occur.[1] As a second example, the contract between the U.S. Department of Interior and the Arizona Public Service Company (which operates the Four Corners coal-fired plant) called for use of "equipment offering the most effective commercially proven electrostatic concept available under the technology known at the time of design." Yet because this term of the contract was not enforced, environmental workers spent nine years of effort in obtaining equivalent protection through the adoption of state regulations.

In New Mexico, the Oil Conservation Commission (OCC) has jurisdiction over geothermal activities. Yet the OCC has no regulations controlling air pollutants except one catch-all phrase: "All geothermal operations ... shall be conducted in a manner that will afford maximum reasonable protection to human health and life and to the environment." The rule on noise pollution is that "... adequate noise equipment shall be installed ..." on any well within 1500 feet of a house, church, or school. Requirements for water protection are similarly nonquantitative. A person experienced in pollution control recognizes that these regulations are not enforceable. There are no rules (as there are in California) governing disposition of wastes from reserve pits. In short, the citizens learned that the regulations of the State of New Mexico provide only a minimal level of environmental protection from the problems of geothermal development.

Federal regulations did not comfort the citizens, either. The Geological Survey (USGS) represents federal authority over the strictly geothermal parts of operations on forest land, while the USFS has authority over the surface use of the land. The boundaries between the two jurisdictions are not clear. I have not checked to see of the USGS rules have changed since 1975, but at that time the USGS allowed venting of all gases so long as air pollution standards were not violated. Many people do not recognize the lack of meaning in this kind of statement. An ambient standard does not have the force of law. It establishes a limit above which a certain kind of pollution is officially regarded to be excessive, but it does not establish what is to be done, or who is at fault, if the limit is exceeded. Furthermore, an ambient standard is often inappropriate. For example, the federal secondary standard for particulate in the atmosphere is 65 micrograms per cubic meter, which corresponds to a visibility of about 17 miles--not the 100-plus mile visibility which is natural to this region. Permitting pollution to the limit of the standards is often like saying the federal highway 55-mph speed guideline should be regarded as the speed limit in all neighborhoods. By implication, traffic moving faster than this should somehow be slowed, while citation of the individual motorist would not be mentioned in the law.

Thus, the USGS air pollution rule was but one more reference to ambient standards. Other USGS rules, such as providing no limit on noise within a large lease, were weak. No enforcement measures were provided by the USGS rules.

Credibility Fortunately, in the Los Alamos hearings there was no credibility problem. Environmentalists, the USFS, the OCC engineer, and an engineer from Union Oil all spoke without disagreement on the factual situation. This gave the public confidence in the information. However, geothermal items were frequently appearing in the state-wide newspapers at that time. There were some scare-type articles and there were some nonsense articles which erroneously stated that the regulations assured fine environmental protection. In addition, industry spokesmen led a newspaper to report that there had been no environmental effects at The Geysers! Such alterations of the truth would have been harmful had not valid information been given at the Los Alamos hearings and programs. In my opinion, falsification or concealment of the facts by either side ultimately causes confusion and delays which increase cost to the industry. The uncertainty, delays, and costs of the nuclear regulatory process form an example of this.

Someone in charge It was not clear to the citizens, or even to the agency spokesmen, just who (if anyone) would take action if and when environmental problems arose in the Jemez geothermal leasing. Since enforcement procedures were not specified in most instances, it was even harder to predict just what action might be taken. It looked as though a legitimate citizen complaint would be passed from agency to agency to wastebasket. The experienced citizens had seen that kind of inaction before, and did not want it again.

Summary The overlapping jurisdiction, the absence of means of enforcement, and the lack of quantitative regulations left the public unsatisfied. The result was the demand for a full Impact Statement. This caused the leasing to be delayed by about 18 months. While this particular leasing has now been accomplished, the regulatory deficiencies remain and will cause more costly problems if commercial development takes place.

The majority of the people will accept a technology for which the hazards are clearly announced, for which the social changes are orderly, and for which the use of the best available pollution control technology is defined and enforced. Historically, these actions were not taken for either coal or nuclear development, and the result has been political and legal fighting. We have an opportunity to do better in developing geothermal power.

To those governmental and industrial people who are working on geothermal energy, I have a plea. First, announce the problems to the public clearly and completely. To help you do this, there is available an excellent little book [2] which outlines the technology and the problems in layman's terms. Second, you should take initiative in drafting good model regulations which can be adopted and enforced by a single agency of state government. This will reassure the citizens in that they will not be forced to seek redress after pollution becomes unacceptable. It will also reassure industry, in that the rules will be established before a big investment is made, rather than threatening a change of the rules after capital is committed. I am confident that the public will accept the risks of geothermal development in return for the benefits if we do the above. The majority of the public does not expect perfection; they simply want a guaranteed best effort to minimize the environmental effects.

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THE GEYSERS ENVIRONMENTAL CONCERNS OR RISKS

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PGandE has been a pioneer in the area of geothermal development, and since it is a "new" technology, many of the environmental concerns or risks have engaged PGandE and the steam suppliers in a significant information gathering over the last few years.

Many environmental concerns are a direct result of the constituents of geothermal fluids. These geothermal fluids contain elements in both gaseous and solid form. The noncondensible gases and solids may be carried into the power generating units with the geothermal steam. Since these constituents can vary widely in different geothermal resource areas, extreme care must be taken to avoid making all environmental concerns universal to all geothermal development. My main comments focus upon the vapor dominated geothermal resource existing at The Geysers, and upon the concerns associated with the power plant.

Analysis of Geothermal Steam and Releases to the Environment After flowing through the turbines, the steam is condensed with cooling towers utilized as heat sinks. The delivered steam contains from 0.2 to 1 percent by weight of noncondensible gases. The primary constituents are carbon dioxide, ammonia, methane, hydrogen sulfide, nitrogen, hydrogen, and radon. The majority (0.8 percent) is carbon dioxide; however, a small amount is hydrogen sulfide (0.05 percent).

Each constituent found in the geothermal fluid undergoes physical-chemical processing as it passes through the power cycle and the design of the power cycle can radically alter its release points. The constituents that are presently of major concern are hydrogen sulfide (H_2S) and boron; H_2S because of its odor and boron because of its possible effects on vegetation close to the cooling tower.

Hydrogen Sulfide Emissions Abatement PGandE began investigating methods to control the H_2S emissions from The Geysers Power Plant in 1971. These investigations have included literature searches, parametric evaluation, bench-scale testing (both in PGandE's laboratory and at The Geysers), and unit-scale testing on actual operating units at The Geysers. The present status of this program was previously reported on in this Conference.

Air Quality Measurements of H_2S concentrations in ambient air at The Geysers and the surrounding areas have been made by PGandE on a monthly basis since July 1970.

An eight station, automatic, 24-hour, air sampling network operated by Stanford Research Institute and funded by PGandE, Union Oil Company, Aminoil USA, and Thermogenics, Inc., has been in operation since 1976. The data for 1976 indicate that the stations in Lake County exceeded the 30 ppb State Ambient Air Quality Standard for H_2S 0.4 percent of the hourly readings. This represents a total of 133 out of 35,200 readings at five sampling stations over 11 months. These data reflect air quality conditions with the total emissions from The Geysers of approximately 1700 pounds of H_2S per hour. It should be pointed out that the H_2S standard of 30 ppb is based upon odor and not health effects. Long time residents in the area state that H_2S odors existed prior to any geothermal development due to natural geothermal activity. It is unlikely, therefore, that total abatement of all H_2S from geothermal development would result in zero odors. The steep terrain makes air quality modeling difficult and the predictions of H_2S concentrations subject to large errors.

Cooling Tower Drift Effects of geothermal operations on the local vegetation were first noted in early summer of 1973 at Units 1-6.

General vegetation observations at The Geysers show that the effects are local to these operating geothermal units. Big leaf maple consistently exhibits the symptoms most clearly, and typically exhibit early senescence or leaf drop. It appears that the several species of native woody vegetation have varying degrees of boron tolerance. Mortality relating solely to drift impacts has not been noted.

It is our premise that the interactions of Units 1 through 6 cause a unique situation and that this will not appear at other units if proper cooling tower drift control is used.

Stream and Fish Studies Initially, the unevaporated condensate from the power cycle was released to the natural drainage channels. The condensate contains ammonia which affected the fish life. The problem of condensate disposal was resolved by reinjection into the underlying steam producing formations. A review of the power cycle used at The Geysers shows that these geothermal units do not require water from the surface streams or return water to the surface stream. That is, they are water independent since they use condensed steam to run the cooling cycle. In order to reduce the possibility of an accidental condensate spill reaching a stream, units presently under construction are being provided with containment berms.

Results of studies indicate good populations of fish, including steelhead trout, exist in most of the streams studied, and areas have been found where fish populations are low or nonexistent due to the action of natural geothermal activity in streambeds. A review of seven years of monthly water quality data reveals no correlation with geothermal activity.

A study is presently underway to determine if any siltation impact occurs during the construction phase of a Geysers unit. Rigorous application of known erosion control measures are the answer and new protection technologies are not required. A realistic evaluation of the impact of geothermal operations on stream and fish life would indicate that it is minimal if known environmental protection technologies are applied.

Vegetation Mapping and Wildlife Studies In late 1975, several regulatory agencies and geothermal developers entered into preliminary discussions regarding the systematic investigation of the effects of geothermal development on wildlife. The discussions centered around two basic points: (1) the amount of wildlife habitat lost due to the construction of well pads, roads, and power plants; and (2) the effects of geothermal development on adjacent unaltered wildlife habitat. From these first discussions and subsequent meetings evolved an efficient and highly successful cooperative study approach involving industry, regulatory agencies, and the academic community.

To determine the loss of wildlife habitat due to geothermal development, Big Sulphur, Kelsey, and Putah Creek drainages, which include about 90 square miles or 25 percent of the total Geysers Known Geothermal Resource Area (KGRA), were mapped. Data maps prepared included vegetation, hydrology, slope, and wildlife habitat.

On a per unit basis, the total disturbed land surface is 7-10 percent, with the major part being roads.

Following the completion of the mapping project, a cooperative wildlife study was initiated in April 1976, to answer questions regarding the effects of geothermal development on adjacent unaltered wildlife habitat. The wildlife study compared seasonal differences in wildlife population density within six habitat types located within the Big Sulphur Creek drainage for developed and undeveloped areas.

Species frequently associated with early successional plant communities appear to increase in density adjacent to development. However, species more dependent upon a climax or stable plant community decrease in density in developed areas. In general, the areas adjacent to geothermal development show a series of shifts in individual species abundance rather than a uniform increase or decrease in all wildlife species.

In analyzing the preliminary data, it appears that several habitat parameters other than the extent of geothermal development may be more significant in explaining the differences observed in population density. In general, the study results indicate that geothermal development is not a great disrupter of wildlife and that available mitigation techniques are applicable.

Noise Sources and Levels PGandE's noise measurements at The Geysers have produced a significant amount of information on the noise produced by a power plant during normal operation. In addition, levels of other geothermal noise sources have been measured.

A typical Geysers Power Plant operating at full load has three major sources of noise: cooling tower, steam jet gas ejector, and the turbine generator building. Measurements supplemented by acoustical calculations show that the cooling tower is the most significant noise source at distances greater than 200 feet from the plant perimeter. At a nominal distance of 500 feet from the plant boundary, total operational noise is about 60±5 dba with a wide-band frequency spectrum sounding similar to falling water.

The highest noise levels measured at The Geysers have originated from large flow-rate steam discharges to the atmosphere. This noise source is being abated through the installation of muffler systems.

At 500 feet from an operating plant, the remaining noise is essentially falling water from the cooling tower. It may not be possible to reduce this noise at the source.

Geology, Seismicity, and Subsidence The Geysers area is in a seismically active region. However, relatively few damaging earthquakes (Richter magnitude 4.0 or greater) have occurred in The Geysers region compared with other parts of California. Micro-earthquakes are, however, associated with geothermal fields in several areas of the world including The Geysers. It is PGandE's practice to perform extensive geotechnical investigations at specific selected locations considered for future power plant sites. Accepted engineering practice is then used to design the specific plant. We do not consider it a special problem requiring new technology.

Subsidence may occur under certain conditions in geothermal fields. Subsidence has occurred at liquid-dominated fields with unconsolidated reservoir rocks. At The Geysers, the reservoir is composed of hard locally metamorphosed sedimentary and igneous rocks, and a reduction in hydrostatic pressures is not expected to affect the hard reservoir rocks. The U.S. Geological Survey has set up a precise leveling network at The Geysers, and initial surveys indicate that some slight subsidence is occurring. However, it will be several years before resurveying will indicate if the subsidence is occurring because of steam withdrawal or tectonics. Resurveys of the subsidence monitoring network have not been done; therefore, the early indications of possible subsidence have not been verified as to their magnitude and cause, tectonic or induced. In over 15 years of productions at The Geysers, no problems have been associated with subsidence.

Conclusions The predominant concern at present is the emission of H_2S. PGandE has made significant contributions to H_2S abatement technology for geothermal application, and has developed the processes that are presently in use, and is actively exploring "upstream" processes for future application. Hydrogen sulfide abatement processes appear capable of controlling the release of H_2S. The degree of abatement required and to what standard will be a hotly debated issue in the next few years.

Geothermal development is a competing land use. It does not disturb 30-50 percent of the surface area as has been reported. However, it will disturb 7-10 percent of the surface area; the rest is available for alternative land use. Cattle grazing, hunting, fishing, predominant prior land uses, now coexist with geothermal development. Effects on wildlife appear to be minimal and available mitigation is applicable.

The power cycle design at The Geysers does not require water and no discharge is made to the surface streams. Long-term impact may be caused by erosion and erosion control measures are required.

Noise may become a limiting factor with regard to site locations since reduction of cooling tower noise may not be feasible or economical.

There are still some difficult-to-answer questions with regard to possible long-term effects, and a monitoring of The Geysers area will be required. However, some reasonable extrapolation to long-term effects may be available from areas where geothermal development has been ongoing for over 70 years.

However, except for H_2S abatement, it does not appear that new environmental protection technologies will be required as far as power plant operations are concerned. Environmental risks appear to be minimal and geothermal development may well be determined by societal decisions regarding alternate land use and the intrusion of industrial operations into what are low population areas.

"HOT WATER" PROJECTS AND THE ENVIRONMENT

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Other authors have discussed the environmental effects of dry steam reservoir development. This paper will discuss those effects which are unique to liquid-dominated reservoir ("hot water") development. The discussion will be limited to those effects expected from domestic development because it is expected that all geothermal fluids will be reinjected after use, rather than discharged to surface waters as is commonly the practice in other countries. This single operating requirement alters much of the impact of these geothermal projects.

The three major components of hot water developments are drilling (and its consequent testing), production (and corresponding injection requirements), and electricity generation (both flashed-steam and binary). The chief environmental points to consider when comparing hot-water development with dry steam development are listed below. Most other unlisted environmental subjects such as land use and socio-economic impacts are similar to those expected from dry steam projects.

Drilling
- ponds will muffle venting wells and scrub the steam

Production
- stacking is usually very short duration
- subsidence can be avoided or mitigated where necessary
- solid wastes are small in volume
- design measures are incorporated in the water handling system to minimize risks of spills

Flash
- existing emission abatement systems can achieve ambient air standards
- developing more cost effective emission abatement systems is a high priority
- no outside cooling water is needed if 100% reinjection is not required

Binary
- no air emissions occur when operating properly
- needs an outside source of cooling water because 100% injection

Flash and Binary
- power plant location may need land for cooling water pond, depending on injection requirements

From the above descriptions it is clear that hot water geothermal projects have distinctive environmental features which permit them to operate compatibly in most environmental settings. Since this is true, it is hoped that a large number of the hot water resources will soon be available for development.

RISKS OF GEOTHERMAL DEVELOPMENT

ENVIRONMENTAL RISK - REGULATOR'S VIEW

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DOE does not actually regulate geothermal activities, per se. I intend to speak basically from the environmental side of the Department of Energy. It is our (EV) job to obtain a balance within the Department of Energy, as technology development proceeds, between the purely technological concerns and the environmental concerns. But it is outside of the Energy Department and outside of the Federal Government that a great deal of the action involved in geothermal development is proceeding as we have seen at this Conference.

With respect to the prospects for geothermal energy, I would like to make the point that there has been a change taking place in the Energy Department's emphasis on relatively small-scale, alternate energy resources. The Department has acknowledged that the sun, wind, water and other alternative energy sources may play a significant role in the energy future on the United States.

The geothermal resources in the U.S. are, for the most part, not readily accessible and are difficult to develop. A majority of the most active geothermal development areas in the country are of the hydrothermal type--and of these, most are liquid rather than vapor dominated. Although the Geysers in California is the only proven dry steam field in the United States, there are quite a large number of potential hot-water geothermal development areas that have been identified. We are actively involved in environmental assessments to determine the environmental issues and impacts in these high priority areas. These assessments will form the basis for a determination as to whether a publicly reviewable environmental impact statement is required to meet the requirements of the National Environmental Policy Act (NEPA). The assessment or statement will provide the environmental input into decisions regarding geothermal developments.

For the vast potentially untapped geopressurized resource area under the Gulf Coast of Texas and Louisiana, we are presently evaluating existing data from very deep oil and gas wells that have been drilled into the hot aquifers.

For the hot dry rock systems--potentially the most extensive and widely distributed geothermal resource in the Nation--we are presently studying a specific promising area, the Valles Caldera, near Los Alamos.

We in DOE are aggressively pursuing the development of geothermal power; for example, our budget has been expanded from about $45 million in Fiscal Year 1977 to $120 million for FY 1979 for geothermal development.

Geothermal energy, however, although often hailed as a "major, nonpolluting, clean and natural energy source from the earth", does have its problems as well as its promises. Aside from its technology problems--which are not insignificant--there are a wide range of environmental, health, safety, economic, and institutional issues involved in geothermal development and commercialization.

Briefly, the environmental, health and safety issues include emission of non-condensable gases and salts, management of waste water, subsidence, and induced seismicity, noise, water supply, and potential for accidents, such as blowouts which could damage the soil and make it unreclaimable.

I will not dwell on the detailed discussion of these issues. You are all familiar with them, but I would like to make several points about these issues and share with you our philosophy and approach to coping with them.

President Carter, in submitting his National Energy Plan to Congress last year, said: "National policies for protecting the environment must be maintained. It is necessary to recognize the hazards and risks, and to reduce them to relatively low levels." The Department of Energy is committed to developing, demonstrating and commercializing our energy technologies not just within the bounds of environmental regulations, but to go above and beyond the letter of the regulations to minimize the impact to the environment. Our basic charter requires that we do the former; the President's policy and our own goals demand that we do the latter.

These sometimes contradictory objectives of increasing energy supply and protecting the environment are not easily met. Often energy supply technologies involve environmental degradation during many stages of the life cycle of the technology development process. Thus, before any energy technology program decision is made, the Department fully considers all the issues so that the information needed to determine the best energy options is available for decisionmakers.

In order to ensure that environmental concerns are considered early in the technology development and throughout the development, demonstration and commercialization cycle, we have instituted an environmental development plan, or EDP, for each energy technology under development. There are currently 32 completed EDP's. These plans identify the major environmental issues and constraints that must be addressed, and they are used to develop strategies for associated environmental research required being initiated early in the development cycle, they plan an increasingly important role in guiding the technology development as it progresses, so that the technology will be assured of compliance with the National Environmental Policy Act and the standards and regulations issued by the Environmental Protection Agency.

In order to support the development of these EDP's, we conduct several types of environmental studies. We conduct generic studies, particularly in the areas of ecology, biology, and human effects, which examine impacts that may be common to more than one technology. Secondly, we conduct studies, that address impacts unique to a specific technology, such as geothermal and a specific geothermal geographic area. In parallel with these two efforts, we also conduct studies to assess control technology needs and to identify environmental, health, and safety standards for technology development.

An example of a comprehensive site specific study is the Imperial Valley Environmental Project (IVEP). While this study developed data for the Imperial Valley, it also was a pilot program for an overall approach to identifying environmental assessment needs associated with energy development at any geothermal site. Time and money, of course, do not permit at all sites as extensive a monitoring program as was done at Imperial Valley, but much of this experience and knowledge gained at Imperial Valley is being used at other locations, like the Geysers-Calistoga resource area.

The IVEP was initiated over two years ago to develop baseline characterizations of the area, to identify potential impacts and to establish the environmental conditions before significant geothermal development was started. Imperial Valley is unique in the level of existing environmental data that has been obtained. These data were obtained through a unified program of surveys, field measurements, and analyses. More than 30 public and private agencies and universities have worked together to collect data on everything from air and water quality to the habits and habitats of the Valley's wildlife.

To evaluate water quality, we have established an extensive water-monitoring network, particularly in irrigation and drainage canals near existing geothermal wells. At more than 70 sampling points we gathered information on water salinity, pH, temperature, and ion concentrations. This was done to be able to quickly detect any brine contamination of surface water.

Air quality was studied at six stationary monitoring stations where measurements were taken on wind speed and direction, temperature, relative humidity, precipitation, and presence of such pollutants as hydrogen sulfide, sulfur dioxide, ozone, carbon dioxide, ammonia, and particulates.

A mobile lab was also used to make measurements at specific sources, and an airplane measured vertical pollution concentration profiles. This data was stored in a computer for use in modeling the transport and dispersion of airborne pollutants from postulated geothermal power plant sites anywhere in the valley.

To check seismicity and subsidence, we worked closely with other Government agencies to expand existing detection and monitoring networks. In cooperation with Imperial County and the State Department of Oil and Gas, we resurveyed the IV subsidence detection network, and we added six seismometer stations to the U.S. Geological Survey's regional seismic-monitoring network.

For ecosystem studies we used aerial surveys to assess crop damage and other impacts near the wells. Studies of effects of increased salinity were made on fish and foodchain organisms. Impact studies were also done on the bird population that winter in the area, and on the delicately balanced desert ecology.

Although health effects from the major pollutants from geothermal wells are well known and have been studied for other reasons, we worked with state and local health authorities to identify any additional research needed and to establish an exemplary health statistics reporting system for Imperial County. Socioeconomic baseline data documented existing conditions such as employment, population, land and water use, public services demands, and county fiscal structure so that possible changes might be predicted.

Finally, all of this information has been blended together so that we can make an informed, realistic assessment of the costs and benefits of developing this energy resource. Computer modeling plays an important role in this process, taking various development scenarios and providing analyses of predicted air quality, cooling water availability, and crop effects.

The most important and successful part of this integrated assessment effort, however, and of the entire IVEP, has been the exchange of information among the regulatory legislative, planning, and development groups that have the decision-making authority to implement this environmental program's recommendations.

We also have an Environmental Studies Program applicable to geothermal activities. The objectives of the program are to: (1) determine environmental implications of geothermal energy utilization and the means by which undesirable effects may be reduced to acceptable limits; (2) promote development of environmental criteria and standards, and recommend appropriate Government policy; (3) provide the technological capability to meet environmental standards at reasonable cost; (4) assure that environmental considerations are taken into account in the Geothermal Program decisionmaking process; (5) support and enhance resource development efforts of other agencies; (6) support promising regional or area resource development activities outside the Federal program.

The program is organized into three functional areas of effort which support the attainment of these objectives: (1) control technology and environmental research; (2) criteria and standards development; (3) environmental impact assessment and statement preparation. These areas are interactive.

Activities under the Control Technology and Environmental Research Subprogram element provide for identifying and understanding the environmental effects of geothermal energy production and utilization, including monitoring; and for developing and demonstrating control technology to minimize impacts and meet environmental standards at reasonable costs. Current and planned efforts include H_2S emission control, subsidence control, spent fluid disposal, seismicity, noise control and well blowout control.

I mentioned earlier, that DOE is not a regulatory agency. Accordingly, our efforts under the criteria and standards development program are directed toward developing the criteria and support data for the adoption of consensus standards applicable to geothermal energy development. By their very nature consensus standards are not regulations, and are not legally binding. Unlike DOE, EPA does have the authority to issue environmental regulations which are legally binding.

We have published a guidance document for our contractors and geothermal loan guaranty applicants. This document specifies the information which should be supplied to us in order that we can prepare acceptable environmental impact assessments and statements on DOE sponsored geothermal projects. We are hoping that our reporting guidelines are sufficiently thorough to encourage their adoption by state and local authorities who are charged with preparing statements of impact.

The geothermal program division has responsibility for the preparation of environmental impact assessments and impact statements, as required by DOE's regulations implementing the National Environmental Policy Act of 1969, for the overall geothermal program we well as individual projects. An environmental assessment is a written report based upon an evaluation process to assure that environmental values are considered as early as possible in the decision-making process and to determine whether the proposed activity is expected to have a significant impact on the environment and therefore requires the preparation of an environmental impact statement. While an assessment does not contain all elements of a statement and is not required by regulation to be distributed for Agency or public comment, it is subject to a formal internal review process and is made available to the public. We have prepared generic or programmatic impact assessments for the hydrothermal, geopressure and hot-dry rock subprograms which will probably be followed by impact statements at an appropriate time during resource development. Project specific impact statements will be prepared for pilot and demonstration plants as required. Other projects which could potentially impact the environment will be subjected to an impact assessment to determine if impact statements are necessary.

It has been a pleasure to speak to you today.

ENVIRONMENTAL ISSUES

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Introduction Two previous papers in these proceedings present my summary of geothermal development in California and some State actions to accelerate that development. These papers, "Power Plant Commitments in California" and "Geothermal Development: Risks and Incentives," emphasize measures intended to encourage commitments to build the first hot water geothermal power plants in California. This paper on environmental issues emphasizes matters that affect primarily the expansion of geothermal power production capacity that can occur after first-of-a-kind power plants have proven the technical/economic feasibility of a particular combination of resource type and power plant.

Imperial Valley Action Plan I will describe here the most recent and direct case of State action to facilitate the rapid expansion of geothermal development that could follow success with the first hot water power plants. The California Energy Commission has contracted with the County of Imperial to execute the primary part of an Imperial Valley Action Plan that is to resolve the few remaining critical environmental/regulatory issues facing large scale geothermal power production in that area. The U.S. Department of Energy is cofunding the contract. In order to resolve in advance the major remaining issues the project will perform a transmission line corridor study and will utilize existing data and analysis to present plans for acceptable use of water for power plant cooling and for about 500 MW of geothermal generating capacity at each of the four major resource areas in Imperial Valley. The effect will be conducted by the County in consultation with other agencies and interests and will lead to recommendations by the Board of Supervisors of Imperial County regarding transmission line corridors for geothermal power production.

Environmental Benefits of Geothermal Energy Before discussing environmental risks, the subject of this particular section of the conference, I want to stress that geothermal power production has some environmental advantages relative to alternative forms of power production for California. The most important of these benefits are: (1) avoidance of the radiation risks associated with nuclear power production; (2) no emissions of pollutants that aggravate problems of photochemical air pollutants in the critical urban air basins ("non-attainment" areas), and (3) no contribution to significant deterioration of air quality in clean air regions protected by Federal and State regulations ("attainment" areas.

Environmental Risks versus Regulatory Risks Because I find that "geothermal environmental issues" usually is a heading that includes both the actual, physical effect on the environment and the government procedures used to control such effects, I am here making a distinction between environmental risks and regulatory risks. What I include as environmental risks are the potentially adverse effects of actual physical changes in the environment that are caused by a geothermal development project. These are risks that can be handled by designing, constructing and operating the project in a way that reduces or eliminates the physical changes that cause the risks or by not permitting the project to be built. What I refer to as regulatory risks are a combination of two sets of things: (1) the real, imagined and conceivable risks that are cited as possible problems, with the "real" risks being the ones I have already labeled as the environmental, as opposed to regulatory, risks; and (2) the uncertainties and delays that constitute risks to the project's success in the regulatory process itself.

Other papers in this section by Carl Weinberg of Pacific Gas and Electric Company and by Joel Robinson of Union Oil Company have named many of the specific environmental risks and also many of the methods available to deal with these risks in ways that enable projects to be built and operated successfully. In the remainder of this paper I will mention issues that could be resolved in ways that would reduce regulatory risk and the steps now being taken by the California Energy Commission to reduce the regulatory risk to geothermal projects.

Phased Projects: Exploration versus Development Regulatory uncertainty and risk would be minimized if a firm decision to permit complete geothermal development (i.e. well, roads, pipelines and power plants) were made at the beginning of a project. However, experience with local, state and federal regulatory bodies in California has not led geothermal developers to expect this ideal resolution of their regulatory risks. Many developers have preferred a separation between permits for the exploratory phase of a project (i.e., all activity prior to proof of a resource that results in a utility's commitment to build a power plant) and the development phase (i.e., the drilling of additional wells to meet the full requirements of an operating power plant and the construction of the plant itself).

Separation of the exploratory drilling phase from the rest of an anticipated project offers the advantage of reduced detail and scope of the environmental assessment and other steps to obtain a permit to drill. It offers the disadvantage of an approval for only part of the intended project and the absence of regulatory consideration of the environmental consequences of the full project. During the past year the Commissioners and the staff of the California Energy Commission have considered these advantages and disadvantages on Commission regulatory policy for geothermal power plants and in formulating recommendations that could be made for improvements in the system of leasing federal lands for geothermal exploration and development. Results of these considerations to date are published in the Geothermal Regulatory Policy Report adopted by the Energy Commission in March 1978 and in Commission staff contributions to a report presented in June 1978 to a federal task force on streamlining geothermal leasing procedures. Highlights from these documents include:

* No Energy Commission regulatory jurisdiction over the drilling of geothermal wells;

* acceleration of Commission power plant siting procedures to a total of 12 months rather than the two 9-month processes allowed in the law;

* use of non-regulatory advanced planning provisions in the law for Commission influence on geothermal projects that could later become regular power plant applications before the Commission;

* commitment to find mechanisms to allow but not require developers to obtain Commission views on power plant acceptability in specific geothermal resource areas before developers commit substantial funds to exploration or development;

* recommendations by Commission staff that federal agencies adopt the State of California practice of granting prospecting permits to allow exploration and favored status in obtaining a lease without granting a permit for full development.

I personally believe that exploration can be successfully separated from development in the regulatory process if developers and regulators clearly understand and enforce the distinction between a permit to temporarily conduct an exploratory drilling operation and a permit to build a geothermal field and power plant. Proper functioning of this regulatory option is worth pursuing because of the potential benefits of both an improved basis for estimating the future role of geothermal power production and an acceleration of schedules for bringing geothermal power on line from some new resource areas (beyond The Geysers and Imperial Valley).

Advanced Planning and Early Environmental Assessment The possibility and desirability of separating permits for exploratory drilling from permits to develop a field and power plant are related to another issue that has been addressed by both the Energy Commission and other agencies of the State of California. This is the issue of complete or "full field" environmental assessment early in the process leading from exploration to electricity production. The Energy Commission's Geothermal Policy Report of March 1978 and the earlier report of the State Geothermal Task Force recognized the desirability of advanced planning for acceptable geothermal development. During the past 6 months various mechanisms have been considered for achieving advanced planning that both accelerate geothermal development and provide adequate means of making the development locally acceptable. Within California state government the Energy Commission, the Resources Agency, the Governor's Office of Planning and Research and in the Legislature have been involved in considering these mechanisms. No general method for advanced planning and early environmental assessment has yet been put into operation. Energy Commission projects in the Imperial Valley (described above) and in The Geysers area are directed at meeting some advanced planning needs for these two geothermal resource areas.

Lack of information that can be obtained only by actually drilling and testing a geothermal reservoir is often cited as a reason why early environmental assessment is not practical. I personally do not agree with this view. It seems to me that, if we bound the problem by considering only the potential impacts of what would be an economically feasible geothermal development project, then we do know enough about possible impacts to determine the basic acceptability of the possible development and to identify any environmental protection measures that could be so costly as to destroy the feasibility of the project.

Current Energy Commission Activities In closing, I want to mention two current Energy Commission activities that bear on the issues discussed in this paper. The Imperial Valley Action Plan has already been described. However, I want to add that in performing that project and in planning for acceptable large scale development, the Commission and the County of Imperial will be using the data and analysis obtained by the federally-sponsored Imperial Valley Environmental Project. This experience will be a test of the federal effort to provide needed data and analysis through environmental baseline studies. I expect that the experience in the Imperial Valley can be used to improve future environmental baseline projects intended to support geothermal energy development.

The single most important Energy Commission geothermal regulatory activity at present is probably the processing of the power plant application by PGandE for Unit 17 at The Geysers. This is the Commission's first application for a permit to construct a geothermal power plant. The schedule for processing the application is consistent with the 12-month total time period the Commission expects to use for all geothermal power plant applications that are filed after the steam resource has been proved by drilling and flow testing. PGandE and the Commission staff have met in public workshops to identify and resolve issues and to discuss data requirements related to the Unit 17 case. Successful handling of the case within the 12-month period would be a significant positive sign for geothermal power production in California.

RESERVOIR INSURANCE OF GEOTHERMAL RESOURCES

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The utilization of geothermal resources for power generation has a unique aspect in that the generation facility is tied to a single fuel at a single site (much like a dam being used for power generation). When we speak of reservoir insurance of geothermal resources we are referring to the assurance that geothermal resources utilized in generation of electric power will have a sufficient life so that the cost of a facility utilizing a particular geothermal reservoir can be amortized without loss, or, at most, with a minimal acceptable loss, to the utility.

It is reasonable to expect that such insurance, in acceptable form, must exist if utilities are to be expected to construct plants to utilize geothermal resources and to rely upon those resources to supply their system requirements allocated to such plants.

In considering this subject, however, we must exercise proper perspective. We must recognize what we have learned from continuing experience -- that even as to conventional energy sources for generation of electricity in substantial amounts, there is either no complete assurance of supply, that is, the equivalent of reservoir insurance, or if there is reasonable assurance of adequate supply, there is often great cost entailed in utilizing such supply. In other words, complete assurance of reservoir life of a geothermal resource may not be necessary or reasonable to require in order to warrant use of geothermal resources as a competitive energy source.

Magma Power Company, as a resource producer, believes that it has the burden of demonstrating to the utility by acceptable means that the resource can be relied upon sufficiently to warrant the plant investment. For example, upon the assumption that its facility scheduled for completion in August of this year at East Mesa in Imperial Valley, California demonstrates the economic feasibility of utilizing middle-range geothermal fluids for electric power generation, there is sufficient land area in the vicinity of the plant to demonstrate, by means of drilling the appropriate number of wells and testing them by generally accepted methods, that the geothermal reservoir in that area can at least sustain a plant of agreed capacity for sufficient life to enable amortization of the plant. There is, therefore, no need for further reservoir insurance in such situations.

If, as installation of additional generating capacity is contemplated in the area, the utility is reluctant to rely upon reservoir life to sustain such additional capacity, or if despite apparent assurance by generally accepted means that sufficient reservoir life exists the utility remains apprehensive, the resource producer may deem it appropriate to reassure the utility by agreeing to reduce the price with a formula which would provide that in the event a plant's operating capacity is curtailed in any month within an agreed number of years because of reservoir failure or inadequacy, the utility may deduct from the amount payable to the energy producer for that month an amount equivalent to all or part of fixed overhead charges (which include plant amortization) allocable to such reduced capacity, so that if the plant cannot operate as contemplated by the utility because of reservoir failure or inadequacy, the energy producer defrays all or a portion of the fixed charges for the plant which may be attributable to the amount of capacity not available to the uitlity because of reservoir failure, for such month of operations at reduced capacity from such cause. For example:

Assume a 50 MWe binary cycle or flashed steam plant cost of $35,000,000. Assume also that 80% load factor is satisfactory to the utility (i.e., 7,000 hours per year plant operation).

The total yearly production would be 350,000,000 KWh. On a monthly average basis the production would be 29,163,333 KWh.

If payment to the producer for geothermal energy is 20 mills per KWh, it would total $7,000,000 for the year, or $583,333 per average month.

If because of reservoir failure or inadequacy the plant operating capacity is reduced to 60% in any month, the kilowatt hour output for that month would be down 20% (i.e., from 80% to 60% load factor). The production for that month would be 23,330,666 KWh. At the 20 mill per KWh price, the energy producer would be entitled to be paid $466,613 for that month (using an average month for our example) instead of the $583,333 which would be payable at 80% load factor.

However, if the energy producer is charged for the fixed charges allocable to the lost capacity, if we take an arbitrary depreciated plant cost of 30 million dollars and a 17% fixed charge rate, the amount chargeable to the energy producer for the month of such reduced capacity would be 1/12 (one month) of 17% (fixed charge rate) of 20% (amount of capacity not available because of reservoir failure) of $30,000,000 (depreciated plant cost), or $85,000, which would be deducted from the $466,613 otherwise payable to the energy producer for geothermal energy supplied that month. The balance payable to the producer would be $381,613.

Obviously such an arrangement should apply only in the event of reservoir failure or inadequacy, but not to the usual day to day occurrences or risks or requirements of the business.

Since the greatest single cost of electric power generation is the fuel, or energy, it should not be difficult to tailor a formula which would enable the utility to recover all or part of fixed charges and operating costs at substantially reduced load factors in the event of reservoir failure. In other words, the resource producer is, in effect, the insurer or co-insurer of the resource.

It is apparent that variations of this approach are possible. It is also possible, and perhaps likely, that the public utility commission having jurisdiction, in order to accelerate geothermal plant construction, might permit more rapid plant amortization as a cost item in the rate base, regardless of how the utility treats the matter for tax or financial accounting, or the commission might permit the utility a slight surcharge on its system sales for a period of years to enable the utility to create its own reservoir insurance fund until there is greater and more general experience with the resource in various areas. This would appear to be appropriate government support, especially if the producer assumes part of the burden.

It should also be noted that until further experience is gained from the first hot water geothermal reserves utilized, in an emergency situation the regional power pools and spinning reserves should be able to take care of system needs in the event a geothermal plant is not able to operate at full rated capacity because of reservoir inadequacy.

The program which I have outlined is practical and realistic and conforms to the traditional concepts of private enterprise. It offers the possibility of accelerated development and utilization of geothermal resources because it meets in a very real way the legitimate concerns of the utilities.

RESERVOIR INSURANCE: ONE UTILITY MAN'S VIEWS

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The question of need for reservoir insurance is at this time a hypothetical one. While some day a demonstrable need may exist, this has yet to be established and may in fact never be established.

These observations are written in the context of electric generating utilities constituting the users of a developed geothermal resource. The probable shorter payback or break-even periods for other forms of resource users may tend to reduce or minimize concerns about reservoir failures in other industries.

For purposes of analysis, it is convenient to think of the development of a geothermal resource or field as involving three phases.

The first phase is that of discovery or exploration - the finding of the resource. This phase could be seen as ending with finding commercial quantities of a geothermal resource. The second phase would then begin and consists of "proving up" the resource in order to establish, to the satisfaction of potential users, that the resource is one on which reliance can be placed. At The Geysers, with 20 years of operating history, this proving up of a new area is largely a matter of production testing, at least where a long step-out is not involved. In a new field, such as at the Imperial Valley, this second phase will necessarily be protracted since not only must the resource be tested through operation but also the technology for using that resource must be demonstrated. Construction and operation of pilot plants will be a necessity. This type of developing of assurance in the technology and the reservoir is exactly the way development of The Geysers steam field progressed. Over a period of years PGandE first installed a revamped, salvaged 11 Mw turbine and generator, then a 13 Mw unit, followed by two 27 Mw units and finally a 55 mW unit, Unit No. 5. Confidence in this field, and the equipment, came only with time.

The third phase in the development can be seen as one wherein the users of the resource have developed their confidence and are committed to development and production. This is the present state of development at The Geysers, where PGandE, the California Department of Water Resources and the Northern California Power Agency have all contractually committed themselves to build geothermal electric generating plants and are including such plants in their resource planning.

When a utility determines to build a new resource, it is interested in two basic things, namely, that the resource can be counted on to meet the utility's loads, and that it will do so at a reasonable price. If the unit is not available when needed, power from an alternate source must be obtained (probably at a higher price) or customers go unserved. A utility plant is quite expensive and must be amortized over a long period of time in order that rates may be kept at reasonable levels. Electric generating plants and associated facilities are typically amortized over a 30 to 35 year period. The reduced amount of generation from a geothermal field which has depleted more rapidly than expected can be ill suited to meeting the needs of a utility's customers and, because of the reduced output to which fixed costs can be applied,such generation can prove very expensive per unit of output.

These factors that go into a utility's choice of new resources initially would seem to argue strongly for the need for or desirability of reservoir insurance. Yet the very process of developing a field, as discussed above, can be expected to reduce that need to a minimum. The development of the technology and the drawing upon the field in the testing of pilot plants should establish the confidence needed for a commitment to development. The utility must be satisfied that the resource is reliable if it is to be relied upon for meeting customer load. So also the utility must have confidence in the long-term produceability of the resource if a long-term investment is to be made with the exercise of reasonable prudence. Insurance for failure of the resource does not meet customer load - it merely reduces the financial sting of that failure.

One aspect of reservoir insurance should be considered. As two other panelists have commented, private insurance companies express no interest in writing reservoir insurance policies. Unless utilities endeavor to set up a common pool to guard themselves mutually against loss, an insurance program would have to be governmentally sponsored. This probably would prove to be a disadvantage. Utilities, whether investor owned or public owned, tend to be jealous of their independence and suspicious of governmental programs. All too often attractive programs are found to have large "hooks" in them. Additionally, the ability to budget or not budget, which is inherent in legislation, makes program continuation subject to legislative whim.

Are there alternatives to insurance as a means of removing possible concerns of reservoir failure? Two such alternatives come to mind: (1) Especially in the case of regulated investor owned utilities, the utility which has concerns about a reservoir failure could have these relieved if it receives assurance that it can amortize its investment without being penalized by its regulatory commission in the event of such failure. This would not appear to be unjust to the utility's customers, since they received the benefit of the use of the geothermal resource while the field was functioning. (2) The risk of reservoir loss would be placed contractually on the resource supplier, or apportioned between the supplier and the utility user.

In conclusion, it does not yet appear that reservoir insurance is needed for geothermal development at this time. Development has taken place, and continues, without such insurance. This is not to say that a need for insurance may never become apparent. Such a program may be required in the future if concerns about reservoir life prove to be a material hindrance in developing resources. For now, however, it is submitted that the concept of reservoir insurance is one best kept in the arsenal, rather than being presently employed in the field.

A BANKER'S LOOK AT THE GEOTHERMAL LOAN GUARANTY PROGRAM

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To date, commercial bank participation in the development of geothermal energy has been through the U. S. Department of Energy's Geothermal Loan Guaranty Program. The Bank of America worked closely with ERDA (now the DOE) in drafting both the original legislation and regulations necessary to implement the program in 1976 and make the first loan. Two years later, and with a considerable amount of experience with the program behind us, we continue to strongly support the Geothermal Loan Guaranty Program both for field development and power plant construction projects as we believe it provides an essential bridge between the large capital requirements of the geothermal industry and the normal lending criteria of commercial banks.

Most commercial banks have established lending criteria for energy development within two main categories: Balance sheet lending and project finance.

In order to extend a "balance sheet" loan, a bank will normally require that the borrower be an established on-going business, capably managed with a good track record. Some of the traditional financial tests have included a history of good earnings, a strong working capital position and a balanced debt to net worth ratio. Amortization of loans made on the balance sheet basis is from the overall cash flow of the corporation rather than from the dedication of earnings of a specific segment of the company's operations. If the loan needs support, it is generally obtained by taking a security interest in such assets as inventory, accounts receivable or in some cases the fixed assets.

Project loans, on the other hand, provide a form of financing in which the lender looks principally to the cash flow and earnings generated by the development of a particular resource which, when processed, furnishes the source of funds from which the loan will be repaid.

All considerations forming the analysis of this type of lending must positively demonstrate the economic viability of a project and will generally include consideration of at least the following:

1. An evaluation by an independent consultant that demonstrates producible proven reserves exist at a value sufficient to meet all financial obligations and at payout still have adequate reserves remaining.

2. Evidence that the general management and technical operators are capable of developing the project.

3. A guarantee that the project can and will be completed.

4. Equity contributions which demonstrate the unquestioned dedication to the venture by its sponsors.

5. Cash flow from the project must show an ability to pay all royalties, taxes, operating expenses plus sufficient funds to service the debt and generate a fair return on the investment.

6. A maximum tenor of five (5) to seven (7) years from the first draw under the loan.

7. A mortgage on the assets of the project.

8. A favorable market study and normally firm purchase contracts for the product.

9. Occasionally additional security will be required in the form of guarantees or pledges of completion, production or purchase output from financially reliable sources.

The banking industry has a long and successful history of making project type loans to the extractive industry. Oil, gas, coal and mining loans have been a significant portion of many banks' portfolios for years, but the primary factor that has allowed us to make the extractive type loan is the ability of recognized industry experts to analyze and evaluate the proven reserves of the property being developed.

The Geothermal Loan Guaranty Program was developed in order to encourage both the exploration and development of geothermal energy and the establishment of normal borrower-lender relationships. The Guaranty provides a backstop for both the borrower and lender in the event of large development cost overruns or inadequacy of the basic resource. Project financing together with the DOE Loan Guaranty Program fits this type of situation and allows the resource developer, banker and government to form an alliance to carry out a viable venture. It is important, though, that the DOE Guaranty <u>does not</u> make an otherwise <u>unbankable</u> project <u>bankable</u>. The project must still be viable and demonstrate a significant opportunity for success before it can be considered for the DOE Loan Guaranty Program. The Loan Guaranty provides security against the resource and commercial risks inherent in a new industry which in some instances cannot be funded and supported by the developer and the lender cannot prudently take the uncalculable risk of an unknown resource base.

Utilizing the parameters of project finance which we have already discussed, the Bank of America has committed in excess of $75 million for three (3) geothermal development projects in connection with the DOE's Loan Guaranty Program. Two of these loans are for field development projects in the Imperial Valley and one is for a proposed power plant project in Utah. Only two other lenders, the Bank of Montreal and Nevada National Bank have extended loans on a similar basis.

We believe that the backup of the Guaranty continues to be required for both development of the resource and for construction of a power plant. In our opinion, the industry is still technically young and the inability to evaluate the reservoir remains a significant obstacle for the industry to operate without either a large corporate "pocketbook" or a backup guaranty as now offered by DOE's program.

The GLGP Program is complex and time-consuming insofar as a bank and the customer are concerned. We are all learning, though, and we are confident that the rough edges and obstacles are being smoothed out and an operable program is about to emerge.

Commercial banks and prospective developers must thoroughly understand the DOE program, its policies and constraints, some of which are:

1. <u>Tenor of the Loan</u>
   Although the Guaranty can cover loans up to 30 years, most commercial banks will finance only short to medium term maturities. If a bank does not wish to take on loans with tenors beyond five (5) - seven (7) years, arrangements must be made to include a long-term lender such as an insurance company or pension fund to take the later maturities.

2. <u>Interest Rate and Costs</u>
   In order to qualify for a loan guaranty, the interest rate charged the borrower must take into consideration the U. S. Government Guaranty. Administrative costs on the other hand for both the bank and customer can be high, as a substantial amount of reporting is required on the part of the borrower and considerable follow-through is required of the bank.

3. <u>Lending Criteria</u>
   The bank must decide at which point in the project it will lend. The Loan Guaranty Program will support lease acquisition, geological and geophysical work, exploratory drilling and development. It must also decide what constitutes the borrower's equity: DOE project costs criteria or its own.

4. <u>Guaranty</u>
   The bank must also evaluate whether it will accept the current DOE Loan Guaranty's partial reserve funding. It is generally recognized that the DOE Guaranty carries the full faith and credit of the U. S. Government, but if DOE cannot make payment on a claim because of insufficient funding, the lender must be willing to wait for an appropriation by Congress to be made during which time interest on the obligation would accrue at a rate to be established by the Treasury.

These represent but a few of the key issues which must be examined and resolved by both the customer and bank in considering the geothermal program.

Looking to the long term, however, and the expiration of the DOE's Loan Guaranty Program now scheduled in 1984, serious thought must be given by the developer and the lender to the following:

1. The developers must build an increasing financial commitment to geothermal energy in order that a sufficient equity base is available to carry future projects without the Guaranty Program.

2. A method of evaluation for the future potential of the reservoir must be developed so that the lender and ultimate purchaser of steam can rely upon the resource deliverability, enabling them to advance funds and enter into a long-term contract without the backstop of a guaranty.

3. The industry in cooperation with the buyers of steam for electrical generation must develop contracts of the usual fossil-fuel take-or-pay type. This is a criteria which

must be met before totally unguaranteed financing can be made available for development of power plants.

In closing, we believe that a great deal has been accomplished to date. A foundation for cooperation and understanding has been established among the industry, the financial community and the Government. A greater challenge lies ahead, however, if we are to build and develop this natural resource into an important source of energy in order that it can contribute its full potential to this country's energy requirements.

THE NEED FOR A GEOTHERMAL RESERVOIR INSURANCE PROGRAM

A FEDERAL PERSPECTIVE*

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The geothermal industry has repeatedly expressed the view that if certain equalities or preferences were available, commercial development of geothermal energy could occur at an accelerated pace. As an example, in 1973 the infant industry agreed with Congress that commercial development of geothermal energy could be accelerated by a Federal loan guaranty program, which subsequently became law in September 1974. After the Energy Research and Development Administration came into existence in January 1975, rules and regulations for the Geothermal Loan Guaranty Program were published and the program became operational in June 1976. In the intervening two years, a total of 10 guaranty applications have been submitted of which three are approved, two more are undergoing active consideration, while the others are in limbo due to insufficient supporting information.

The National Energy Act contains two items also designed to accelerate the development of geothermal energy by the private sector. These are: a depletion allowance competitive with that provided to the petroleum industry; and a tax credit on geothermal investments. Congress has been told by the industry that upon enactment of these measures geothermal development will accelerate through a flow of investment capital brought about by the prospect of increased profit. Moreover, the State of California has announced that geothermal energy is a preferred energy resource and is reported to be setting up measures to achieve electric production from geothermal reservoirs of 20,000 megawatts by the year 2000.

With the level of interest and program stimulation that is illustrated above, one would imagine an industry that is straining at its braces and ready to charge. Unfortunately, this is not the case because of another barrier to commercialization. This barrier is described as the reluctance by utilities (both investor-owned and public agency) to construct power plants that depend on a specific geothermal reservoir as a fuel supply. The concern attributed to the utility industry is over the lack of assurance that the reservoir can continuously provide fuel over the power plant's anticipated operational life. Should the fuel supply fail, the plant would become inoperative and its capital costs could no longer be recovered through the rate base. In such instances investor-owned utilities would recover the remaining undepreciated cost of the plant only by charging it against profit - hardly a move that would enhance management's posture in the eyes of stockholders. Similarly, public agency utilities shudder at the prospect of explaining a geothermal "white elephant" to local voters.

A solution to this barrier has been advanced, namely, a program of geothermal reservoir insurance. Upon a reservoir's failure to provide fuel in economical amounts the insurance policy would pay the utility for any remaining value of a power plant dependent on that reservoir for fuel. Unfortunately, there is not any private insurance company available and willing to write such a policy. From investigations conducted by researchers at the University of Southern California, insurance companies claim that sound actuarial data is lacking, and therefore a reasonably sound premium schedule cannot be formulated.

There has been advanced the thought that the Federal Government could undertake this insurance program on an interim basis until private insurance is available. A Federal financial incentive or reservoir insurance program requires complicated, time-consuming legislative and administrative processes. Undertaking an effort involving an expenditure of time and resources can best be achieved by a clear demonstration from the geothermal industry of its probable use of such a program and of the anticipated results in the form of megawatts on-line. To be realistic, a Federal program would require enactment of necessary legislative authority and the resolution of a multitude of problems including the development of a reasonable premium schedule, rights of the government, obligations of the policy holder, and whether the reservoir developer could be held liable for reservoir failure. Technical questions are more difficult to answer - such as a standard as to what would constitute an event of reservoir failure and whether the Federal Government should be able to force the reservoir developer to resort to down-hole pumping or to drill additional wells in order to avoid failure.

These questions are formidable and the answers may not achieve desired results. The purpose of this paper is to suggest that if the utilities' perception of this barrier is real, there are alternative measures to a Federal reservoir insurance program that are worthy of consideration.

These measures are:

- o Enactment of State legislation that would require Public Utility Commissions or other regulatory agencies to treat, for tariff base purposes, the first power plants at a geothermal reservoir, as an R&D facility eligible for accelerated depreciation (e.g. 5 years). This measure would enable utilities to recover plant costs through the rate structure thereby minimizing concern over the reservoir's life. Experience with that plant and its supporting reservoir could be used by the utility industry to determine whether additional plants could similarly be supported.

- o Construction of "turn-key" power plants built by companies willing to assume financial risk in exchange for a guaranteed rate of return generated through the sale of electricity to a utility. This interim measure could provide a utility with data regarding reservoir performance without requiring the utility to risk construction capital.

- o Utilization of the existing Geothermal Loan Guaranty Program that would ensure loan payment to a lender for unpaid principal and accured interest on a power plant dependent on geothermal energy. This program permits a borrower to use project financing techniques whereby loan repayment comes only from the power plant's income and is not dependent on other corporate income. Under this program, a participating utility would be able to repay the debt through government assistance and would not be concerned with rate base restrictions regarding recovery of cost on unproductive plant.

These illustrative measures are suggested as worthwhile and, relatively speaking, readily available alternatives to a prospective program of Federal reservoir insurance. Industry's experience with these alternatives can be a determinant in considering legislation for other forms of Federal financial incentives which are proven to be necessary to stimulate geothermal utilization and development.

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* The opinions expressed in this paper are those of the author and should not be interpreted to represent a DOE position.

GEOTHERMAL RESERVOIR INSURANCE AS AN INCENTIVE FOR GEOTHERMAL DEVELOPMENT

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There is considerable interest today, both within the geothermal resources industries and in the government, of evaluating "Reservoir Insurance," probably with some government participation, as an effective incentive for encouraging development. This interest is in response to one of the major obstacles to geothermal development: the site-dependency of a plant that decides to rely on geothermal resources as a base. For any company so interested, site-dependency introduces a new risk, to be added onto all the other risks that must be considered in the near term: the possibility that rapid diminution of the field's utilizable heat content will undermine the profitability of the dependent plant before it has been amortized.

A reservoir insurance program, if insurers could be interested (see below), would presumably name, as beneficiaries, the plant operators (rather than the field development companies). The insured risk would be loss of reservoir potential -- more specifically, the lost ability to produce energy in an amount equal to the plant's rated capacity, prior to the full amortization of the plant's life. There would be several ways of defining this loss, i.e., in terms of inputs such as pressure, heat, etc., or in terms of net energy yield. Similarly, there would be some definitional problems in defining "loss of unamortized value of plant owing to reservoir incapacity," but, in principle, there is no reason why agreement could not be reached. It is not anticipated that loss would be absolute; no field will be dedicated to production without some fairly solid evidence of producibility, so that the real question is whether a field on which a 100MWe plant is situated will produce 100MWe over the life of the plant, or whether, starting in year 15 it will begin tapering off so as to average 50MWe over the next 15 years. As for the dollar amounts, on the assumption of plant costs of $500-$600 per kilowatt, and, hence, a 100MWe plant cost of $50-$60 million, if the plant life were 30 years, depreciated on a straight line basis, the halving of capacity over the second half of the plant's life would represent a loss of something on the order of $15 million. (Assuming some degree of co-insurance, the payment on the policy would be somewhat less than that.)

Thus far, the author's requests for expressions of interest among private sector insurers has proved unrewarding. Insurance companies contacted (including Lloyd's brokers) regard this proposal as a request for "financial guaranty insurance" (essentially, business loss), rather than casualty lost, even though the depletion of water below ground would seem to the author much like an overabundance of water above ground, which is underwritten against as flood insurance. There is a possibility that the program could be made more attractive with government involvement, much the way OPIC has providing insurance against expropriation for U.S. companies operating abroad. The government might participate either in the sharing of premium payments, or by standing behind any loss over and above a certain amount, e.g., limiting the private insurers' loss to a fixed ceiling (somewhat parallel to nuclear accident insurance).

How such a government plan would compare, in cost-effectiveness, with other incentive strategies, is a matter that cannot be discussed in the abstract, but only by reference to some more concrete proposal, which will have to be hammered out with insurance company - government cooperation.

BRINE CHEMISTRY AND COMBINED HEAT/MASS TRANSFER

EPRI Contract RP 653

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Introduction Mineral scale deposition is commonly observed in geothermal wells and power extraction equipment. In some cases, the scale deposits can seriously affect fluid production, energy extraction, and fluid disposal.

The formation of scale is not an inherent characteristic of the geothermal fluids, but is a chemical response to the energy extraction system and process specifications chosen by the engineer. Once the relationships between scale formation and fluid thermodynamic and hydrodynamic changes are understood, and made quantitative, the engineer has the opportunity to tailor a power plant system to a specific geothermal reservoir to minimize the scale deposition problems.

The objectives of this project are to:

* Determine the reasons why scale forms and assemble a data base on the chemical factors affecting scaling.

* Develop computer models to describe scaling in quantitative terms.

* Develop time dependent computer models of geothermal power plants that estimate the rate of scale buildup in plant components and the impact of scaling on plant performance and electrical output.

Four computer codes have been developed under this project and will be delivered to EPRI by the end of 1978. These codes are:

EQUILIB - An equilibrium chemistry code which analyzes a geothermal brine for scaling potential and calculates the most insoluble minerals that could form scale.

FLOSCAL - A scaling kinetics code that estimates scaling rates in a user supplied pipe geometry for several common scale types - silica, calcite, and metal sulfides taking into account flow, temperature, flashing, and hydraulic effects.

PLANT - A computer code to calculate the impact of scale buildup on performance of binary cycle or multistage flash plants using scale thicknesses inputed by the code user.

GEOSCALE - A time dependent code which uses the above three codes to "run" a geothermal power plant on the computer and calculate when and where scale buildup will cause operational problems. The user can "maintain" the plant by setting scale thicknesses to "cleaned values" at chosen maintenance intervals.

Why Does Scale Form? The common types of scale in geothermal power plants are listed in Table 1 along with the causes. All of the important chemical and hydraulic parameters which have been identified have been put into equation form and included in the EQUILIB and FLOSCAL models to calculate scaling rates.

Table 1

Why Does Scale Form?

Type	Causes (?)
Silica and Silicates	Temperature Drop Decreases Solubility, Steam Loss Concentrates Brine, pH Changes Affect Kinetics
Calcite	CO_2 Loss Increases pH, Steam Loss Concentrates Brine, pH Shifts when Fluids Mix
Sulfides	Temperature Drop Decreases Solubility, CO_2 Loss Increases pH
Iron Deposits from Corrosion	Fe^{+2} Ion Precipitates on Surfaces and in Other Scale Deposits
Carryover	Incomplete Steam Separation Results in Aerosol Carryover of Salts
Sulfates	Temperature or Pressure Changes Decrease Solubility, Mixing Different Fluids - Ba in One Stream and Sulfate in Another = $BaSO_4$ Scale

EQUILIB The EQUILIB code utilizes an expanded data base originally developed by H. C. Helgeson. This data base includes chemical equilibrium constants for several hundred aqueous phase equilibria and mineral solubility Ksp values over the temperature range of 0 to 300°C for the elements Al, K, Na, Ca, Mg, Fe, Mn, Ag, Au, Pb, Zn, Cu, Hg, Si, As, S, C, Cl, and gases CO_2, H_2S, HCl, and S. Battelle Northwest has now expanded the data base to add a number of elements such as Ba, Sr, Sb, B, F, Cr, Ni, and the gas NH_3 that are important to geothermal scaling. The EQUILIB code analyzes the equilibrium chemical thermodynamics of a single phase, 2 phase, or 3 phase geothermal fluid at any temperature from 0 to 300°C. By an iterative computer method coupled to convergence logic and criteria, the code solves the aqueous phase equilibria including oxidation-reduction, calculates gas partial pressures, corrects fluid concentrations for steam loss, calculates pH at temperature, identifies which minerals would be insoluble, and calculates the amount that would precipitate if the fluid came to thermodynamic equilibrium. This provides an estimate of the driving forces for scale formation, but does not consider kinetics.

We believe EQUILIB will find wide use. Some examples of the use of the EQUILIB code are:

* At any point in a power plant calculate if any mineral solubility has been exceeded, and by how much.
* Back calculate brine analytical data to reservoir conditions with high temperature pH, gas pressures, composition.
* Effect of exposing brine to air.
* Effect of acidification on mineral solubilities.
* Compatibility of mixed fluids.
* Compatibility of injected fluids with underground rocks.
* Define corrosion product compositions.
* Cooling tower scale control.
* If CO_2 in the air doubles because of burning fossil fuels, how does the ocean composition change?

<u>FLOSCAL</u> Once the equilibrium chemistry is calculated by EQUILIB at a node in the power plant, the kinetics code FLOSCAL is called. FLOSCAL includes consideration of plant geometry, flow rate, fluid properties corrected for salinity, gas partial pressures, and chemical kinetics equations for scale forming species. In the initial version, we are including kinetic equations for quartz, amorphous silica, calcium carbonate, and ten metal sulfides. These are initial models and some will be based on empirical observation.

The calcium carbonate deposition model assumes that wall reaction rate and transport determine deposition rate after insolubility is produced, by CO_2 loss, for example. The deposition rates for the sulfides and quartz are assumed to be determined by wall reaction rate primarily due to supersaturation caused by a temperature drop. The amorphous silica deposition rate is controlled by silica concentration, temperature, pH, and salinity.

The rate formulations take into account the total brine chemistry as calculated by EQUILIB, the departure from equilibrium, the temperature, and, in the case of calcium carbonate, the transport of the reacting species by diffusion and by turbulent mixing. The deposition is driven by supersaturation, and deposition stops as the supersaturation is removed. Rate constants for deposition are being determined from lab test facility data and field test results.

Fluid flow dynamic calculations in FLOSCAL, the PLANT Codes, and GEOSCALE use an NaCl brine model, while the chemical equilibrium and chemical kinetics calculations use a complex model for brine and cover gas.

<u>FLOSCAL Demonstration Cases</u> The FLOSCAL code has been used to simulate the BNW scale test facility, a flashing well at Cerro Prieto, and a DOE sponsored corrosion/scaling test operated on the East Mesa brine. The qualitative agreement obtained shows the developing power of FLOSCAL for predicting scale formation.

The Cerro Prieto flashing well simulation made use of EQUILIB to deduce well bottom brine composition from chemical analysis of a brine sample taken after steam separation at the well head. Brine composition was calculated by EQUILIB for the sample at lab temperature, with concentrations adjusted slightly by EQUILIB for the sample at lab temperature, to match measured pH. The steam and gases removed at wellhead separation were added back in a second EQUILIB run, and the resulting brine was brought up to well-bottom temperature in a third run with pH allowed to adjust for the temperature change as determined by the hydrogen ion equilibrium reactions. Finally, this resulting composition was supplied to FLOSCAL with instructions to bring the solution to equilibrium with calcite and quartz believed to exist at well bottom and to remove the excess of any other minerals over saturation. The resulting brine was taken as representing the brine reservoir. This technique would be applied generally to deduce reservoir composition from surface sample analysis.

FLOSCAL was used to calculate scaling rates in Cerro Prieto well M39. The spatial distribution and deposition rate subsequently calculated by FLOSCAL as occurring above the flash point in the well were qualitatively correct and sensible, but the spatial extent and rate of calcite deposition were found to depend strongly on the temperature dependence of the equilibrium constant for formation of the $CaHCO_3^+$ (calcium bicarbonate) ion in solution. It seems likely that applications of FLOSCAL will turn up other examples like this one of chemical equilibrium data requiring more precise measurement. Nevertheless, the level of accuracy obtained with the existing data base for this flashing well precipitation is probably sufficient to make FLOSCAL very useful.

FLOSCAL's predicted sulfide deposition rates in the East Mesa corrosion/scaling test are being used to iteratively refine the reaction rate constants in FLOSCAL.

GEOSCALE DEMONSTRATION TEST The binary plant version GEOSCALE code has been run with a simplified brine model in a time dependent mode. The predicted decline in power output as scale accumulates in the heat exchanger illustrates the plant performance history that GEOSCALE should be expected to predict.

CONCLUSIONS ON GEOTHERMAL BRINE CODES The family of geothermal brine codes being developed here should aid a utility in evaluating a geothermal resource, anticipating the level of scale problems, choosing an appropriate plant type, studying scale formation problems in specific plant components, evaluating chemical treatment schemes, and proceeding intelligently in geothermal energy development.

Our study of scaling has lead to some general observations on scaling in power plants:

* The heavy scaling at Niland is probably unique to that resource.

* Most of U.S. resources are medium temperature at salinities less than sea water - calcite deposition in flash systems will be the major scaling problem, if any scaling occurs.

* Calcite scaling can be controlled by use of the pressurized binary cycle concept - need reliable down-hole pumps.

* Scale in binary cycle heat exchangers will be primarily metal sulfides controllable by periodic cleaning. No kinetic studies of sulfide deposition are available, but deposition is slow.

* If designers will apply present knowledge, scaling in the power plant can be just another maintenance problem. If we don't always try to get the last BTU out of the brine, scaling can be reduced.

* A major unknown scaling problem may be waste injection well plugging.

EQUILIB SIMULATION OF ACIDIZATION FOR GEOTHERMAL SCALE CONTROL

EPRI RESEARCH PROJECT 1195-2

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Introduction and Background The chemical composition of a geothermal brine reflects the *in situ* conditions of the rock formation from which it is derived and, accordingly, varies widely both in minerals present and in total dissolved solids.

The solubility of solids in water over a wide temperature and pressure range exhibits a great variety of phenomena. These may include reaction of solid and water, solid-solid reactions, or phase transitions, and the formation of immiscible liquids. The solubility of solids within the temperature range of interest to geothermal developments may be divided into the following two general classifications:

1. Solids with solubilities which increase with the increase in temperature at saturated water vapor pressures. For these materials the solubility is high at temperatures approaching the critical point of pure water (374°C).

2. Solids which either decrease in solubility with rising temperature at saturated water vapor pressures, or at first increase to a maximum solubility, then decrease. Near the critical temperature region the solubility is usually so low that the critical temperature is raised at most by a few degrees above that for water.

Examples of the first type of behavior are the alkali metal chlorides and bromides; calcium nitrate; potassium fluoride; potassium carbonate; and cesium sulfate. Examples of the second type of behavior are lithium and sodium fluorides; lithium, sodium and potassium sulfates; sodium carbonate; calcium fluoride; calcium carbonate; and silica.

As the brine is brought to the surface and processed, its thermodynamic state changes causing chemical changes that affect the solubility of the minerals. Precipitation of a mineral may contribute to geothermal scale incrustation at various stages of the brine flow path; the composition of the scale depends not only on the initial state of the brine but also on the process used to extract the energy. Although the composition of geothermal scale will vary widely, it is likely to be composed of a mixture of silica, calcium carbonate and metal sulfides and lesser amounts of other substances. Studies have shown that scale deposition may be controlled, with varying degrees of success, through application of chemical principles, physical principles, or a combination of both. [1]

EQUILIB is a chemical equilibrium computer code which permits the user to calculate the changes in chemical species present in the solid, liquid and gaseous phases of a geothermal brine as it changes temperature, pressure, and pH. It was developed for EPRI by Battelle, Pacific Northwest Laboratories (BNW) as a component of its overall computer model for analyzing the time-dependent performance of a geothermal power plant undergoing scale buildup in plant components. Because of its ability to calculate what minerals in the brine would become insoluble as the state of the fluid is changed during a geothermal power cycle, however, EQUILIB itself is a useful tool for studying the effects of additives, pH changes, thermodynamic states, etc. on mineral precipitation from the brine.

Predictions based on thermodynamic considerations alone are, of course, limited. For example, minerals that are predicted to precipitate may not do so rapidly enough to form scale. Minerals that do precipitate may be entrained in the moving brine; the formation of scale depends on adherence and hydrodynamics as well as chemical kinetics. Further, the computer predictions are necessarily limited by the accuracy and completeness of the data base used in EQUILIB. Of particular concern are the approximations used for the activity coefficients for the various ionic species. The BNW project for EPRI will also provide laboratory data on the kinetics of scaling for use in a computer model of scale buildup. [2]

In spite of these current uncertainties, it is believed that EQUILIB can be used for parametric studies to assess what minerals are thermodynamically possible precipitants. It should be useful as a screening tool to reduce the number of experiments necessary for scale control for a specific reservoir/plant system.

In an experiment at the DOE-SDG&E test site in the Salton Sea Geothermal Field, Grens and Owen [3] found that silica scaling can be controlled by the injection of HCl to lower the pH of the high salinity brine from the nominal separator values of 5.5 to 5.8. The tests showed scaling was vastly reduced when the brine was acidified to pH 1.5, 2.3 and 4.0. Jackson and Hill [4] have also suggested acid addition for control of sulfide scale formation. Phillips, et al. [1] have pointed out that acid addition would favor removal of carbonate thus preventing formation of calcite scale.

Thus, acidification, to maintain the pH of the geothermal fluid at low values, has been suggested as a means of reducing precipitation and scaling. The treatment has been demonstrated only by bench scale tests under very limited conditions. Furthermore, acidification has undesirable features, three of which are:

1. The use of acid adds directly to operational costs in relation to the amount of acid required.

2. Addition of acid to the brine changes the bulk chemistry of the brine and means the brine is no longer in chemical equilibrium with the rock formation from which it was derived, and may cause chemical changes on reinjection, resulting in decreased injectivity.

3. Corrosion of common structural materials generally increases with acid addition.

Project Objective The objectives of this recently initiated EPRI project at Systems, Science and Software are to apply the EQUILIB code to study the effects of HCl acidification on geothermal brine chemistry, estimate scaling potential of brine at various power plant state points, indicate potential for corrosion of common structural metals and study reactions of the spent brine with reservoir rocks. No new research will be performed, but the extent of the usefulness of the code for acidization analysis will be established.

Project Work Plan The EQUILIB code has been installed on the S^3 Univac computer system and test cases run which duplicate results by BNW. A series of EQUILIB calculations have been initiated to evaluate the potential usefulness of acid addition to geothermal brine for scale control and to assess the possible associated problems of corrosion and reinjection. Specifically, the following work is planned:

1. Temperatures, pressures and compositions representative of the East Mesa and Cerro Prieto geothermal fields will be studied. The East Mesa brine is predominantly a calcite ($CaCO_3$) scale former; the Cerro Prieto brine is predominantly a silica (SiO_2) scale former.

2. Key state points for a flashed steam and a binary power plant process will be identified and the temperature, pressure and flow conditions for each plant option, state point and brine type will be computed. Batelle will perform these computations (input data for EQUILIB) using its computer program for simulating geothermal power plant cycles.

3. EQUILIB will be used to predict the brine chemistry changes at each state point and to calculate the amounts of possible insoluble phases, temperature, pressure, pH and Eh. This will be done with no allowance for removal from the fluid of the solid phases as they form (entrainment) and for the case where the minerals are removed as formed (precipitation). The planned calculations at each state point for each of these cases is depicted schematically in Figure 1.

4. The results of (3) and literature information on corrosion of common structural materials will be used to determine the likely corrosion resistance of the materials at each state point.

5. The spent fluid for each brine/power plant combination will be equilibrated (using EQUILIB) with minerals typical of the reservoir rock to determine the potential reactions with the reservoir rock upon reinjection.

6. EQUILIB will be used to titrate the East Mesa and Cerro Prieto brines at plant inlet temperatures and pressures to determine pH versus HCl addition. Known chemical reactions for carbonate and silica scales will be used to select the "optimum" amount of acid to be added to each brine to reduce by ninety percent or eliminate scaling potential.

7. The optimum amount of HCl appropriate for each will be added to the East Mesa and Cerro Prieto brines and the work in (3) through (6) repeated to evaluate the potential of acid addition for scale control and the possible attendant effects on structural material corrosion and chemical reactions of the reinjected brine with reservoir rocks. A schematic of the calculations planned with acidified brine for each of the selected reservoir/power plant systems is shown in Figure 2.

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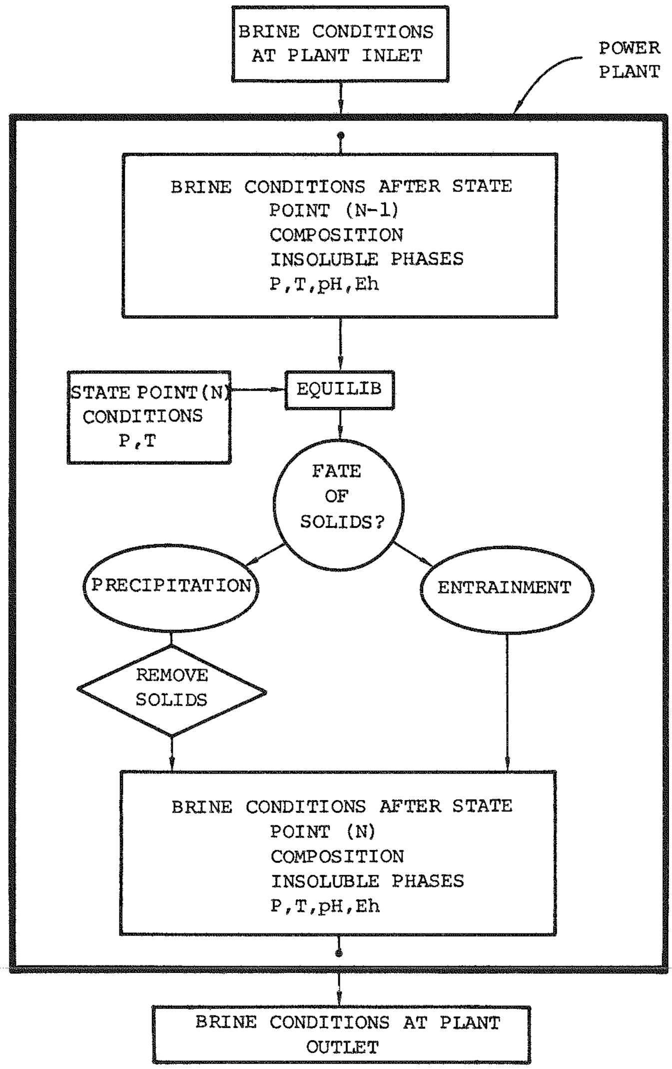

Figure 1 Schematic Calculations Planned at Various State Points for Each Reservoir/Plant System Selected.

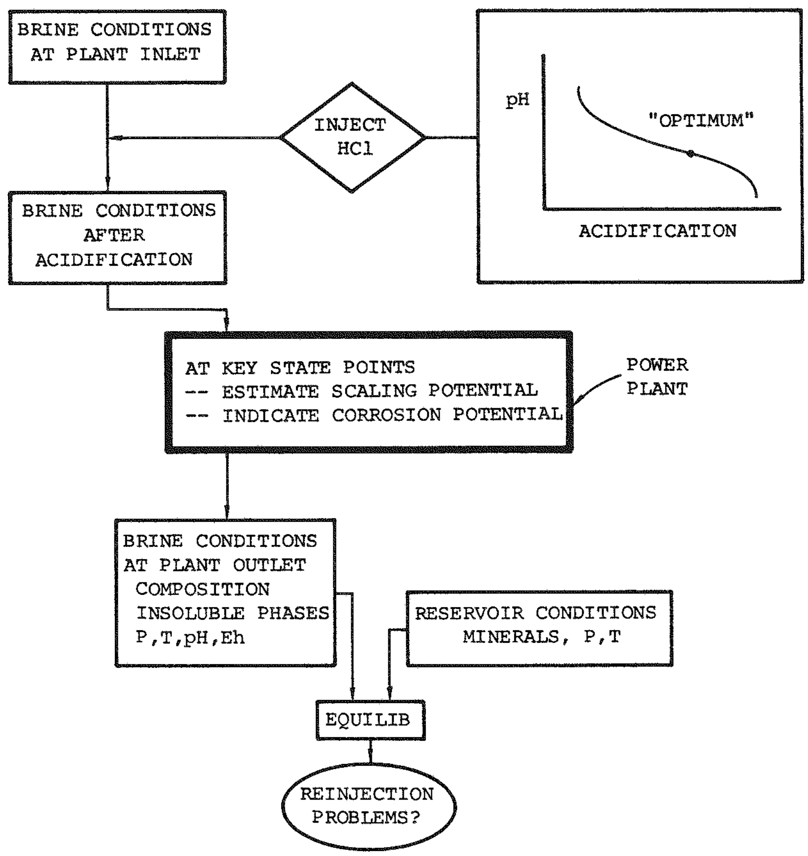

Figure 2 Schematic of Calculations Planned to Study Effects of Acidization.

BRINE-ROCK INTERACTIONS

RP 653-2

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Introduction An EPRI-sponsored experimental study of the modes of interaction of aqueous solutions with volcanic rocks from 75°-300°C, 500 bars pressure in the Dickson Hydrothermal Laboratory, Stanford University, has just completed one year's effort. The aim of the research is to provide fundamental data on kinetics of reactions and solution-solid equilibria which are needed to design various aspects of geothermal power utilization. A basis is to be provided for the evaluation of processes, such as predicting and interpreting the chemical composition of fluids that have been in contact with various types of host rocks at particular temperatures, residence times, mineralogy and rock permeability. The changes in response to changed temperatures and pressures of geothermal brines can be deduced and applied to scaling problems in pipes and power generators. The underground changes in chemical and mineralogical compositions when spent brines are reinjected can be predicted.

The reactions are done with the use of specially designed equipment in the Dickson Laboratory, which permits powdered rock to be reacted at high temperatures and pressures in an inert sample cell (teflon or gold) suspended in a pressure vessel from which internally filtered samples of solution can be withdrawn at set intervals without disturbance of the experimental conditions. The rock-solution mixtures are mixed continuously by means of a rocking device. Analyses of solutions and rocks before, during, and after reaction provide data as a function of temperature, pressure, time, solution, concentrations, and the ratio of solution to rock.

This paper presents a brief discussion of one typical experiment, together with comparisons of the results with other experiments, and a brief summary of possible relevance to geothermal systems.

Experimental Procedure Experiments are being done on the reactions of basalt and rhyolite with aqueous solutions H_2O; $NaCl-H_2O$, from 10 to 0.1 wt% NaCl, at 300°C, 200°C and 500 bars, at the rate of 12 reactions per year. The basalt is a fresh, fine-grained nearly crystalline rock from a recent cinder cone near Clear Lake, California. The rhyolite is an unaltered glass from the McDermitt Caldera, northern Nevada.

The rocks were hand ground in an agate mortar until the grains were less than 100 μm in size. Solution to rock mass ratios are three to one.

A typical experimental sequence consists of taking the experimental assembly to the desired temperature and pressure without rocking, sampling the solution, initiating the rocking, and taking a series of samples at increasing time intervals during 30 days of reaction. The experiment is terminated by rapidly cooling the equipment to room temperatures, sampling the "quenched" solution, disassembling, and recovering the remnant solution and solids for study.

Liquids are caught in a gas-tight plastic syringe attached to a valve block at the end of a lined capillary tube that connects to the reaction cell inside the pressure vessel. About 6 grams of solution are withdrawn per sampling. The solution is generally divided into three portions: for pH measurement, for major element analysis, and for trace element analysis. The major elements - Na, K, Ca, Mg, Fe, and Si - are determined by use of atomic absorption. Trace elements are determined by a special emission spectrographic method, devised by Dr. A.S. Radtke of the U.S. Geological Survey, which is capable of determining low parts per million and parts per billion levels in one gram of solution. Other specialized methods are used to determine Cl^-, $SO_4^=$, CO_2 and H_2S. A typical experiment produces about 10 samples of solution which require about 300 analytical determinations.

The solids are studied by petrographic microscopic examination of thin sections, X-ray identification of minerals, chemical analyses before and after reaction, and scanning electron microscope examination. The changes in mineralogy, bulk chemical composition, composition of mineral fractions, and textures are correlated with the changes in chemical composition of the fluids.

Experimental Results Solution Chemistry: The reaction of Clear Lake basalt with 10% NaCl solution at 300°C and 500 bars serves as a typical example. Solution compositions, presented in Table 1 and Figure 1, changed rapidly during the initial 100 hours. Beyond 100 hours some components regularly increased (Ca, K), others decreased (Mg, H^+), others remained

unchanged (Cl^-), and one (SiO_2) passed through a gentle maximum just beyond 600 hours. Clearly the solution did not achieve equilibrium with the rock even after more than 800 hours (33 days) of reaction.
The trend of each component reflects a complex interplay between the solution and solid phases as they formed and changed with time.

Alteration of Solids: The solids in the cell at the end of the reaction consisted of a fine-grained mixture of unreacted minerals with several alteration products: a clay mineral (smectite), a zeolite (mordenite), and another zeolite as yet not firmly identified. The clay appears to have formed mostly by direct conversion of previous minerals, whereas the zeolites probably grew from solution. Scanning electron microscope photographs of the mineral assemblages clearly show the textural details of the original and newly formed minerals.

Discussion of Results: During heating without rocking, which required 4 hours, the original pure NaCl solution took on moderate amounts of SiO_2 (485 ppm) and K (767 ppm), and lesser Ca (7.1 ppm). The pH dropped from the initial 6.8 to 5.5, as measured at room conditions. After rocking was started, a rapid reaction began; the pH dropped further, and SiO_2, K, Ca and Mg increased especially sharply during the first 43 hours. The pH dropped steadily to a minimum of 3.5 at 43 hours and slowly rose thereafter.

Comparison with Other Reactions: In nearly all our experiments on the reaction of various glassy and crystalline rocks with different kinds of solutions, including seawater, pure H_2O and NaCl-H_2O of several concentrations, the solutions initially became acid. The causes of the rapid input of H^+ are not well understood. Some possibilities are: (1) freeing of H^+ in minerals or on surfaces by exchange with substitutable cations such as K^+ and Na^+; (2) hydrolysis reactions of metallic ions (symbolized by M^{++}) freed to solution,

$M^{++} + n\ H_2O \longrightarrow M(OH)_n^{2-n} + n\ H^+$; (3) production of new silicates by reactions which form H^+, such as the simplified reaction,

$Ca^{++} + H_2SiO_4 \longrightarrow CaSiO_3 + H_2O^+ + 2\ H^+$; or (4) dissolution of a substance such as pyrite, FeS_2, which releases H^+, as follows:

$$FeS_2 \longrightarrow Fe^{++} + 2\ S^=,\ 4\ S^= + 4\ H_2O$$
$$\longrightarrow SO_4^= + 7\ S^= + 8\ H^+.$$

Probably all of these types of reactions go to some extent, the balance among them being set by the experimental parameters and the nature of the materials.

After initial production of acid, the solutions gradually became less acid, and some became alkaline. The acid is consumed by H^+ attack on silicate minerals, which produces phases compatible with the temperature, pressure, and compositional circumstances. Commonly smectite clay forms as a metastable phase. Smectite is a general term for a large family of poorly understood, complex clays. Montmorillonite, the most common member, has a composition

$$\left(\frac{Ca}{2},\ Na\right)_3 Al_{2-x}Mg_x[Si_4O_{10}](OH)_2 \cdot n\ H_2O$$

Non-OH-containing minerals, such as feldspar ($NaAlSi_3O_8$) are slowly attacked by H^+, which associates with $O^=$ in the mineral structure to form OH^- groups. This is a sluggish reaction; it continues until a chemical balance is achieved between the rock and solution. The acid consuming capability of the solids in part depends on the amount of rock present relative to solution. High solution-to-rock systems tend to retain greater acidity because of this effect. The initially rapidly released H^+, therefore, tends to promote the formation of more stable phases, but slowly.

The silica content of solutions characteristically exceeds quartz solubility. The SiO_2 contents of solutions of the basalt-10% NaCl experiment reached a maximum of 1825 ppm SiO_2 after 609 hours. The solubility of quartz is about 900 ppm SiO_2 at 300°C and 500 bars. This overshoot is even more remarkable when it is kept in mind that no SiO_2 solid phase is stable for the bulk composition at the experimental conditions. Apparently, the rapid breakdown of silicate minerals furnishes SiO_2 incongruently to solution, and this happens at a greater rate than any reverse reaction that takes SiO_2 from solution. The formation of low solubility silicate solid phases is a slow process. The metastably high chemical potential of SiO_2 in solution has an important effect on the formation of SiO_2-rich metastable phases, such as some of the zeolitic minerals.

The slow rise of Ca and K in solution reflects their increasing displacement from minerals by Na in response to the extremely high chemical potential of Na in solution. Mg, on the other hand, is steadily consumed by growing silicate minerals.

The alteration products tend to be extremely fine grained, of the order of 10 µm. Probably the first products, produced early in the reaction, are nearly amorphous. With the passage of time, the solids coarsen, develop more ordered crystal structures, and undergo phase changes. The combination of changes in the solid phases leads to readjustments of solution compositions. The levels of trace elements in solution are particularly sensitive to these types of changes. It may prove possible to use trace element contents of natural fluids to identify the nature of terrains from which the fluids originally came.

Relation of pH to Rock Type and NaCl Concentration: The pH at 800 hours depends both on solution type and rock type, as Figure 2 illustrates; rocks with high silica contents (rhyolite) produce higher pH's in solution than low silica rocks (basalt). High concentration NaCl solutions show lower pH values, all other factors held constant, than low NaCl concentration solutions.

Pure H_2O Reactions: Reactions of pure H_2O with volcanic rocks differ from reactions of NaCl solutions. Initial reactions put extremely high levels of SiO_2 into solution, of the order of 5000 ppm SiO_2 or higher. Indeed, sampling such solutions is made difficult because amorphous silica can precipitate in syringes and in the exit tubes. Although the solutions initially become slightly acid, as do NaCl solutions, they steadily move toward alkalinity. With increasing alkalinity, the silica content drops; for example, after 6 weeks (1000 hours) of reacting powdered rhyolite glass with H_2O at 300°C and 500 bars, the SiO_2 content of solution had fallen to about 1350 ppm, the solubility of cristobalite. Spherulites of cristobalite were found in the solid reaction products. This happened even though the rock powder contained minute quartz crystals, which are more stable than cristobalite, and which could have served as nuclei for growth of quartz.

The behavior of SiO_2 is analogous to the behavior of H^+; an initial dissolution reaction that took place at a rate not countered by growth of SiO_2-rich phases. Strong kinetic barriers to crystal growth exist, especially under acid conditions. The reactions that eventually produce alkaline solutions seem to favor nucleation and growth of minerals such as feldspar and cristobalite. To understand the mechanisms whereby H^+ and OH^- ions influence crystal nucleation and growth is very important to geochemistry and to geothermal systems.

Conclusions Although the overview of applications to geothermal processes awaits completion of experiments, present data permit some comments to be made on potential relevance of the studies to geothermal processes.

First, rocks react rapidly with solutions. Minerals of rocks tend to break down to more stable assemblages, with accompanying major changes taking place in solution that reflect the sequence of mineralogical events. Compositions of natural solutions give information on compositions of host rocks, provided appropriate experimental data are available.

Second, even at 300°C and with the thorough mixing of solids and liquids in our experiments, none of the systems attained equilibrium during 30 days of reaction. Some experiments developed minerals that were clearly unstable; others partially converted to some stable minerals, leaving important fractions of the rock unreacted. In contrast, the very long reaction times of natural systems permit some approximation to equilibrium. However, during the exploitation of geothermal fluids for power generation, perturbations in flow rate, pressure, temperature and fluid compositions are created which result in deviations from any near equilibrium conditions that may have existed. Processes that take place in perturbed geothermal systems may be analogous to the processes deduced from the experiments.

Third, glassy rocks break down under attack by hot solutions, and extremely fine, nearly amorphous hydrated alteration products are created. The possibility exists that in nature such find matter may remain in suspension and be transported farther along the flow paths, possibly to deposit in rock pores. Porosity and permeability would thereby be reduced. Planning of reinjection systems should take this factor into account.

Fourth, the growing body of kinetic data resulting from the experiments provides a basis to model geothermal system behavior. Studies of the kinetics of reactions provide knowledge of the step-by-step sequence of chemical events by which nature carries out processes, whether they are equilibrium or non-equilibrium in nature. Models based on equilibrium considerations alone may prove to be limited in their applications.

Sample	Cum. Time (Hrs.)	pH at Room Cond.	SiO_2	Ca	Mg	K	Cl
0		6.8	--	--	--	0.9	63500
1	0	5.5	485	7.1	--	767	64500
2	1	5.3	1183	100	--	1603	65600
3	22	4.6	1422	143	2.8	2538	64900
4	43	3.5	1566	171	5.3	2832	66100
5	90	4.3	1663	207	3.8	2882	65700
6	187	4.4	1716	200	4.3	2850	65100
7	419	3.9	1780	226	3.2	2949	64500
8	609	4.4	1825	247	1.9	3033	64900
9	823	4.7	1762	294	1.0	3103	65000
10	870	4.7	1724	307	0.8	3155	65200

Table 1 *Experimental conditions and selected solution compositions of 10% NaCl solution reacted with Clear Lake basalt at 300°C and 500 bars.*

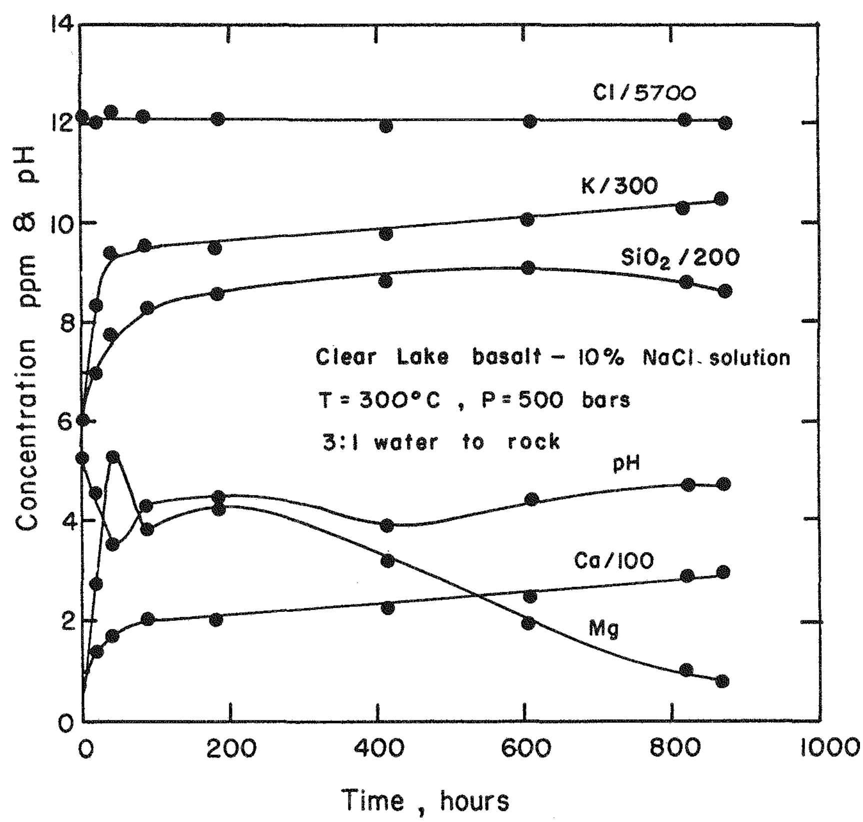

Figure 1 Variations of selected solution parameters with time for the reaction of powdered Clear Lake basalt with 10% NaCl solution at 300°C, 500 bars, 3:1 solution to rock mass ratio.

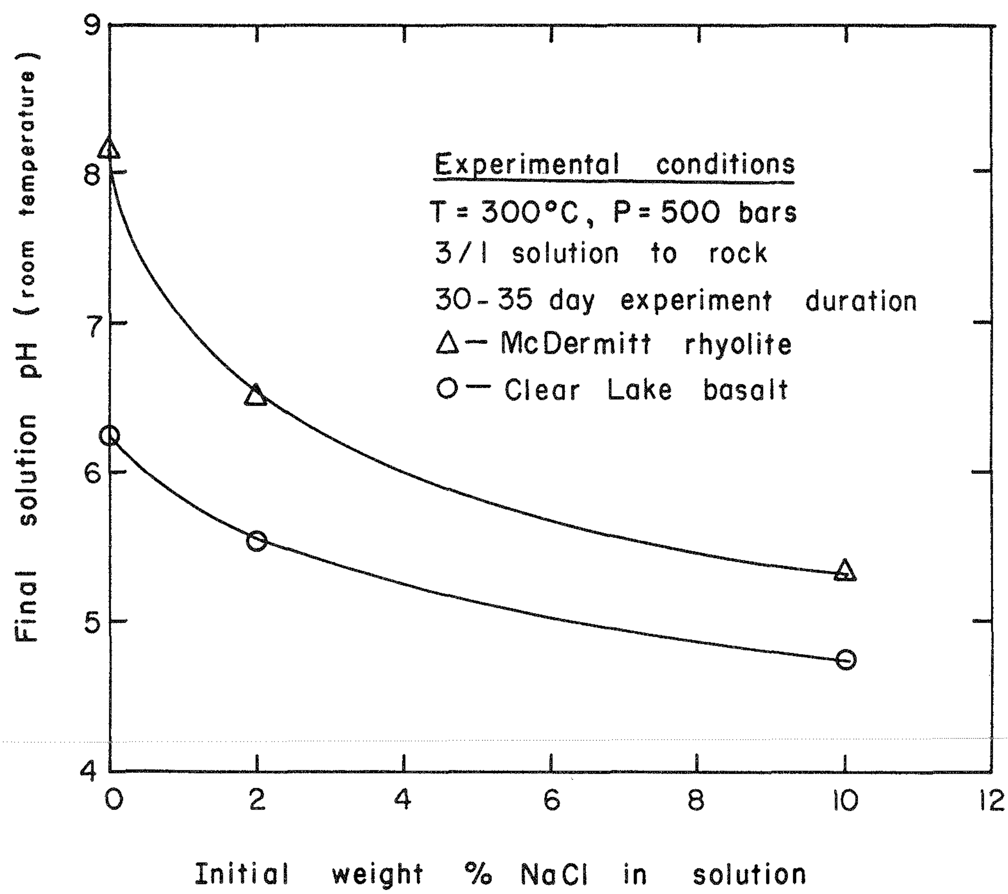

Figure 2 Variation of pH with NaCl concentration for powdered McDermitt rhyolite and Clear Lake basalt, 300°C, 500 bars, 3/1 solution to rock mass ratio, 30 to 35 days reaction time. The pH values were measured at room conditions.

UPSTREAM REMOVAL OF H_2S FROM GEOTHERMAL STEAM

EPRI CONTRACT NO. RP-1197-2

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Abstract A process is under development for removal of more than 90 percent of H_2S and other noncondensable gases from geothermal steam upstream of electrical generating equipment. The process involves condensation and re-evaporation of the steam in a single heat exchanger unit. Noncondensable gases are separated from the condensate, to be either reinjected or processed for alternative means of disposal.

I. Summary This project provides for field testing on a small scale of a unique heat-exchanger process for the removal of H_2S gas from geothermal steam. The test unit will be operated at the Geysers geothermal field on a test pad provided by Pacific Gas and Electric Co. (PG&E).

The heat exchanger process removes almost all of the noncondensable gases from the geothermal steam upstream of the turbines. Of primary importance, between 90 and 99 percent of the H_2S gas is removed, depending on the process conditions at which an optimized design is established. The process is described in more detail in Section II. The primary advantages and disadvantages of the heat-exchanger system are summarized below. First, the proposed process has three points of potential application in a geothermal power plant, as follows:

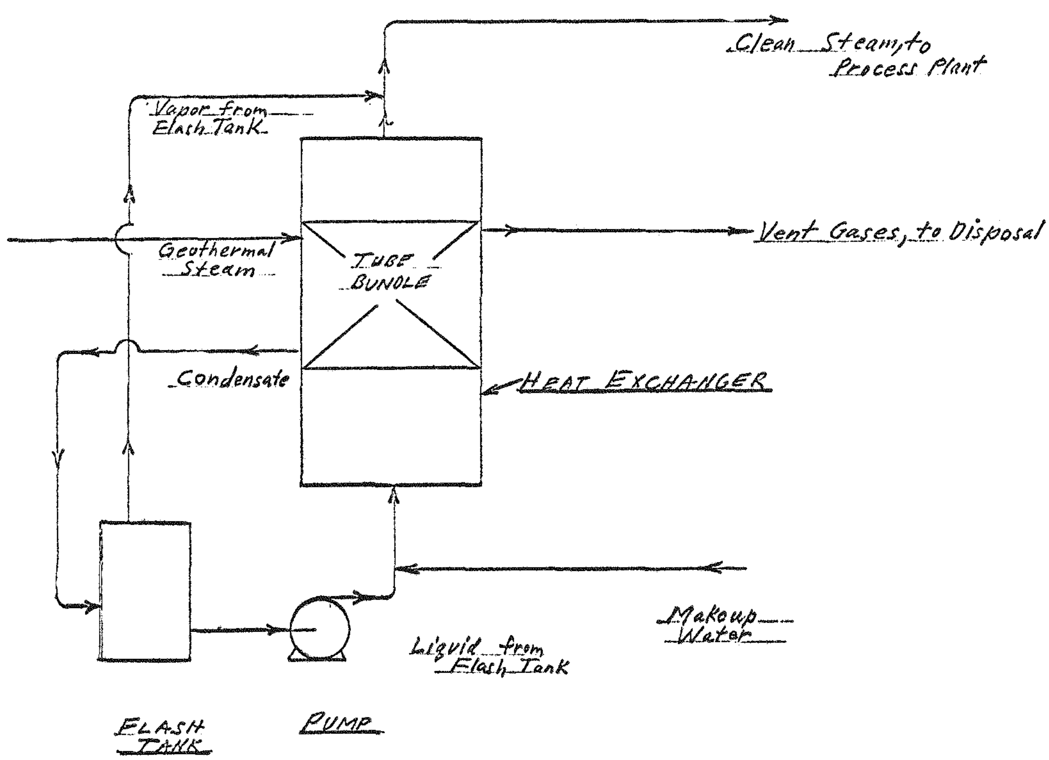


FIGURE 1
SCHEMATIC DIAGRAM OF H_2S REMOVAL PROCESS

(1) as an upstream retrofit system for existing geothermal power plants;

(2) for initial installation on new power plants instead of surface condensers downstream of the turbine;

(3) for portable, temporary utilization on new wells, even in remote areas, that are being tested by blowing to the atmosphere.

The primary advantages of the proposed process are:

(1) over 98% of all noncondensable gases, and 90 to 99% of the H_2S, are removed from the steam feed to the turbine;

(2) a simple, independent unit is installed at each turbine site;

(3) heat-exchanger equipment is utilized that is similar to equipment normally found at power plant installations;

(4) the system is self-operating, and requires only limited operator surveillance;

(5) maintenance requirements are limited; control systems are simple;

(6) steam consumption in the vacuum system is reduced, because the noncondensable gases are removed from the system upstream of the turbine;

(7) all residual solid particles should be removed from the steam; and

(8) when applied to a new geothermal power plant, the process reduces the costs for condensers on the exhaust steam from the turbine.

Disadvantages of the system are:

(1) reduced power production due to reduced steam pressure and perhaps reduced flow rate;

(2) the production of saturated steam as turbine feed instead of superheated steam, where such is presently available;

(3) the concentrated stream of noncondensable gases may have to be treated in a conventional sulfur producing plant; but in the proper geologic environment, the vent gases could be reinjected with cooling tower blowdown.

II. Process Description

A. General Description The proposed process removes almost all the noncondensable gases from the steam feed to the turbine. This is accomplished even in the presence of ammonia in the geothermal steam. The process is shown schematically on Figure 1.

Geothermal steam from the wells is almost completely condensed within the shell-side of a heat exchanger, at its saturation pressure. The condensate will dissolve some of the noncondensable gases contained inthe steam, but about 98 percent of all the gases, including CO_2, NH_3, H_2, and N_2, will remain in the vent gas stream. Over a typical range of geothermal steam compositions and process operating conditions, 90 to 99 percent of H_2S will remain in the vent stream.

The condensate, which is essentially gas-free, is reduced to a lower pressure and allowed to flash in the tube-side sump of the heat exchanger, which is maintained at a lower pressure than the saturation pressure of the inlet steam; this provides the necessary temperature driving force across the heat exchanger. The condensate is then completely vaporized within the tubes, and the resultant clean steam is sent to the turbine.

Because about 99 percent of the CO_2 in the geothermal steam has been removed from the turbine feed, as have essentially all of the light gases such as hydrogen and methane, the load on the condenser steam-jet system has been significantly reduced, and the quantity of steam that bypasses the turbine to run the vacuum system can also be reduced. Accordingly, more steam is available for the production of electric power.

In addition, most of any solid particles originally present in the geothermal steam will either remain with the vent gases, or could be removed from the liquid stream by filtration downstream of the condensate recirculation pump.

The size of the vent gas stream will depend on the amount of noncondensable gases originally present in the geothermal steam. Preliminary calculations indicate that the quantity of steam vented would be in the range of one to four percent of the initial geothermal steam when the inert gas content is in the range of 2,000 to 6,000 ppm. Compensating for this steam loss, the amount of steam that would be consumed in the vacuum system is reduced accordingly.

The final design will be strongly influenced by the total quantity of noncondensable gases, the composition of these gases, and the steam pressure. The heat-exchanger design would be optimized for each power plant according to the gas content existing at that point. Optimization procedures are discussed in subsection G.

B. Specific Unit Design The general process objectives described in the previous section can be achieved with several types of heat-exchangers. Large evaporators with a surface area in the order of 50,000 square

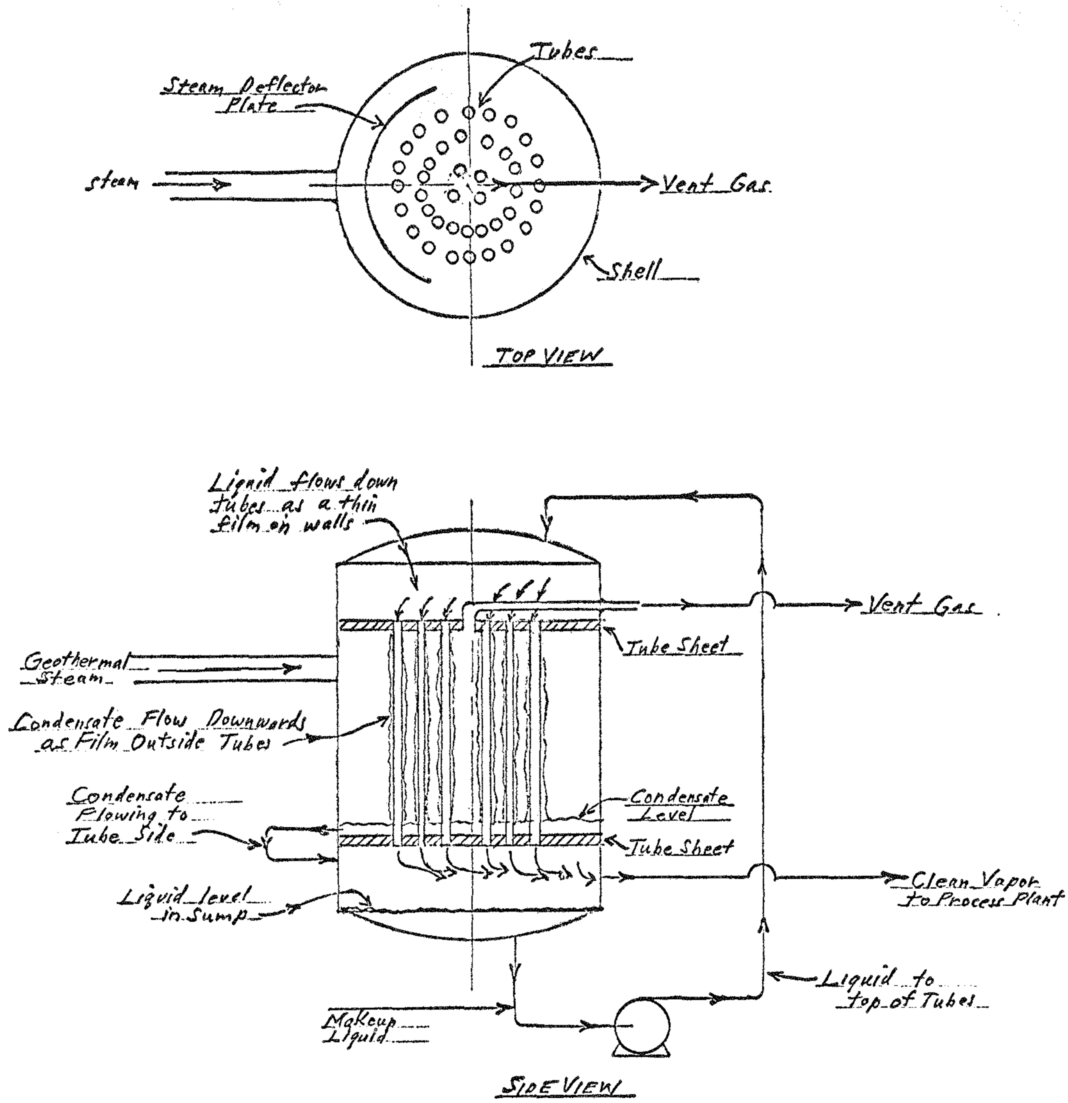


FIGURE 2
EXAMPLE OF MULTI-STAGE CONDENSATION

feet are required. Based upon a review of several design possibilities, the falling film, vertical tube evaporator (VTE) has been selected for small-scale field testing and for preliminary evaluation of full-scale process designs. The VTE has seen extensive commercial application in size ranges approaching those required for this application, and would not require significant changes from the current state of the art.

A cut-away view of the operation of a VTE exchanger is shown in Figure 2. Steam entering on the shell side condenses on the outside of the tubes. The condensate flows down the tubes and collects on top of the bottom tube sheet. The condensate flows through a pressure reducer directly to the liquid sump, where it partially flashes to vapor. Recirculating condensate from the sump is pumped to the upper head of the exchanger and is distributed to the inside of the tubes. The liquid flows by gravity as a thin film on the inside tube wall, and evaporation takes place from the free liquid surface. Only a fraction of the liquid vaporizes during a single pass so that the tube wall is never dry.

As the steam condenses, some of the CO_2, H_2S, and NH_3 will enter the liquid phase. The amount of these gases that can be absorbed by the condensate at equilibrium is controlled by three factors: the partial pressure of the gas in the vapor phase, the mass ratio of vapor to liquid in contact with each other, and the pH of the liquid solution. The pH, however, depends in a complex way on the amount of gases that dissolve. The pH decreases due to hydrolysis of CO_2 and H_2S in the liquid phase:

$$CO_2 + H_2O = H^+ + HCO_3^-$$
$$H_2S = H^+ + HS^-$$

while the dissolution of ammonia leads to the capture of hydrogen ions and an increase in pH:

$$NH_3 + H^+ = NH_4^+$$

Thus, when no ammonia is present, the pH of the liquid falls rapidly to the order of 4.5 to 5.0 due to the absorption of only CO_2 and H_2S. This low pH effectively limits the H_2S solubility in the condensate to very small amounts. On the other hand, in the presence of ammonia, the simultaneous absorption of both acid and basic gases tends to increase the pH to values in the range of 5.5 to 6.5, and the amount of H_2S that is absorbed by the condensate increases as well.

A design for radial flow of steam and gases has been proposed. A typical tube bundle would be of the order of 9 feet in diameter with about 190 tubes in the outermost circumferential layers. The number of tubes in each interior, circumferential layer would decrease progressively, such that there would be about 20 layers. The nature of the radial flow path of steam through this bundle provides a multi-stage condensation process. That is, at the outermost layer of tubes, only a small fraction of the steam (about 6 percent) would condense. This small amount of condensate will be in contact with a large amount of steam (about 94 percent of the original steam). Therefore, the equilibrium amount of H_2S in the condensate forming on this layer of tubes would be very small because of the low ratio of condensate to steam. At successive tube layers, the ratio of condensate to steam increases steadily, so that relatively more H_2S condenses at each layer. In a typical case, wherein 6.9 percent of the initial H_2S ends up in the condensate stream, only about 0.06 percent of the initial H_2S is absorbed on the outermost layer of tubes and about 1.8 percent is absorbed on the innermost layer, with intermediate amounts being absorbed on interior layers. This system design, because of its multi-stage aspect, leads to a much greater removal of H_2S than would be achieved in a single stage condensation unit, in which case over 80 percent of the H_2S would enter into the condensate.

The flow pattern of liquid in the proposed design also is partially counter-current, in addition to being multi-stage. With respect to each tube, the condensate forming on the top of the tube flows downwards and mixes with condensate forming on the middle and bottom portions of the tube. As a result of this action, less H_2S absorption will occur in the bottom portion of the tubes in any circumferential layer than would occur with a simple multi-stage unit. Overall, the H_2S removal rate is increased by this effect.

C. Calculation of H_2S Removal Rate

A series of equilibrium calculations, the results of which are depicted in Figure 3, determine the fraction of H_2S in the steam feed that would be absorbed by the condensate and eventually returned to the turbine. These calculations were made for the simple, multi-stage condensation system and did not take credit for the beneficiary effect of counter-current flow on each tube. The H_2S content of the steam was varied between 100 and 1,000 ppm, while the CO_2 content was held at either 3,000 or 5,000 ppm. Two levels of NH_3 concentration were evaluated, including zero ammonia and equal concentrations of NH_3 and H_2S. In addition, it was assumed that 50 ppm each of nitrogen, hydrogen, and methane were present. The fraction of H_2S remaining in the condensate (and entering the turbine) ranged from 3 to 10 percent, but percentages above 5 percent occur only for the unrealistic cases of very high ammonia concentration in the feed.

D. Applications of the Proposed Process

1. Power Plant Service The proposed process has three points of applications at the Geysers or any geothermal plant. First, it can be easily retrofitted to existing power generation stations by tying the heat exchanger into the steam-line upstream of the turbine. Secondly, it can be used with new power generating stations, and is believed to present a much less costly alternative to shell-and-tube condensers installed downstream of the turbine. There are two reasons why the upstream unit would be less costly; (1) higher heat transfer coefficients can be achieved in an upstream unit because of its higher operating temperatures; and (2) the higher density of the pressurized steam permits higher mass felocities, and smaller bundle sizes, in an upstream unit. Finally, the penalty due to decreased power production may not be a significant factor when compared to a downstream unit; the latter installation calls for a higher turbine back pressure than is the case with a direct-contact condenser, and requires more steam to run the vacuum system.

2. Wellhead Application for New Wells The third application of the process would be to newly drilled development wells or discovery wells. These wells are usually blown to the atmosphere for a period of time for testing purposes. It would be of value to have a simple, inexpensive and reusable unit for H_2S removal from the steam that could be easily installed at the wellhead. A small, portable heat-exchanger and pump operating as described above would be well suited to this purpose. The optimization criteria are significantly relaxed for the wellhead service application, so that the heat-exchanger could be very small and skid-mounted for easy field installations.

E. Final Disposal of H_2S The proposed process yields a concentrated, low volume gas stream at an elevated pressure which contains over 90 percent of the initial H_2S. Several means of disposing of this stream can be considered, depending on the local circumstances. Reinjection into outlying areas would be a possibility with some geological formations; this is more likely to be applicable to a hydrothermal system than to the vapor-dominated system found at the Geysers. When reinjection is not possible, the gas stream could be directed to a traditional H_2S removal unit, utilizing the Stretford, Klaus, or some other process for conversion to sulfur.

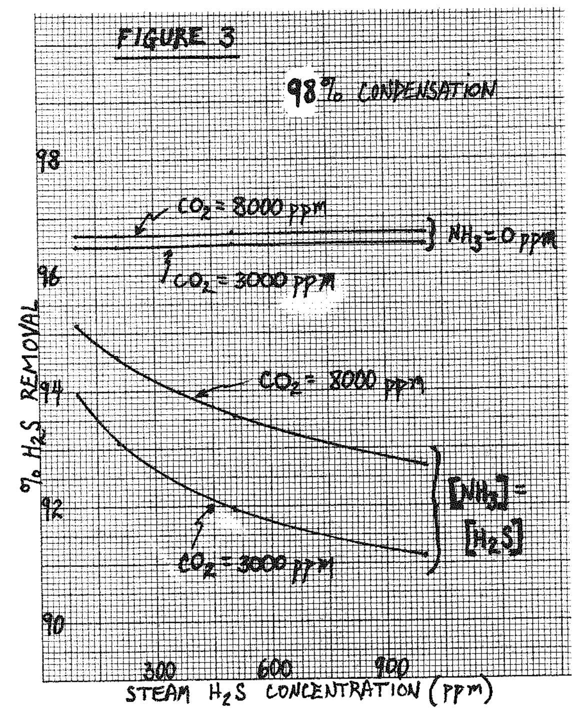
F. Projected Process Costs and Process Optimization The actual size and cost of the heat exchanger would be determined on the basis of an optimized design wherein the equipment capital cost is balanced against the reduction in power production incurred because of reduced steam pressure. The pressure loss across the heat exchanger can be reduced, thereby increasing the amount of electricity produced. In so doing, however, the temperature driving force for heat transfer is also reduced so that the heat exchanger becomes larger.

The exact optimization procedure is complex and depends on many factors beyond the scope of this study. These factors include the actual temperature, pressure and composition of wellhead geothermal steam; the inlet pressure to the turbine; the annualized cost of capital; and the cost of electricity produced using other fuels.

Although no attempt has yet been made to develop an optimized design, preliminary estimates have also been made of the equipment and operating costs for a typical design case. The major costs of the proposed system will be associated with the heat-exchanger and pumps. On this basis, the cost of a unit for a 50 megawatt power plant utilizing one million pounds per hour of steam is estimated to be in the range of 1.4 to 1.9 million dollars. The cost of a portable unit suitable for wellhead operation, with a steam production rate of 100,000 pounds per hour, is estimated to be about 50 thousand dollars.

Operating costs, other than the cost associated with reduced power production which are discussed below, are expected to be very small. Only occasional operator surveillance will be required, and maintenance needs should be minimal. No chemicals will be required nor are there special disposal problems. The recirculating pumps will be of the order of 50 horsepower for a 50 megawatt unit. Additional small horsepower consumption may be required for miscellaneous purposes, such as the feeding of makeup water.

The capital costs indicated above are associated with electric production losses of an estimated 2 to 3 percent in the worst case. This worst-case calculation assumes that nothing else would be done for H_2S abatement; it does not take credit for losses that would otherwise be incurred by the alternative retrofit systems for H_2S control, nor does it take credit for the power loss that would result from using surface condensers on new power plants. It is probable that the electric power losses for the proposed process would be no greater than the losses from any alternative H_2S removal system, and that total costs would be reduced.



ENERGY RESOURCES IN NICARAGUA

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Preamble I feel honored to participate in this scientific event of the Electric Power Research Institute (EPRI). President Anastasio Somoza D. designated me to express his greetings and his admiration to the relevant efforts of EPRI to search for new energy sources.

Introduction Nicaragua, located in the heart of Central America, lies directly on the Circum Pacific belt of fire. Because of its distinctive geologic features related to the Circum-Pacific Tectonic Belt, Nicaragua has been called the Land of Lakes and Volcanoes. Its beauty enhanced by many active volcanoes and lush tropical growth has been appreciated by visitors and residents alike.

During the early development of the country, fuel requirements were satisfied by using wood much the same as other nations. However, beginning in the late 1920's with an increased availability of petroleum, wood became relegated for use mostly in rural and suburban areas, where it is still used for cooking, but rarely for industry.

The country has no known petroleum resources; however, oil companies prospecting and drilling on the Atlantic shelf have found interesting indications of possible fields.

Hydro energy was not used very much until 1965 when the first power plant over 10 MW was put in service. Before then, only small units had been used for coffee mills, rice mills, and gold-ore mills, located mainly in the Central Region with some on the Atlantic Coastal Plain. Many of these have never been dismantled.

There are no known resources of coal nor of uranium.

Today the National Interconnected System of Nicaragua has a total installed capacity of 300 MW, with 67 percent thermal plants and 33 percent hydro plants. This system serves about 90 percent of the total electricity market. Our system has already been interconnected with the Honduras system to the north, and will soon be connected to Costa Rica to the south to improve reliability and make use of secondary energy availability.

Energy Market Present energy sales is 1000 Gwh per year, of which, roughly, 60 percent is for industry, irrigation, and services, 25 percent for residential, and 15 percent for other uses.

The market has been increasing 11-13 percent per year, and all indications are that this will continue. Average electricity retail prices have gone up from 2.7 US cents per KWH in 1973 to 6.0 US cents per KWH, with the probability of increasing even more in the near future.

For the last two years Nicaragua has suffered severe droughts which have forced us to generate over 90 percent of our electrical energy with imported petroleum products.

The imported petroleum products used as fuel have come to represent a whopping 17 percent of total imports in 1977 as compared to 4 percent in 1970 due both to increased consumption and to the dramatic increase in prices during the last few years.

These problems are common to other countries, both developed and developing. But they are compounded for the less-developed countries because of the unavailability of adequate financial resources needed to allow the rapid development of indigenous sources.

Energy Policy The Nicaraguan electrical energy policy has been oriented toward promoting consumption in the industrial and agricultural sectors, while discouraging excessive consumption by large residential users.

The Government is promoting the integration of marginal geographical areas to the economic activity of the country through a program of rural electrifications. With the implementation of this policy, the Government expects to contribute effectively to increase the Gross National Product by a minimum of 6 percent per year.

The Energy Crisis brought about by OPEC countries is undoubtedly causing all other countries to revise their energy policies and has helped to emphasize the need to develop other energy sources. This crisis intensified the effort of all mankind to search for and commercialize new energy resources. This, obviously, must also be the policy of Nicaragua.

With this energy scenario we have launched an urgent program for developing indigenous renewable resources.

To find these resources in the form of hydro, geothermal, and biomass, we are proceeding with a study to locate and make a comprehensive inventory of all potential sites.

An Energy Plan The Energy Plan is the first general look at the energy resources of the nation, and the purpose is to catalog and rank these resources for development. Primary reliance will be given to the development of hydroelectric power and geothermal power, with the objective of reducing foreign exchange requirements for fuel oil.

The largest energy resource potential presently appears to be hydroelectric power, located mostly in the Central Mountain Area and the Atlantic Coastal Plain. The total hydro potential is probably of the order of 4000 MW, compared to a present peak load of about 200 MW. Some 100 sites for plants larger than 20 MW have been located and investigated in the field. A detailed comparative evaluation of various dam-sites and their orientation is now being accomplished with the objective of developing a hydro-power catalog of potential sites for use in subsequent planning.

At the same time, intensive geothermal investigations are being undertaken in the Nicaraguan Graben, where the most active volcanism and thermal manifestations are found. However, hot springs in the vicinity of young volcanoes in the eastern part of the country are also being sampled to determine whether further investigations appear warranted. Preliminary findings indicate there may be geothermal potential, as well as hydro potential, in the eastern part of the country.

An overview of the Energy Plan first requires an overview of the country. Nicaragua has an area of 42,000 mi^2, about one-fifth the size of New Mexico. It is divided by a central north-south trending mountain range into three geographic regions: the Atlantic Coastal Plain in the east, the Central Mountain Zone, and the Pacific Lake Region in the west. The Atlantic Coastal Plain is under the influence of low-level warm and moist easterly tradewinds from the Atlantic and Caribbean and receives precipitation all year round. There is a general decrease in mean rainfall and unit runoff on the Atlantic side of the mountains with distance from the coast and increasing altitude.

Precipitation amounts range from 6 meters (20 feet) along the southeastern Atlantic Coast to 1-1/2 meters (3-5 feet) in the Western Lake Region.

The Atlantic Coastal Plain rises gradually from the coast for about 100 km, at which point the foothills begin. The vegetation of this region is largely dense tropical rain forest with some pine-savannah in the Northeast. Ten major rivers originate in the mountain region and flow easterly through the rain forest.

These rivers discharge annually an average of 100 billion cubic meters to the Atlantic, which is comparable to five times the long-term mean discharge of the Colorado River at Lees Ferry, Arizona. These rivers represent, in combination with Lake Managua and Lake Nicaragua, the nation's primary water resources available for development. However, only one-third to one-half of this volume occurs where it can be developed for hydropower. The problem with the portion which is lost is that it originates in runoff close to the coast, where good dam sites are sparse and potential heads are very small. In addition, we share some of the waters of two large rivers on our borders, with Costa Rica to the South and Honduras to the North. These rivers with an additional total of over 40 billion cubic meters annually, represent another opportunity for development.

Consequently, the best combination of exploitable head and discharge for hydropower is generally found at sites with intermediate elevations in the range of 80 to 350 meters above sea level.

Before reviewing possible power development schemes, I would like to briefly note some facts on population distribution and economic activity throughout the country. An understanding of both is necessary to place energy development in its proper perspective.

Population and economic development seem to vary inversely with rainfall, or more exactly, with rain forest density. The total population of Nicaragua is slightly over 2.3 million. Except for the coastal ports and several mining centers, the Atlantic Coastal Plain is sparsely populated, with only about 8 percent of the population. The North Central Mountain area has about 30 percent of the population and the remaining 62 percent live in the western and drier part of the country. The present road network is roughly proportional to the population density in the three zones or more correctly, proportional to the socio-economic activity found in each of the major geographic zones.

The highest mountains lie in the north central part of the country and this area thus figures importantly in planning for hydro-electric development, since it is here where the highest heads can be developed. Our first hydroelectric projects were constructed in this region with a firm power rating of 40 MW. This region is important for production of coffee, sugar, fruits, and has a significant meat and dairy industry. There are 55 towns in the region ranging from 2000 to 70,000 population, many of which are supplied with power from the national grid.

The Western Lake Region or the Zone of the Pacific has a population of over 1.4 million.

About one-third of these people reside in Managua, the capital city, and the remainder live in 19 cities and towns ranging from 15,000 to 105,000 population. This is the principal industrial, commercial, and agricultural region of Nicaragua. Sugar, coffee, and cotton are the major crops, and cattle and meat production are also major agricultural activities. Large irrigated farms are found in this region. However, over 1,000,000 additional hectares could be brought under irrigation if water could be economically supplied, provided a market existed for the production.

Industrial and commercial activity are the primary source of jobs in this region and, in turn, constitute the largest demand for electric power. It is fortunate that our principal geothermal resources are in close proximity to these load centers.

On the other hand, hydro resource sites on the Atlantic side are relatively distant from the load centers. We also observe that planning the development of the nation's water resource requires solution of a conflict between using water solely for hydroelectric power or for hydroelectric power and other uses. From a water resources system point of view we have found that it is technically feasible to interconnect many of the eastern reservoir sites and bring their waters to the west in a transmountain diversion. This would permit irrigation and other uses in the Pacific Zone in addition to hydroelectric power development.

However, from an economic point of view, many additional questions have arisen. For instance, can water be diverted to irrigable land at a competitive price? Nicaragua sells its agricultural production in the world marketplace and must be competitive.

In this regard, the commercial and industrial sectors offer alternative means of reaching national goals of higher employment and improved standard of living. Our labor force has been found to be highly competitive in industrial work and thus has contributed greatly to the development of our Free Trade Zone, where goods are manufactured by foreign companies for subsequent export. Expansion of the Free Zone is thus considered a prime economic objective since it will not only provide needed jobs but needed foreign exchange.

Yet another economic factor that is intertwined with water and power development is that construction of the hydro system in the Atlantic Region itself will involve solution of difficult access problems in sparsely settled rain forest areas. This leads to the development of roads, infrastructure and generally increased economic activity in this region, particularly the ports. This represents a long-term development objective of the country.

<u>Multi-Objective Planning</u> The complexity of inter-relationships between energy and water resources development and economic development in Nicaragua has led us to introduce multi-objective planning techniques, which can be used to focus more on the fundamental problems of the country, i.e. improvement of the general welfare, improved employment, resulting in a better standard of living.

We have concluded that we must plan not simply in terms of expansion of the power system but rather in terms of expansion of the national economy itself. In this framework, both power and water resources become part of the required infrastructures to support achievement of basic national socio-economic goals. Our aim will be to develop, in coordination with other government agencies and the private sector, a plan for long-term economic growth and related energy load growth that relies primarily on private economic investment, but with the necessary blend of infrastructure to provide the opportunity for free enterprise to flourish.

We recognize that the character of the electric power system in terms of the quantity and quality that are provided will affect the types of industry we can attract to Nicaragua. This is an important aspect which will constrain the economic industrial options available. We are therefore attempting to evaluate the cost to consumers of loss of power and voltage fluctuations, and in turn what this could mean to the economy in terms of lost jobs. This approach will permit us to economically justify and finance system improvements to achieve a quality of service that is in tune with the economic development needs of the country. This will generally mean upgrading our system since many of the job-producing industries we hope to attract are organized for production on the basis of reliable power service.

The development of the water and water-power resources of the country will thus involve long-term considerations that transcend all sectors of the economy; we have begun laying out alternative system designs considering discharge of all divertible waters together with irrigation alternatives, and various combinations thereof.

We are optimistic that geothermal resource may be sufficiently large to meet our near-term needs for system expansion, since geophysical investigations being done under the energy plan appear to indicate new and unexpected potential geothermal sources in the vicinity of Managua. If this expectation materializes, it will be important to Nicaragua, since these resources can be developed in smaller increments, and generally over shorter time periods than most of the hydro.

Geothermal Investigations of the Energy Plan The detailed geothermal investigations cover an area of approximately 20,000 km^2, near the Marrabios Range and along the Nicaraguan Graben. This includes the westernmost chain of active volcanoes, the Nicaraguan Depression, and the ancient volcanic chain, paralleling the present volcanic chain. This area is being geologically mapped. A geochemical program of sampling hot springs, warm water wells, and cold water sources was undertaken within this area.

To assist in interpretation of the geochemical data, a hydrogeologic program is presently in progress to establish possible mixing models of shallow subsurface cold waters with the waters of the hot springs. Water samples are also being prepared for later isotope analysis to aid in the study of recharge of geothermal reservoirs.

Reconnaissance geophysical investigations utilizing magnetotelluric and roving vector tellurics on stations spaced approximately 5 km apart are in progress and are being utilized to indicate areas of high conductivity.

The geochemical data are being compiled for selection of areas for followup detailed geophysical investigations. It is anticipated that utilizing these data we can establish the presence and location of high temperature reservoirs. Completion of this phase of investigations will be followed by temperature gradient drilling to determine heat flow.

Some further comments are called for in regard to geological and other results obtained to date. First (as can be seen on the map of Nicaragua) thermal springs and similar features are found in practically all parts of the country. The major concentration of the thermal manifestations are associated with, or in close proximity to, the active volcanic chain, paralleling the Pacific Coast. Thermal manifestations found in other parts of the country and particularly those on the east coast are all associated with older Quaternary volcanism. The volcanic activity near the East is evident as small cinder cones or as calderas.

As a result of these investigations we have found certain areas that offer attractive characteristics for future geothermal development. These areas are Momotombo, San Jacinto, El Hoyo, and Volcan Santiago.

Momotombo Field The history of the geothermal development in Nicaragua began formally in 1966, when the first technical evaluation mission from Italy arrived to determine if the existing sites with surface manifestations could be commercially developed in the future.

During 1969, with the valuable help of the United States through AID, more detailed work was carried out by American scientists. The first significant geothermal well in Nicaragua was drilled at Momotombo, which proved the existence of commercial energy at that site. In 1972, the Nicaraguan Government signed an ambitious agreement with the United Nations for further work, both at Momotombo and San Jacinto. However, the earthquake of December 1972 destroyed the capital city of Managua and delayed the project, forcing the Government to decrease the amount of work to be done. A new agreement was reached and work was started in 1974 with renewed enthusiasm and expectations.

To develop the resource at Momotombo, several geophysical methods were used. Resistivity surveys with different technologies and configurations were carried out. Gravimetric and geochemical procedures were also utilized. Several field models have been proposed.

Drilling Exploratory and production drilling in the Momotombo Field is being accomplished with a National T-32 drilling rig capable of drilling to depths of 6,000 ft.

Producing wells in the Momotombo Field range have an average depth of 2,000 ft. with production rates in excess of 2,000,000 lbs mass flow per hr, averaging 700,000 lbs per hour. Thirty wells have been drilled, of which 20 are considered producers with an average cost of US $500.00 per meter.

Reservoir Analysis The primary objective of a reservoir assessment was to predict future reservoir life and performance. Flow rate tests and bottom-hole pressure measurements have been conducted. The purpose of these tests was to evaluate the hot water reservoir, to determine well interference effects, to determine reservoir boundary conditions, and to obtain mass flow rates and enthalpy.

These tests showed that

1. No detectable interference existed between some of the wells, and only very minor interaction occurred with a few.

2. Bottom-hole pressures recuperated rapidly during the first several minutes following shut in. As a general rule about 95 percent of its original pressure was recovered in the first ten minutes, returning to pre-production levels during the following several days.

3. The behavior of wells after completion of measurements and their rapid buildup indicates that the Momotombo reservoir is a large resource with essentially complete recharge.

Production rate is not a sensitive function of wellhead pressure at blowing pressures less than 150 psi. It has been concluded that in excess of 100 MW at the wellheads is now available to produce electric power on a long-term basis.

In a recent report prepared by the United Nations, it has been estimated that Nicaragua has a probable geothermal potential of 2,880 MW in high temperature fields and almost double that amount if medium temperature fields are included.

Environmental The effluent waters that amount to 80 percent of total flow present for the time being a problem to which a solution will have to be found. For the moment, several alternatives such as reinjection, and discharge into existing large bodies of water are being considered, and it is expected that a final decision that will meet the environmental requirements in harmony with our economic condition will be reached in the near future.

Generating Facilities The Government of Nicaragua has signed a load agreement contract with the Government of Japan for 7,500 million yen of soft capital toward installation of the first 35 MW unit at Momotombo. Completion is scheduled for late 1980 or early 1981. Bid documents are being prepared by American and Japanese technical consultants, and it is expected that a contract will be signed with the successful bidder before the end of this year.

The feasibility for the extension of the Momotombo power plant is about to be completed in order to introduce our application for additional financing.

Economic Impact The importance of geothermal energy for electricity generation in Nicaragua is obvious. A 100 MW geothermal plant will save about 25 million U.S. Dollars per year in fuel savings. With this economic promise, Nicaragua is basing much of its future on this kind of power generation.

Bio-mass I could not close my presentation without mentioning another promising project that is being studied at the moment and that has been referred to as Proyecto Caña Brava. This project considers the cultivation and direct burning of this plant for electricity generation. It grows fast, is sturdy, has a good calorific value, it grows in marginal land and most important, it is a natural, indigenous, renewable and economic resource; Caña Brava is from the same family as bamboo. Recent preliminary results have shown that it can be produced at a lower cost than the price of fuel oil and it would help to bring new job opportunities to the less developed areas of Nicaragua.

A Nicaraguan private industry is already proceeding with the installation of a dual-fuel generating unit that will use gas produced from Caña Brava.

As you can see, we are moving toward solutions to our energy problems; however, we need much effort, time, and help. We can supply the effort, but time is short, and we can use all the help we can muster.

Summary In summary, the oil crisis has forced Nicaragua to look at its own energy resources in depth and this has been good; we have found that we have abundant hydro and indications of abundant geothermal and bio-mass energy resources. The water resources can in addition be developed with our irrigable land resources to advance our agriculture exports. Industry, commerce, and tourism are additional viable activities that we can supply with our labor and energy resources. Development of this wealth of resources in a balanced program of economic expansion will provide a great challenge and opportunity to Nicaragua, an opportunity to considerably enhance the welfare of our people.

* Hon. Ing. Adán Cajina Ríos, Executive President, Empresa Nacional de Luz y Fuerza, represented the Government of Nicaragua as the luncheon speaker on June 22, 1978.