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NOTICE

Prepared by
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Santa Cruz, California

ABSTRACT

At the Fifth Annual Geothermal Conference and Workshop sponsored by the Electric Power Research Institute, special consideration was given the role of the demonstration power plant in utilizing geothermal resources for production of electricity. Attention was focused on current progress in developing demonstration plants, related research, and future planned activities, both in the U.S. and abroad. This Proceedings is a compilation of the formal presentations and the results of the associated workshop sessions.

The first geothermal conference was held in Kah-nee-ta in Oregon in July of 1977, with Proceedings published as EPRI Report ER-660-SR in January 1978. The second meeting was held in Taos, New Mexico, June 1978, with EPRI Report WS-78-97, October 1978, the result. A third meeting was sponsored in Monterey, California, in June 1979, Proceedings WS-79-166, issued in October 1979; and the fourth annual conference also in Monterey, June 1980, with Proceedings, EPRI TC-80-907, published in December 1980.

PREFACE

On the date of this conference the geothermal electric generating capacity in the United States was 931 MW(e). 488 MW(e) were under construction, 320 MW(e) were in the licensing stage, and 141 MW(e) were under design. This current activity involves 13 utilities, 10 geothermal fields, 4 conversion technologies, and 6 states. Most of this capacity will be at The Geysers; however, expansion into hydrothermal development is implicit in the numbers primarily in the form of hydrothermal demonstration projects. Beyond, 30 utilities are estimating around 10,000-MW(e) installed capacity by the year 2000. This future expansion will encompass 20 different geothermal fields in 11 states.

The longer-term expansion will be based primarily on hydrothermal resources and will be dependent to a large extent on the outcome of key demonstration projects now in various stages of completion. Since the term "demonstration" now seems to be in disfavor--possibly because of ambiguity about what demonstration projects are supposed to do, who should fund them, and when they are needed--for the purpose of this meeting, a demonstration has been defined as any project regardless of who funds it and whether or not it is designated as a demonstration if its primary objective is to make the crucial transition from "experimental" to "commercial" practice for some item of equipment or process. Prime examples include the Brawley project that is demonstrating scale control for hypersaline fluids, the Heber project that will demonstrate the resource utilization efficiency of binary-cycle technology, the Baca project that will demonstrate energy recovery from a complex reservoir, and there are others. Because of the critical nature of these projects and others that will follow, the role of demonstration projects was selected as the topic for workshop discussion at this year's meeting. The subject seems particularly timely in the present climate of tight money, federal budget cuts, and reordering of national priorities. Federal redirection away from demonstration projects is certain to have some impact on the growth rate since it is not likely that industry can pick up all of the near-term R&D pieces and transform them into commercially available technology. In any case, discussion of the issues in the workshop should contribute to a better understanding of the important issues and help in establishing industry priorities.

A second factor that makes discussion of the role of demonstration projects more timely is the increasing consideration of small wellhead generating units for each new geothermal field as a way to help assess the reservoir and to develop design criteria for larger power plants. This approach has considerable merit in view of slower-than-expected growth rate in hydrothermal capacity. It would seem prudent however to view wellhead units as a supplement to development rather than as a replacement for larger plants. The larger plants will still be needed during the same time frame, and work must continue if they are to be ready for commercial use.

EPRI's major thrust in its geothermal program continues to be on the development of hydrothermal resources with emphasis on moderate-temperature systems. The reports on the results of EPRI's R&D at this meeting are intended both to inform you about the work that is underway and to elicit your comments.

We sincerely appreciate the time and effort devoted by the international speakers who attended and participated in the meeting and feel that exchanges of information in this way will be helpful to all in their separate endeavors.

Finally, I want to acknowledge the superb cooperation and support of the utilities that helped with the meeting and to express particular appreciation to the Geothermal Program Committee for its help in chairing the many sessions.

Vasel Roberts, Project Manager
Advanced Power Systems Division

TABLE OF CONTENTS

SECTION 1 - OPENING

SECTION 2 - DEMONSTRATION POWER PLANT PROJECTS

SECTION 3 - PROJECTS AND PLANS OF ELECTRIC UTILITIES

SPECIAL REPORTS

SECTION 4 - EPRI GEOTHERMAL POWER SYSTEMS PROGRAM

SECTION 5 - RESULTS FROM EPRI PROJECTS

5A: ASSESSMENTS OF GEOTHERMAL POWER SYSTEMS

SECTION 8 - CLOSING

APPENDIXES

KEYNOTE ADDRESS

EPRI ANNUAL GEOTHERMAL MEETING

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When the Creator fashioned this earth, he decided, for some reason unknown to us, that there should be seemingly "free" heat energy available at some unusual and hidden locations; but he didn't provide that energy as free for the taking, as I intimated.

The hottest geothermal resource found to date has the greatest percentage of dissolved solids, and may turn out to be the most difficult to utilize. The vast majority of the geothermal resources found are really only warm, and may be unsuitable for use either by reason of remote location, or just plain too cold. And, when the best resource was found, that of direct steam from the mountains north of San Francisco, small concentrations of hydrogensulfide were also found just to test our ingenuity to solve problems. Someone else voiced what I have just said in a more succint manner when they said, "When it comes to using geothermal energy, Mother Nature seems to produce something that is highly objectionable or unpleasant."

Seriously, we at Utah Power & Light Company (Utah Power) are pleased to be associated with you who are working to find ways to utilize geothermal energy. We approach Utah Power's entry into this different alternative for us with some reservation, but look forward to working with you to generate economic kilowatt (kW) hours from Mother Nature's heat source.

For just a moment, I'll describe Utah Power for your information, then I'll talk about our activities in geothermal energy development, followed by a description of the unique features of our geothermal energy contract with Phillips Petroleum Company (Phillips). Then I'll conclude to allow time for you who are working to achieve technology breakthroughs to discuss your achievements.

Utah Power is an investor-owned energy utility serving Utah, southwestern Wyoming, and Southeastern Idaho.

Ninety-five percent of the electricity we sell comes from plants that burn coal.

We have one small generating unit that burns No. 6 oil or natural gas.

We have about 100,000 kW of hydroelectric generation, mostly located on the Bear River.

We also supply steam to some businesses in downtown Salt Lake City.

Our Company is growing both in areas served and electrical output.

We recently purchased the Lincoln Service Corporation, located just north of our southwestern Wyoming service territory. This acquisition added 6,000 square miles to our existing 80,000 square miles service area.

The Utah Public Service Commission has just granted us permission to purchase CP National's utility properties in southern Utah and northern Arizona. The Federal Energy Regulatory Commission must also approve this contract. If this acquisition is granted, it will add another 5,000 square miles of area to serve.

Our load growth has increased at an average annual rate of approximately nine percent per year for the past five years. Some recent single-year load rates have exceeded thirteen percent, and we expect our load growth to be nearly eight percent annually for the next five years.

Utah Power is a moderately large electric utility with assets of approximately $2 billion. To meet the anticipated demand for electric service, we will have to double the size of the Company in the next five years. You can see we're a growing Company, and you only have to look around to know that our area is one of the most exciting, fast-changing areas of the country. This works for and against us.

Although we are heavily involved in coal, and we own the vast majority of the coal we burn in central Utah, we recognize the need to broaden our energy alternatives. Therefore, we have chosen to develop renewable resources, such as geothermal, and to develop different ways of utilizing coal.

In this light, we are investigating a synthetic fuel process that would change coal into two other kinds of fuel - synthetic crude oil and char, a power plant fuel.

Roughly one ton of coal could produce one barrel of crude oil and a half ton of char.

We are excited about our future in geothermal energy. As many of you know, we executed a geothermal sales contract with Phillips in September of 1980. Then, in early December of that same year, our Public Service Commission approved the steam sale contract, and we were off and running. We issued a request for proposals to select an engineer for the project this past January, and then awarded the engineering contract to Gibbs & Hill in early March. In late January, applications for federal government approval were filed with United States Geological Survey and Bureau of Land Management.

The Phillips contract gives us rights to all of the geothermal resources found on federal lands leased to Phillips. We believe this to be about 75 percent of the total resource. We are currently negotiating with the ATO group, that is Amax Exploration, Incorporated, Thermal Power Company, and O'Brien Resources Corporation, to secure rights to the remainder of the resource - that located on state lands. There are just a few picky details for the lawyers to lay to rest, and then this contract should be ready for execution.

Engineering activities are proceeding for our first 20 megawatt (MW) project, which we call Milford Unit No. 1. If all permits and authorizations are received, we expect that Milford Unit No. 1 should be operational during 1984.

Milford No. 1 will be designed to be as simple as possible, to increase the probability that it will operate successfully. It will be a single-flash plant with four producing wells and three injectors. Only three producers will be required to produce full-power steam, and one injector will be used as a spare.

We are impressed with the extent and quality of the Roosevelt Hot Springs Reservoir, and we anticipate a successful project which would lead us to additional geothermal generating units.

We feel the full capacity of the Roosevelt Hot Springs Reservoir could reach 200 to 400 MW.

In addition to Milford No. 1, we are cooperating with EPRI in testing the second generation Biphase Rotary Separator Turbine Unit this fall at the Roosevelt Reservoir.

If we obtain all the permits necessary, we are hopeful that we can begin our tests in early September by generating into a load bank. Following completion of the transmission lines, we plan to generate into the Utah Power system one month later. This smaller, mobile rotary separator turbine unit will generate 1,600 to 2,000 kW initially and would be expandable to approximately 7,000 or 8,000 kW with the addition of a steam turbine unit.

The Company plans to study the economics of both the new wellhead unit and the more conventional 20,000 kW geothermal steam plant to determine whether it would be better to build pipes to carry the steam to the larger, central plants, or transmission lines from the individual small units to an electrical substation, or develop a system using both plants and the small units.

We appreciate EPRI's leadership in developing geothermal conversion devices such as the Rotary Separator Turbine Unit that offer greater efficiency and flexibility of utilizing geothermal fluids.

There are some unique features of the Phillips and ATO steam sales agreements. Both of these agreements dedicate the resource to Utah Power for electric power generation.

The primary term of the agreement is for 35 years after construction of the last generating unit, but not longer than 50 years after execution.

Steam is sold on a price-per-pound basis multiplied by a capacity adjustment factor, and the number of pounds of steam utilized. If the previous 12-months average capacity factor is 70 percent, then the capacity adjustment factor is equal to one. The factor is less than one for capacity factors greater than 70 percent, and greater than one for poor load or capacity factors. The factor does not operate to our detriment if Phillips or ATO cannot deliver steam when we can operate.

We also pay a price per pound of water multiplied by the number of pounds of water delivered to Phillips for injection. The capacity adjustment factor is not included in the injection cost calculation.

The contract steam and water injection prices are stated on a block basis. That is, there is a more expensive price for the first unit, a less expensive price for the second unit, and a lower price for the third and all subsequent units.

A portion of the steam and water price is not allowed to escalate, and the greater portion of the price is allowed to escalate, based on published government indices.

One other unusual feature of the contract is that Utah Power will construct and operate the steam gathering and water injection systems for Milford No. 1, and all future generating plants. Phillips, as the unit operator, will drill and operate all production and injection wells and the wellhead separator unit. Phillips will also meter the steam and water flows.

The contract was an attempt to provide the producers with a reasonable return on their investment while both parties work together to produce the lowest possible cost of electric energy produced.

In conclusion, we at Utah Power compliment EPRI's lead to develop technology and data for the electric utilities' use in their efforts to generate electric energy from geothermal energy. We plan to utilize many of the EPRI tools, such as the mobile geothermal laboratory and brine chemistry computer program, to enhance the probability that Milford No. 1 will operate successfully.

With the thousand plus megawatts installed at the Geysers, and additional megawatts planned by many different developers and utilities in that same area; with numerous flash steam or binary units either operating, planned, or under construction in the Imperial Valley; with exploration and testing being conducted in Nevada; with development activities being conducted in New Mexico; with planned development of 20 megawatts at southwestern Utah; with geopressure exploration increasing in the gulf states; with all of this activity, I see strong evidence that electric generation using geothermal energy will take a major position with the western utilities in the near future. We utilities need this renewable resource to help meet our load growth requirements.

We applaud you who are here and working together to develop solutions to geothermal problems. This workshop is an important step in disseminating information that will be helpful to all engaged in geothermal energy utilization. We look forward to large-scale development of geothermal resources to provide another alternative for electric energy generation.

HEBER GEOTHERMAL BINARY DEMONSTRATION POWER PLANT

NEW DEVELOPMENTS

RP 1900-1

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Background SDG&E has been associated with geothermal exploration and development in the Imperial Valley since 1971. SDG&E currently has interests in the four geothermal reservoirs shown in Figure 1.

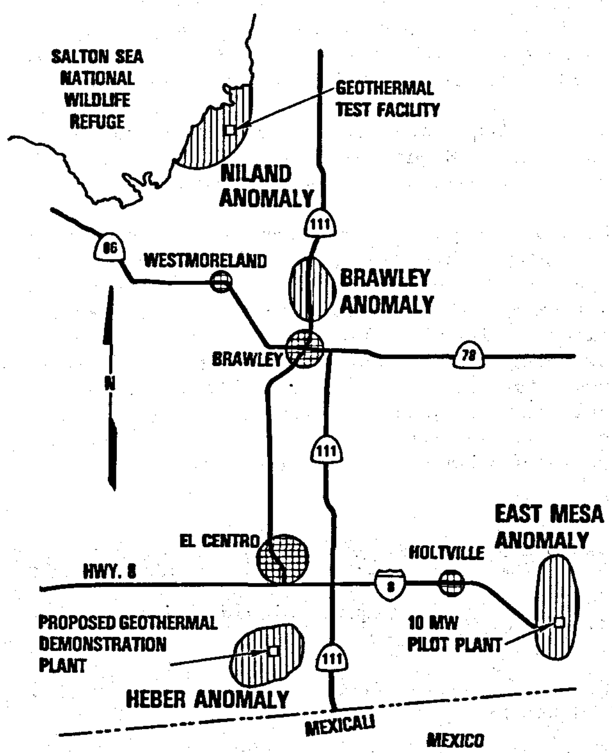

FIGURE 1
IMPERIAL VALLEY GEOTHERMAL RESERVOIRS
LOCATION MAP

Major SDG&E activities (or activities of its subsidiary, New Albion Resources Co. [NARCO]) have included drilling and flow testing geothermal exploration wells, feasibility and process flow studies, small scale field testing of power processes and equipment, and pilot plant test facility design, construction, and operation. Supporting activities have included geothermal leasing, acquisition of land and water rights, pursual of a major new transmission line to carry Imperial Valley geothermal and other electric power to San Diego, and support of Magma Electric's 10 Mw East Mesa Geothermal Power Plant. Current SDG&E efforts emphasize commercial scale planning, risk reduction, and reservoir development.

EPRI-sponsored work leading to this Project has been heavily relied upon. Field testing, environmental baseline, and feasibility studies were used as a point of design departure for Heber Binary Project design, development, and optimization. In 1975, EPRI commissioned The Ben Holt Company and Procon, Inc., to perform a study (EPRI Research Project 580) on the feasibility of constructing and operating a geothermal demonstration power plant utilizing low-salinity, liquid-dominated hydrothermal resources. The study originally considered 16 reservoirs in the Western United States, but narrowed the choice for detailed analyses to 3 potential sites. Briefly, the study concluded that the Heber geothermal reservoir in Southern California's Imperial Valley was the best location for the demonstration plant, that the binary cycle would produce power at a lower cost than the two other thermodynamic cycles evaluated for that site, and that a demonstration plant producing approximately 50 Mw should be constructed to demonstrate the commercial potential of power produced from liquid-dominated geothermal resources in the United States. The Heber Binary Project is based on the result of the feasibility study.

SDG&E conducted heat exchanger tests at the Heber reservoir for EPRI beginning in 1974, which showed minimal problems in handling the Heber brine. After the EPRI feasibility study selected the Heber reservoir as the best site for the demonstration plant, SDG&E began conducting an environmental baseline data acquisition study to gather baseline environmental information at the reservoir and to assess the potential impacts of geothermal development.

SDG&E has been planning a commercial-sized geothermal demonstration plant for a considerable length of time. An option for SDG&E or the Federal government to fund a 50 Mw demonstration power plant was included in a 1975 contract for the Niland Geothermal Loop Experimental Facility.

To expedite the development of the binary cycle plant, in August 1979 the Congressional managers of an appropriations bill directed DOE to proceed without further delay with the development of a 50 Mw binary cycle conversion geothermal demonstration plant...[and] to select a site for this demonstration plant within three months." (Energy and Water Development Appropriation Bill, 1980, Conference Report No. 96-388, 96th Congress, 1st Session, p. 22.) DOE was thus required by Congress to select a plant site and to begin negotiations for the construction and operation of a binary cycle plant. SDG&E consulted with other utilities and interested parties and decided to solicit government funding for a binary plant at Heber.

SDG&E obtained expressions of interest from other utilities to participate in the Heber Binary Project. The Imperial Irrigation District, Southern California Edison Company, and the California Department of Water Resources all expressed an interest in sharing in the construction and operation costs of the Project. In addition, EPRI also indicated that it would again consider a proposal to contribute funds to a binary cycle demonstration plant at Heber on behalf of the United States electric utility industry.

In December 1979, SDG&E submitted an unsolicited proposal to DOE and EPRI to obtain financial assistance for the design, construction, and operation of a commercial-size nominal 50 Mw binary cycle demonstration plant. In conjunction with this proposal, SDG&E requested and was granted special rate treatment for its Project costs by the California Public Utilities Commission in January 1980. R&D funds will be used by SDG&E to support this Project.

DOE selected Heber as the site for binary cycle demonstration in January 1980. In March 1980, DOE accepted SDG&E's proposal as a basis for negotation for a Cooperative Agreement. Negotiations with DOE were initiated on March 27, 1980, and a Cooperative Agreement was executed on September 27, 1980.

The EPRI Geothermal Program Committee approved the Project in January 1980. Their Renewable Energy Systems Task Force approved the Project in February 1980, and the Advanced Power Systems Divisional Committee also approved the Project during March 1980. Final EPRI Board of Directors approval of the Project occurred in May 1980. A participation agreement with EPRI was executed by SDG&E on October 3, 1980, and by EPRI on October 21, 1980.

Negotiations with the other utilities commenced in March 1980, and led to a Participation Agreement that was executed by all Parties in early December 1980.

Project Description The objectives of the Heber Binary Project are (1) to demonstrate the potential of moderate-temperature geothermal energy to produce economic electric power with binary cycle conversion technology; (2) to allow the scaling-up and evaluation of the performance of binary cycle technology in geothermal service; (3) to establish schedule, cost and equipment performance, reservoir performance, and the environmental acceptability of such plants; and (4) to resolve uncertainties associated with the reservoir performance, plant operation, and economics.

The Project will be the first large-scale power generating facility in the U. S. utilizing the binary conversion process. It is expected that information resulting from this demonstration plant will be applicable to a wide range of moderate-temperature, low-salinity hydrothermal reservoirs. Eighty percent of U. S. geothermal reservoirs fall into this category.

The binary cycle energy conversion process to be employed has the major advantage of being capable of converting a greater amount of geothermal heat from moderate-temperature brines into electric power. Heber beginning-of-life and end-of-life conditions, shown in Table 1, indicate that the binary cycle may be capable of utilizing significantly less geothermal fluid per net kilowatt generated than the dual flash cycle.

	BINARY CYCLE		DUAL FLASH CYCLE	
DESCRIPTION	BOL	EOL	BOL	EOL
Brine Supply Mode	Liquid Phase	Liquid Phase	Two Phase	Two Phase
Brine Flow Rate MM Lbs/Hr	7.14	8.88	9.8	12.7
Brine Supply Temp Degrees F	360	338	293	293
Brine Return Temp Degrees F	160	160	215	215
Net Cycle Eff Percent	11.2	11.0	11.6	10.7
C.W. Flow Rate GPM	129,500	134,300	145,900	161,500

TABLE 1
COMPARATIVE PERFORMANCE
(BINARY VERSUS DUAL FLASH)

As geothermal power plants become larger (to take advantage of economies of scale) and available high-temperature resources become fully developed, the predominant cost associated with producing geothermal power will be related to brine supply and disposal. These costs can be significantly reduced for the binary plant. Binary cycle technology will also increase the total potential output of each geothermal resource.

However, to realize all of these potential benefits, commercial-size binary cycle technology must be demonstrated. Commercial reliability, safety, and costs must be established. Much of the technology is now in existence and being proven in geothermal pilot plants and other applications. However, this technology has not been demonstrated on a commercial scale. The major plant components, such as the hydrocarbon turbine, have not been constructed in this size.

Power Cycle Description The power cycle consists of a geothermal brine loop and a hydrocarbon binary loop as shown on Figure 2. The geothermal brine is delivered to the power plant under liquid phase (nonflashing) conditions from pumped wells at a temperature of approximately 360°F and a pressure of 200 psig. Temperatures are expected to decline with time as the reservoir is developed. The brine loop contains a bank of eight shell and tube heat exchangers arranged in a series parallel configuration. The thermally spent brine is returned for injection to the geothermal reservoir at a minimum temperature of 150°F.

The binary loop contains the hydrocarbon working fluid and provides for the transfer of geothermal energy from the brine to the hydrocarbon turbine. The hydrocarbon is pressurized and heated under supercritical conditions before entering the turbine throttle at 575 psig and 305°F. The working fluid is expected to be a mixture of 90 mole percent isobutane and 10 mole percent isopentane.

The power cycle control system is designed for base load turbine generator operation with limited load variations associated with daily and seasonal temperature changes and electrical system demand. The controls are capable of maintaining system frequency during periods when the plant output represents a major part of the power reserves on the grid.

The Project will incorporate a floating cooling cycle instead of the originally planned fixed cooling cycle. A floating cooling cycle permits the optimization of yearly power output by taking advantage of variations in wet bulb temperatures. The application of this concept to a geothermal binary cycle power plant was first investigated by Lawrence Berkeley Laboratory. The turbine back pressure, and therefore the condensing temperature, is adjusted to generate the maximum available power provided by the variable wet bulb temperature. In contrast, a fixed cooling cycle operates at a constant condensing temperature and delivers constant power during the time that the design wet bulb temperature is not exceeded. By incorporating the floating cooling concept, the plant average efficiency

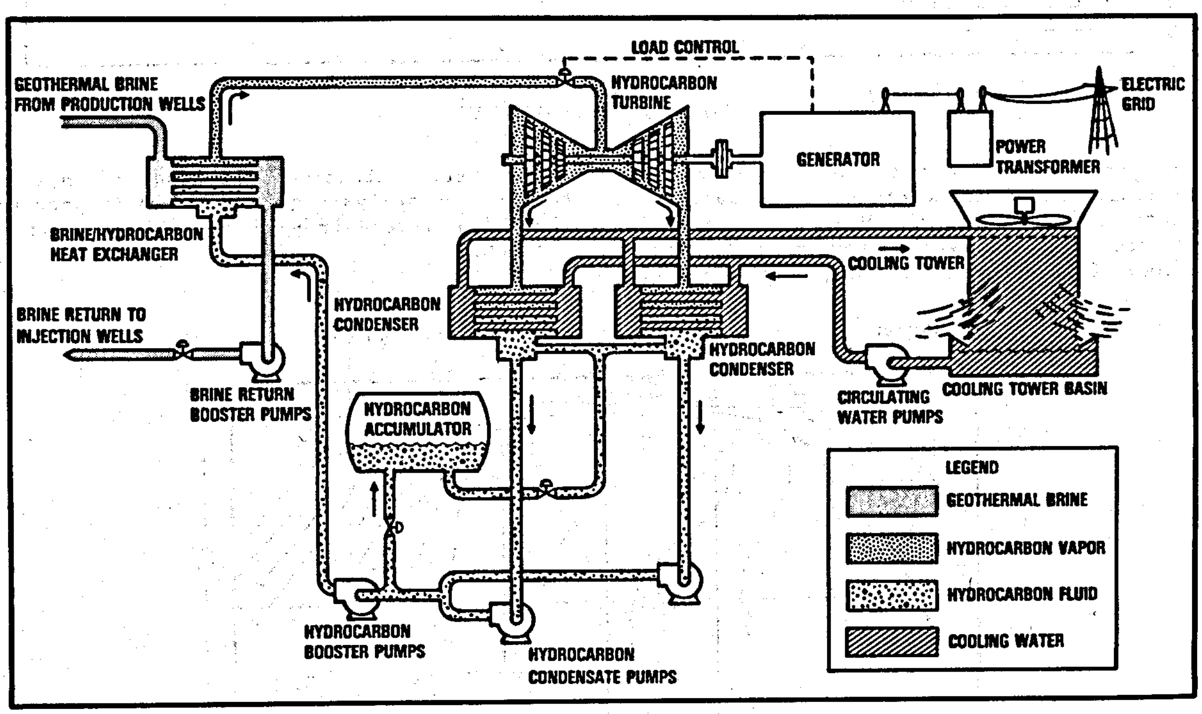

FIGURE 2
POWER CYCLE

is improved (with a corresponding reduction in brine requirements) while maintaining an average net power output of 45 Mw.

The power plant will be an outdoor-type station. The outdoor concept provides for the turbine generator and other major equipment to be installed outside to reduce capital cost and minimize safety hazards associated with the handling and containment of the hydrocarbon working fluid.

The plant site contains both the power plant and brine production facilities. The brine reinjection wells are located about 2.5 miles northwest of the plant site. The power plant plot plan is shown on Figure 3. The combined power plant/production island requires just under 20 acres.

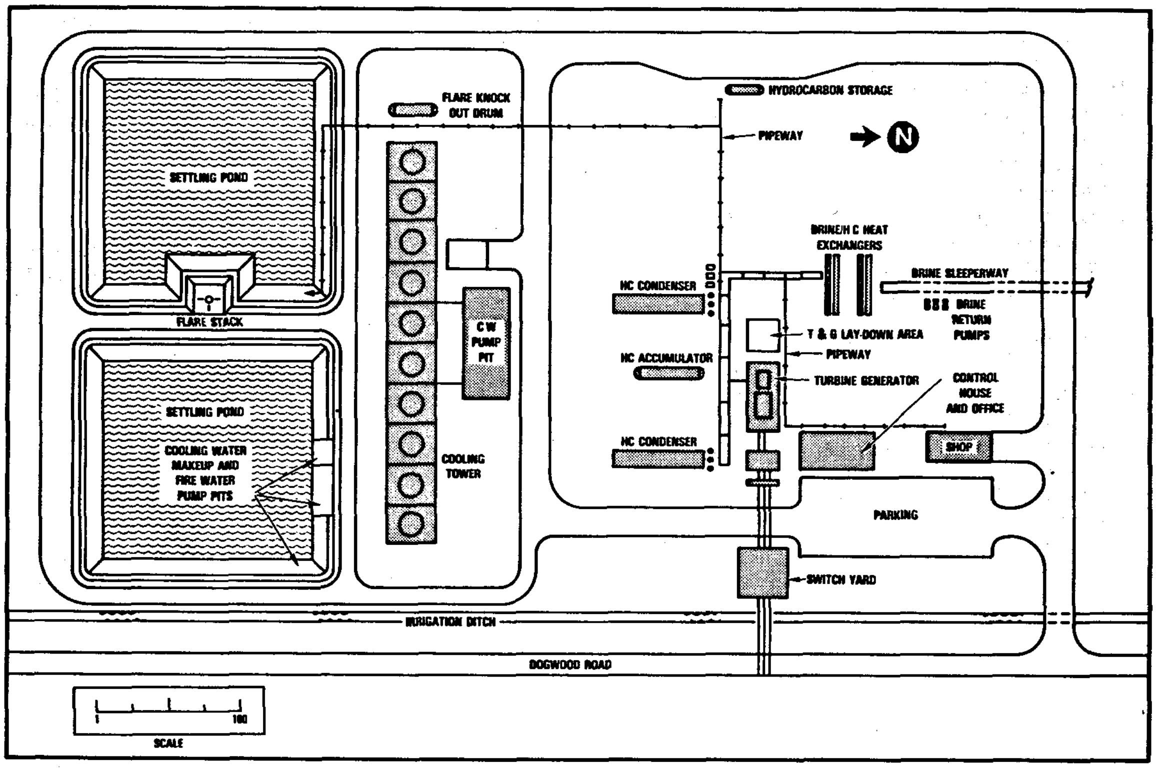

FIGURE 3
POWER PLANT PLOT PLAN

The Project is expected to be in service in early 1985. SDG&E is negotiating for purchase of geothermal heat for the Project. Figure 4 shows some of the wells and includes the reservoir temperature profile to a depth of 6,000 feet. Extensive well flow and injection testing and analysis gives high confidence that the Heber reservoir will reliably support the Project.

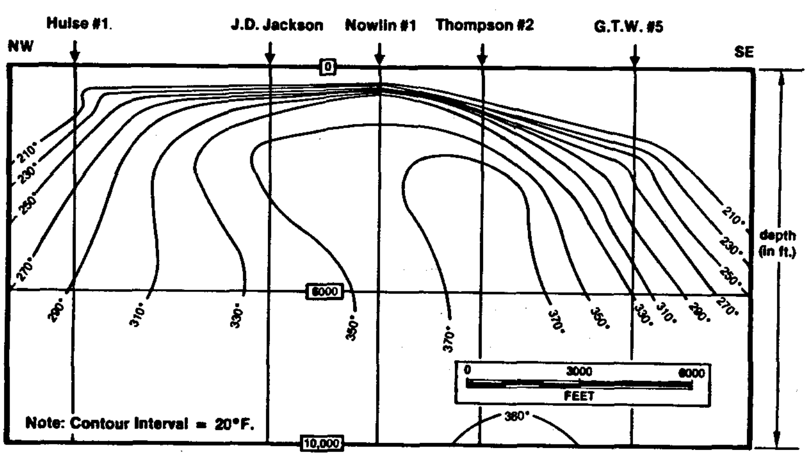

FIGURE 4
NW-SE TEMPERATURE CROSS-SECTION OF THE UNIT AREA

Current Activities Current Project activities are focused on the engineering effort which started January 1, 1981.

A geotechnical services contract with Fugro, Inc. (now Ertec) was executed in November 1980. Fugro's work covered two areas: a soils investigation to determine the load-bearing capability of the soil and a study to update the seismic design criteria developed for the former Heber Project using data from the October 1979 earthquake. Fugro completed field exploration for the Project, including cone penetration tests, drilled borings, installation of piezometers, downhole geophysical tests, etc., in November and December 1980. Data interpretation and engineering began in December 1980. A final report was issued in May 1981.

A contract with Pickard, Lowe and Garrick (PL&G) for the Availability Enhancement Program, which will assess and improve the availability of the power plant, was executed on March 26, 1981, and the work is in progress. PL&G issued a preliminary Availability Data Book containing analyses of the Heber Binary Plant based on the EPRI ER-1099 report. PL&G will update this Data Book to reflect the design as it progresses and will incorporate work being done by ARINC Research Corporation, under contract to EPRI. Preliminary studies to evaluate the impact on availability and rate of return of alternate substation, brine hydrocarbon heat exchange, and condenser configurations have been completed.

An agreement with Fluor Power Services (FPS) for engineering and procurement services was executed on December 29, 1980. An engineering kickoff meeting was held on January 13, 1981, to outline the initial goals and a tentative front-end schedule was developed for the Project.

The Design Guide was finalized and distributed prior to the Conceptual Design Review meeting held on April 1, 1981. The Design Guide provides the documentation of overall plant objectives, operating philosophy, preliminary design descriptions, design objectives, and criteria. A physical description of the entire facility is included. The Design Guide ensures that all Project participants will utilize the same general basis for engineering and design activities.

Criteria relating to the following categories are provided:

SDG&E Design Philosophy and Objectives
Site Information and Criteria
Civil/Structural/Architectural Design
Mechanical Design
Electrical Design
Process Design
Instrumentation and Control Design

The descriptions in the Design Guide are based primarily on the preliminary baseline design and optimization studies in Electric Power Research Institute (EPRI) Final Report, EPRI ER-1099, dated June 1979. Most of the major process design parameters were confirmed for incorporation into the Project Design Guide. These included the binary working fluid composition, brine reservoir, start-of-run and end-of-run temperatures, brine supply pressure, brine return temperature, hydrocarbon turbine throttle conditions, power generator capacity and cooling water temperatures. The major change was an increase in the brine return pressure. It was also verified that the Benedict-Webb-Rubin (BWR) equation of state for a supercritical Rankine Cycle will be used to determine sizing parameters for the binary working fluid system. Significant or major changes to this baseline information will be incorporated as the design progresses.

We are performing an evaluation of Distributed Digital Control (DDC) technology for use at Heber in lieu of an analog control system. DDC has the potential to provide more flexible control capability with lower maintenance costs and higher reliability; it would also permit easy access to plant records for data retrieval and dissemination.

The first Sponsors' Management Committee meeting was held on December 17, 1980. The Committee approved the Project schedule, goals, objectives, and budget for the Phase I effort. The second meeting was held on April 22, 1981. The Project schedule is shown on Figure 5.

The first meeting of the Sponsors' Technical Committee was held on April 2, 1981. The Committee reviewed preliminary results of the floating cooling evaluation and approved proceeding with this concept.

The bid specification for the hydrocarbon turbine generator is being prepared. We plan to make an award in September 1981.

The data management contractor will acquire, analyze, and disseminate Project data to a wide audience for the purpose of stimulating commercial development of hydrothermal resources in the United States. Selection of a consultant is in abeyance due to the uncertainity of continued federal funding. Significant progress has been made, however, in drafting the Scope of Work document, selecting bidders, preparing evaluation criteria, and preparing the Invitiation to Bid document.

Project Philosophy Demonstrating the commercial scale reliability and economics of the binary cycle process is the primary consideration for the Project. This has resulted in a "simple and strong" approach to the power plant design. Use of only a single hydrocarbon loop and fresh water cooling are examples of this approach.

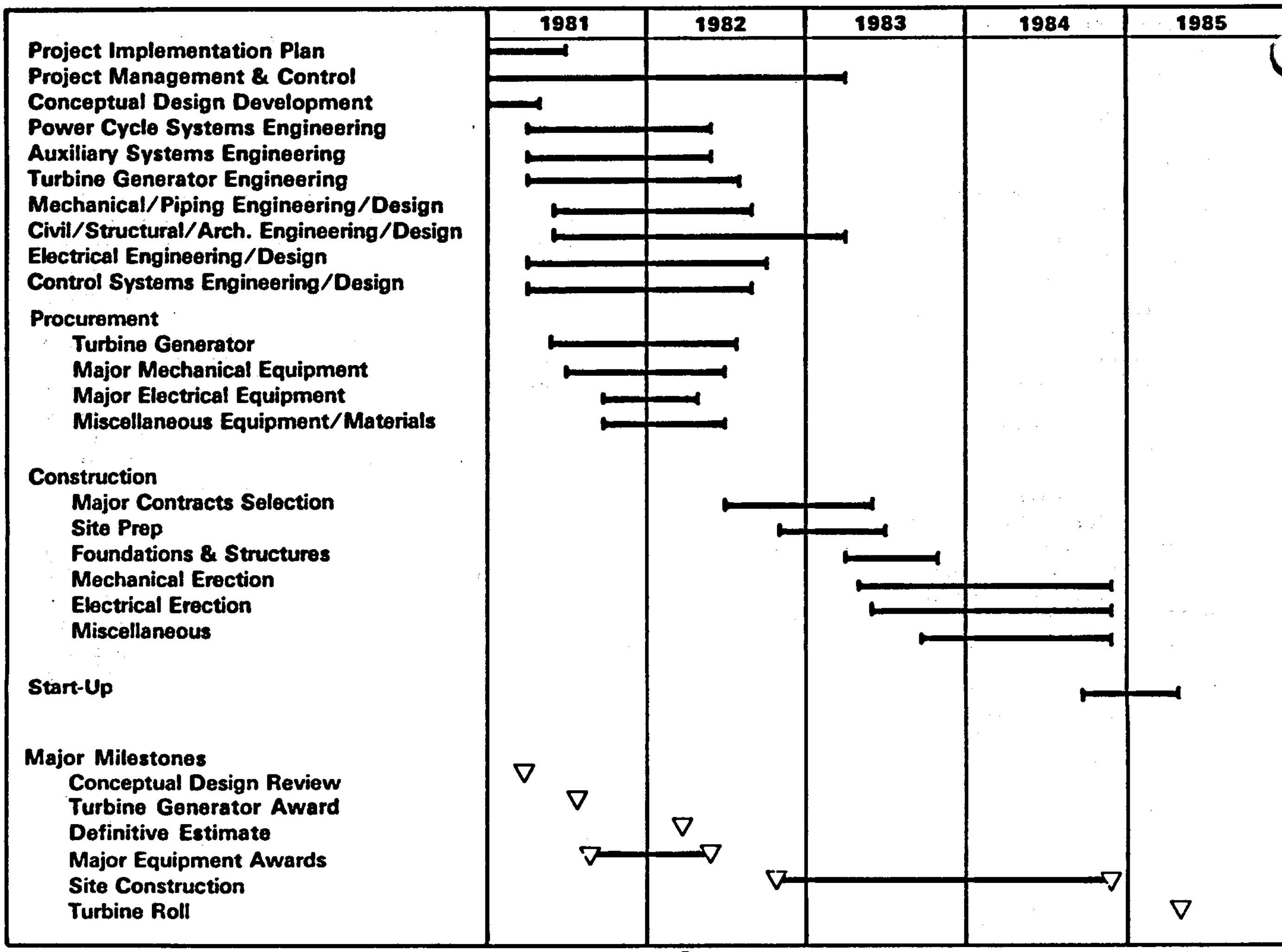

FIGURE 5
MASTER SCHEDULE

Proven, off-the-shelf hardware will be used wherever possible. Geothermal binary pilot plant and petrochemical industry experience will be carefully reviewed. Provisions for future modifications, replacement, or upgrading will be considered, but will not be allowed to compromise this philosophy.

Strong reliability, safety, and quality control efforts are being implemented. These efforts will extend throughout the several phases of the Project. SDG&E believes that economic impact of poor plant reliability and availability justifies a significant effort in these areas.

<u>Summary</u> SDG&E has commenced the design of a binary cycle demonstration plant. The Project is being supported by DOE, EPRI, four public and private utilities, as well as the California Public Utilities Commission. The Project is expected to confirm the technical and economic superiority of the binary cycle process at a representative moderate-temperature geothermal resource, stimulating nationwide geothermal development of these currently unused resources.

BACA 50 MWe DIRECT FLASH DEMONSTRATION POWER PLANT

Jack D. Maddox
Public Service Company of New Mexico
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Albuquerque, New Mexico, 87158 (505) 848-4870

The Baca Geothermal Demonstration Project includes an integrated commercial scale geothermal electric power generating plant which will utilize a liquid-dominated resource. As such, it includes the geothermal field system, fluid production equipment, fluid transmission system, steam separator system, electric generating plant, geothermal fluid treatment and spent fluid disposal facilities, and a tie-in to the electric utility transmission networks.

Union Geothermal Company of New Mexico (Union) is responsible for exploring and developing the geothermal resource within the area of Baca Location No. 1, located in Redondo Canyon of Rio Arriba and Sandoval Counties, New Mexico, as outlined in Figure 1.

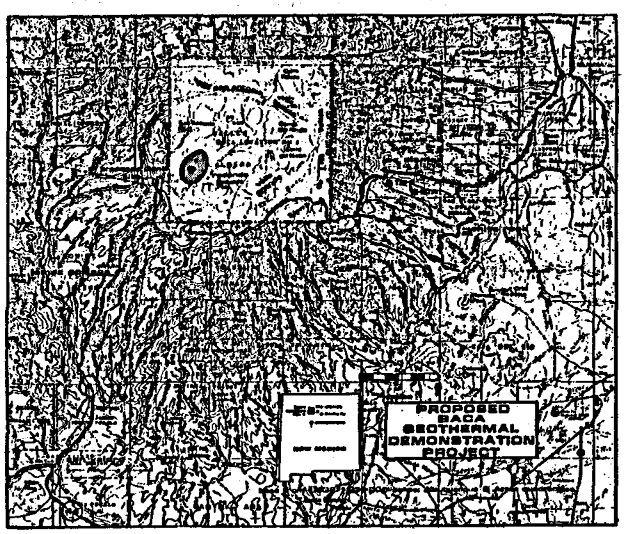

Figure 1

Further, Union will construct and operate all field facilities on the Project site, including all wells, pipelines, and effluent disposal equipment necessary to deliver geothermal energy to PNM. PNM will construct and operate an electrical generating unit of approximately 50 gross MW capacity and all necessary air pollution control equipment located in the center of Redondo Canyon. PNM will also construct and operate the transmission facilities to interconnect the generating unit to PNM's existing transmission system.

A Cooperative Agreement was executed in 1978 with the Department of Energy (DOE).

Pursuant to this Agreement, PNM and Union are to act collectively as Participant and are to design, construct, and operate the Geothermal Demonstration Power Plant Project (Project) with scheduled commencement of commercial generation in 1982.

The objectives of the Project, in support of the DOE's overall goal to stimulate development of geothermal energy, are as follows:

A. Demonstrate reservoir performance characteristics of a specific liquid-dominated hydrothermal reservoir.

B. Demonstrate the validity of reservoir engineering estimates of reservoir productivity (capability and longevity).

C. Demonstrate a conversion system technology at commercial scale.

D. Initiate development of a resource of large potential.

E. Act as a "pathfinder" for the regulatory process and other legal and institutional aspects of geothermal development.

F. Provide a basis for the financial community to estimate the risks and benefits associated with geothermal investments.

G. Demonstrate social and economic acceptability and the readiness of state-of-the-art technology for producing electric power from a liquid-dominated hydrothermal resource.

The power plant site is located in moderately rugged terrain at an elevation of 8,730 feet above sea level. This location presented some unique and challenging design problems which were resolved through detailed scheduling of critical construction activities around the inclement weather periods and optimally arranging the major plant components considering:

- The available level ground space.

- Wind direction with respect to cooling tower location.

- Best relative location of the power block, cooling tower, switchyard, and H_2S abatement systems with respect to each other and steam line entry and transmission line egress points.

Bechtel Power Corporation (Bechtel) was contracted to do the A/E and construction management services. Using the above location and constraints and, of course, the geothermal steam properties and corrosion data that had been collected for these geothermal fluids, Bechtel has essentially completed the design work. The details of the bulk of the design efforts were presented at last year's EPRI conference by Mr. John Bouma, entitled "Shaping A Geothermal Power Plant." I will therefore just give a brief overview of the power plant design and some of the unique design features incorporated into the final design.

A total of twelve design studies were conducted; some at the specific request of PNM and others strictly through Bechtel's initiative. These studies encompassed:

1. Circulating water pump and condenser optimization.

2. Surface condenser design to maximize H_2S removal and minimize CO_2 blanketing.

3. Clean room design to minimize H_2S corrosion.

4. Use of fiberglass reinforced pipe and tanks.

5. Plant water and chemical balance to minimize make-up water requirements.

6. Turbine blow-off piping to enhance safety and minimize plant H_2S levels.

7. Plant materials selection.

8. Special control room and maintenance facilities for remote site location.

9. Alternative non-condensible gas removal optimization.

10. Plant color selection.

11. Effect of altitude on electrical components.

12. Optimization of cooling tower design.

Again, I would refer you to the detailed report of Bechtel's presented at last year's conference for any details.

Licensing and permitting activities have consumed a considerable amount of time and effort on this Project. The overall schedule was impacted by difficulties in the DOE's release of the final EIS and a requirement of a Record of Decision. These requirements delayed the scheduled start of power plant construction by approximately one year. Licensing activities required for construction of the power plant in New Mexico further delayed power plant construction start.

THE BACA GEOTHERMAL PROJECT: LEGAL AND REGULATORY CHALLENGES

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The Baca Geothermal Demonstration Power Plant (GDPP) Project is organized and cost-shared under a cooperative agreement between the U.S. Department of Energy, Public Service Company of New Mexico (PNM) and Union Geothermal Company of New Mexico. The agreement is the result of an effort begun in 1977, when DOE distributed a Program Opportunity Notice (PON) to solicit offers from private industry to participate in a geothermal demonstration power plant project. DOE accepted the proposal submitted by Union/PNM for development of liquid-dominated fractured volcanic reservoirs by employing the flash steam process.

The overall objective of the GDPP Project is to stimulate commercial development of hydrothermal (liquid-dominated geothermal) resources in the United States. DOE's rationale for backing the project is to provide data obtained from actual operation of a commercial-scale facility to encourage industry to pursue hydrothermal options. WESTEC Services was selected to collect and reduce the data to report form for distribution to the geothermal public.

A portion of the data management effort (now delayed due to additional work needed in the area of resource confirmation and evaluation) focused on the regulatory and legal challenges facing the project participants. The following discussion will center on three topics in the legal and regulatory area:

1. The Baca Cooperative Agreement

2. The Permitting Process

3. Record of Decision

1. The Baca Cooperative Agreement

Union and PNM began discussions on jointly developing geothermal resources located in Redondo Canyon at Baca Location Number One, New Mexico in 1974. Union's role was to produce steam for sale to PNM. PNM would, in turn, produce electricity from the steam at a power plant which PNM would constuct, and would commercially distribute the electricity. By 1977 discussions between the two centered on jointly developing a 50 MW plant.

DOE, Union and PNM began negotiations in September 1978 to develop a cooperative agreement. DOE must choose the cooperative agreement as the award instrument if the agency anticipates substantial involvement between itself and the recipient throughout the course of a project in which it is participating to accomplish a public purpose of support or stimulation (Public Law No. 95-224). Utilization of a cooperative agreement is intended to provide a more flexible mechanism than a procurement contract for achieving these goals. A description of the Baca Agreement follows.

In the Agreement, Union and PNM are characterized as separate entities, which comprise a single entity called Participant. The Agreement specifies, however, that the failure of either Union or PNM to perform will be deemed failure of performance by both. The contractual period of performance is from July 14, 1978 through completion of the Operational Phase of the project (approximately March 1, 1987) or termination of the Agreement pursuant to the "Termination/Election to Continue" provision. Subject to the termination provisions, the Revenue-Sharing provision (see below) remains in effect after completion of the Operational Phase.

The total estimated cost of performing the work under the Agreement is $133,674,989 which is divided among three project elements:

1. Wells and Steam Production

2. Power Plant and Distribution System

3. Data Gathering, Evaluation and Dissemination

DOE will fund a maximum of $24,480,000 toward Element 1; $24,480,000 for Element 2; and all costs for work performed under Element 3, subject to modification. In addition, for $7,415,500, DOE purchased a 50 percent interest in Union's costs of developing data on the Redondo Creek area from 1971 to 1977. The ratio of DOE's share of the overall cost of the project to that of Participant is 49:51.

Participant's estimate of costs and schedule of performance was based on expected completion of the Environmental Impact Statement (EIS) process by August 6, 1979. In the event of a significant delay causing an increase in project costs, the parties agreed to negotiate in good faith to adjust equitably the parties' contributions. Such delays already have resulted in several modifications to the contract.

In the important area of revenue-sharing, Union is obligated to reimburse DOE for a portion of the project costs based on a specified formula if all of the following events occur:

a. Participant operates the project facilities on a commercial basis for 12 months following the 5 year Operational Phase of the project.

b. The Agreement remains in full force and DOE participates in the project at least until the Operational Phase commences.

c. At the time payments are to begin, federal income tax law entitles Union to deduct a depletion allowance corresponding to a percentage of new revenues received by Union from PNM for geothermal steam delivered. Provision is made for payments at three month intervals. The amount of each payment by Union to DOE will equal 50 percent of Union's tax savings resulting from the depletion allowance deduction.

The Revenue-Sharing provision contains these limitations:

a. The maximum percentage recoverable by DOE is 50 percent of its "aggregate project costs."

b. The percentage of costs for which Union must reimburse DOE is reduced in the event Union or PNM's aggregate Project costs exceed specified amounts.

2. The Permitting Process

As with any proposed geothermal project, the proponents must deal with various regulatory requirements. For the GDPP Project, both the resource developer (Union Geothermal) and the resource utilizer (PNM) applied for permits mandated by state and federal agencies.

For Union, the most critical permitting constraint to supplying steam has been securing approval of the State Engineer's Office to appropriate underground waters and to change the point of diversion and place and purpose of use for surface waters. The State Engineer granted the requested permits subject to several conditions. However, one of the Indian Pueblos involved in the administrative hearings filed an appeal in the New Mexico District Court. The appeal was scheduled for trial in June 1981. On May 18, 1981, the District Court postponed hearings of this case until January 1982.

On the utility side, PNM has secured the majority of its permits and clearances. It has not obtained a Certificate of Public Convenience and Necessity, a prerequisite to construction and operation of any new generating facility. The New Mexico Public Service Commission (PSC), which has jurisdiction over state public utility matters, held extensive hearings on this application throughout the summer and fall of 1980. Environmental, Indian, and consumer groups oppose construction of the plant at the Baca site on such diverse grounds as socio-economic impacts on the region, infringement of Indian religious practices and the absence of a present need for the additional 50 MW capacity. In May 1981, the PSC issued an order indicating it will hold PNM's application in abeyance because of the utility's decision to reevaluate the project.

2. The Record of Decision

Under federal NEPA and CEQ regulations, the environmental process is triggered any time the federal government involves itself in a proposed activity which is considered a significant federal action. Since the GDPP project was an action expected to result in the construction and operation of a full-scale energy system project, preparation of an EIS was required. CEQ regulations also mandate publication of a Record of Decision which is a public record explaining the basis for an agency's choice of a particular course of action within the EIS process.

Who within the agency has the responsibility for issuing the EIS and Record? DOE guidelines and the precedent set by the Baca EIS and Record of Decision indicate that the program office, i.e., the Division of Geothermal Energy (DGE) and the Assistant Secretary of Resource Applications, are responsible for environmental decision-making in projects of this nature.

DGE's role is supported within DOE by the NEPA Affairs Division, Office of the Assistant Secretary of the Environment. The NEPA Affairs Division reviews the document prepared by DGE and, if appropriate, makes recommendations for change. Therefore, while the Assistant Secretary of Resource Applications issues the Record of Decision, the Secretary of the Environment must concur before its publication. (Because of the project's direct impact on Indian Pueblos, the Office of the Director -- Intergovernmental Affairs, Office of the Secretary of Energy, acted as an advisor on issues of infringement of Indian rights and was a signatory to the Record of Decision.)

DOE issued a Record of Decision on May 5, 1980 indicating it would continue participating in the Baca project. The Record of Decision cited these advantages of supporting the Baca project: system design, prime geothermal resource, capability of DOE partners, and cost sharing between the partners and the Government. DOE balanced these expected benefits against potential environmental concerns notably the possible degradation of air quality, depletion of surface and groundwater supplies, and infringement of American Indian religious freedom. DOE concluded that these advantages, as well as the feasibility of mitigating the environmental impacts of the project, favored development at the Baca site.

BACA RESERVOIR DATA ANALYSIS AND DISSEMINATION: STATUS AS OF JUNE 1981

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Introduction Systems, Science and Software (S^3), acting as a subcontractor to WESTEC Services, Inc., was responsible for the geological, geophysical and reservoir engineering aspects of the Baca Data Gathering, Evaluation and Dissemination contract from February 1980 to June 1981. This paper briefly describes the contents of the five detailed technical reports completed by S^3 during this period, including the conceptual model that has evolved for the Baca reservoir in the Redondo Creek area.

Pressure Transient Analysis Since the transient pressure data available from the various Baca wells indicate in-formation flashing during drawdown and no analytical techniques exist for interpreting buildup data for two-phase reservoirs, the S^3 geothermal reservoir simulator CHARGR was employed in a series of calculations to deduce the general features of drawdown/buildup response in geothermal wells. The numerical results form a theoretical framework for interpreting the flow data from the production/injection wells at Baca or other two-phase systems. Specifically, CHARGR was used to simulate a series of well tests to investigate (1) the drawdown/buildup response of hot water wells, (2) the drawdown/buildup behavior of initially two-phase reservoirs, (3) the drawdown/buildup response of initially single-phase reservoirs which undergo flashing as a result of fluid production and (4) the effect of fluid injection into single-phase and two-phase reservoirs.

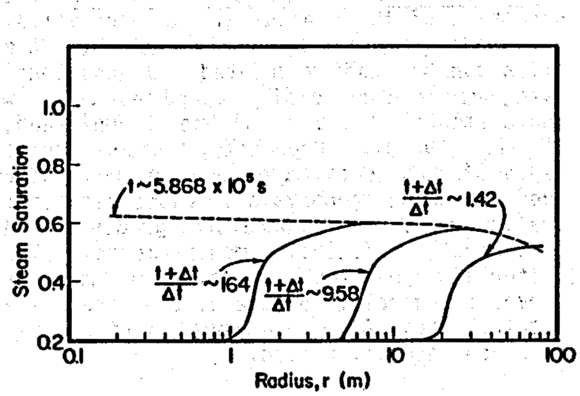

Figure 1. Radial Distribution of Steam Saturation S_g at Selected Times

Figure 1 illustrates one of the cases simulated in which the reservoir, initially boiling everywhere, is produced at a constant rate. The vapor saturation is shown at different times; during pressure buildup after production is stopped, substantial liquid over-recovery is seen to occur. The condensation front eventually engulfs most of the reservoir region affected during the drawdown period.

The numerical simulations presented in the detailed topical report (Garg and Pritchett [1980]) demonstrate some of the difficulties associated with analyzing pressure transient data from hot water and two-phase geothermal reservoirs. Production data (drawdown/buildup) from single-phase hot water and initially two-phase reservoirs may be analyzed in the usual manner to yield kinematic mobility and absolute permeability provided the total formation compressibility is defined properly. Drawdown data from initially single-phase reservoirs which undergo flashing during production can be made to give two-phase kinematic mobility; the buildup data from such reservoirs offer the possibility of determining absolute formation permeability. It is further shown that injection data for single-phase and two-phase reservoirs can be interpreted to give absolute formation permeability; the fall-off data (especially in two-phase systems) appear, however, to be of lesser utility.

Effects of CO_2 Content of Reservoir Fluid The geothermal wells in the Redondo Creek area produce from fractures in the Bandelier Tuff, a thick deposit of welded volcanic ash-flow deposits of rhyolite ash and pumice. Fluid temperatures over the productive intervals of the wells are 260-315°C; fluid salinity is approximately 6000-7000 ppm. The noncondensible gases are ~99 percent carbon-dioxide; the CO_2 mass fraction lies in the range α=0.003-0.015. Geological and geochemical evidence furthermore indicates that the reservoir system extends below the Bandelier Tuff to great depth in an older series of volcanic and sedimentary rocks; temperatures in excess of 315°C are found there.

The thermodynamic behavior of the Baca reservoir fluid may be adequately represented by a mixture of CO_2 and pure water (Pritchett, et al. [1981]). An equation-of-state package for CO_2/H_2O mixtures has been developed and applied to demonstrate that the depth and the lateral distribution of the two-phase region in the Baca reservoir is very sensitive as to the assumed value of α (see Figure 2). Therefore, a reasonably accurate determination of the CO_2 mass fraction is essential to proper characterization of the reservoir system. Consideration of the changing thermodynamic states of a parcel of reservoir fluid as it moves from the reservoir to the surface shows that once it begins to boil, CO_2 is preferentially transferred to the gaseous phase. Consequently, the CO_2 content cannot be determined from pressure/temperature measurement correlations in flowing wells; CO_2 content must be determined directly by chemical analyses of the discharge fluids.

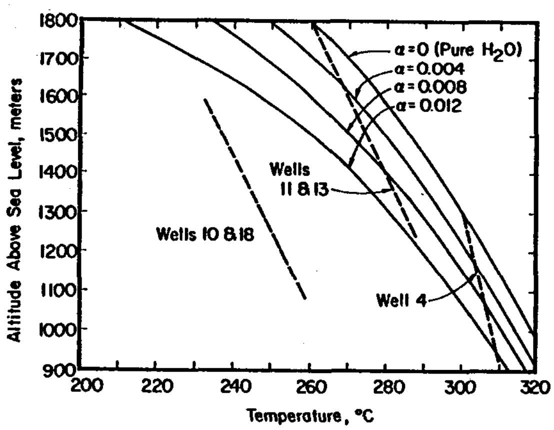

Figure 2. Critical Temperature for Two-Phase Behavior in Baca Field as a Function of Elevation Above Sea Level for Various Assumed Values of the CO_2 Mass Fraction in the Field (α). Dashed Lines Represent Estimated Reservoir Temperatures.

The equation-of-state package was incorporated into CHARGR and a series of calculations made which show that the CO_2 content can have a profound influence on well flow tests. The CO_2 content of the produced fluid may be less than or greater than that of the reservoir fluid. The flowing enthalpy is also strongly dependent on the CO_2 content. It is also shown that the classical interpretation of the drawdown pressure-time data will infer much smaller formation permeability than exists in the reservoir and that the discrepancy increases with CO_2 content.

Interpretation of Downhole Data In many systems, including Baca, most of the permeability is due to the presence of fractures; the matrix (or pore) permeability is often negligible. Because of convective flow within a wellbore penetrating such a system, measured temperature and pressure profiles are related to the formation conditions only at certain feedpoints. Comparison of successive temperature/pressure profiles measured during cold water injection and during the warmup period after injection provide a way to determine the feedpoints. Figure 3 depicts the locations of the wells (drilled prior to 1980) in the Redondo Creek area for which S^3 had data available. S^3 has synthesized information from the well surveys, drilling information and geological correlations to establish that the Baca reservoir is initially two-phase and to construct a conceptual model of the system. This work has been documented in a draft report which has been submitted to the Participant and the Department of Energy for approval (Grant and Garg [1981]).

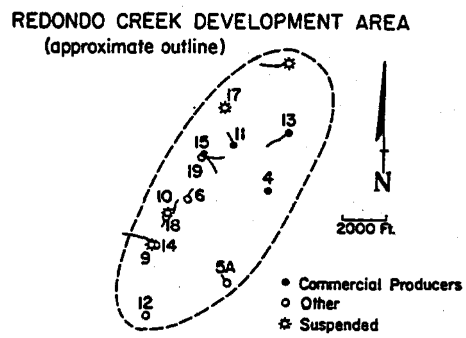

Figure 3. Location of Indicated Baca Wells

Geological and Geophysical Data File The structure of the Geological and Geophysical Data File prepared by S^3 is such that the files can be readily updated and additional data sets can be easily added as any new measurements become available (Goupillaud, et al. [1981]). Presently, three general types of data sets have been entered under the following geophysical classification: gravity, shallow temperature gradient and electrical resistivity measurements. The latter category includes three subtypes of surveys: dipole, dipole-dipole and magnetotelluric. Other subtypes could readily be added later if needed.

Apart from the shallow temperature gradient data, the geophysical data are clearly designed to be used as an early exploration tool. Their value for other purposes appear very limited because of the low density of information in the production area.

Reservoir Data File Computer files of pertinent reservoir data have been developed in a format designed for use in reservoir model simulation studies. These computer files constitute the Reservoir Data File for the Baca project (Rice [1980]). The Reservoir Data File consists of four major files: A General Information File, an Individual Well File for each well in the field, an Interference Tests Data File, and the Core Data File.

The General Information File records definitions, notations and other data pertinent to the understanding of the other three files. The Individual Well File documents data about the well useful for reservoir performance calculations. These files (one for each well in the system) constitute the bulk of the Reservoir Data File. The Interference Tests Data File was intended to be used to record the results of any interference tests performed in the Baca reservoir and the Core Data File was to be used to record data obtained from analyses of all cores taken from the field. The data elements to be included in these two files have been identified, but no data have yet been recorded.

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PACIFIC GAS AND ELECTRIC COMPANY'S GEYSERS PROJECT STATUS

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INTRODUCTION The Geysers Project of Pacific Gas and Electric Company currently has 15 units with a generating capacity of 908 megawatts. In addition, two 110 megawatt units (17 and 18) are under construction, one 110 megawatt Geysers unit (16) is in the licensing process and one more 110 megawatt unit (20) is in the site selection phase. The total operational capacity of the Geysers Project is expected to be about 1,350 megawatts by late 1985. This paper summarizes each project with a more detailed discussion of the site preparation of Geysers Unit 18.

UNIT 16 This unit has been under California Energy Commission (CEC) review since August 1978. The delay has primarily been associated with the routing of the transmission line. Recently, the CEC extended proceedings on the Application for Certification (AFC) decision for 120 days. If the AFC decision is made this year, construction is expected to begin in March 1982.

UNIT 17 The civil foundation and structural steel fabrication work is nearing completion, and the erection of structures, cooling tower and the installation of the electrical and mechanical equipment are about to begin. Commercial operation of this unit is scheduled for December 1982.

UNIT 18 The construction of this unit is about three months behind Unit 17. Problems concerning the construction of this unit occurred mainly during site preparation.

The Unit 18 site was selected after exploratory borings and trenching, mapping, geophysical surveys, laboratory testing of site materials and engineering analysis of laboratory and field data were carried out. The potential for environmental damage and loss of investments due to geologic and seismic hazards were considered in the design. Environmental constraints and potential for landsliding prevented the placing of excavated materials on adjacent slopes and meadows. Consequently, to provide the needed area for the power plant, a crib retaining wall, about 425 feet long with an average height of about 30 feet was proposed.

Owing to the steep terrain and complex geologic features, typical of The Geysers region, it was not possible to determine more accurately the subsurface conditions prior to the start of site construction. The area where the retaining wall was intended was inaccessible to soil investigation equipment. As a result, a high level of engineering judgment was used initially in the wall design with the understanding that the subsurface conditions would be verified during construction.

When construction began, geologic conditions exposed at the plant site were as predicted, but the geologic and foundation conditions at the base of the retaining wall were found to be more adverse than anticipated. Additional borings indicated that the inside face of the wall would require extensive blasting, yet the toe of the wall did not have adequate bearing materials. One alternative solution was to increase the height of the wall to 80 feet at its maximum section in order to reach firm rock. This would increase the extent of blasting and the construction into the winter months. For this reason, an alternative solution was selected by which the plant elevation was lowered by 10 feet and the entire plant layout was moved 25 feet away from the original planned distance from the wall. The wall also was moved 6 feet into the face of the slope, resulting in a crib wall of 44 feet at its maximum section. Significant advantages were realized in time, cost, and risk with a 44-foot wall as compared to an 80-foot wall.

Due to the changed loading conditions (44 feet versus 30 feet originally) the bearing capacity under the crib wall had to be analyzed. Since the overall weight of the crib wall and the backfill behind it were approximately the same as the materials cut from the hill, the problem to be analyzed was mainly in the distribution of the loads rather than in the increase in the overall load.

When excavation of the retaining wall was essentially completed, geologic and foundation conditions were mapped. About ¼ of the base area of the wall consisted of softer, sheared materials with sheared zones and clay seams.

The remaining area consisted of grey, relatively unweathered amphibolite; the conditions were neither bad nor good. Strength analysis of the materials indicated that bearing capacity under the base of the crib wall would be adequate but the in-situ strength of the clay seams could be weakened by winter rains. To alleviate this problem, the wall was built on a thoroughly compacted base of crushed rock with a network of sub-drains. As a precautionary measure, the future behavior of the wall and the foundation conditions are monitored by an inclinometer and peizometer and settlement markers at critical sections of the wall; so far, no significant movement has been observed. Construction of the crib wall and major earthmoving operation was completed in November 1980, before the start of the winter season. Currently, the civil foundation and structural steel fabrication work is in progress. Commercial operation of this unit is scheduled for May, 1983.

H_2S ABATEMENT The abatement of H_2S at The Geysers is a continuing problem only partially resolved. The 15 operating units have several abatement systems as follows:

UNITS	SYSTEMS
13, 14, 15	Surface condenser/Stretford Process; secondary abatement with H_2O_2 and Fe-Hydroxy Acetic Acid
3, 4, 5, 6	
11, 12	$FeSO_4$; H_2O_2; NaOH
9, 10	$FeSO_4$; NaOH
2, 7, 8	$FeSO_4$; EIC demonstration process being installed on Unit 7
1	Natural abatement using direct condenser and cooling tower

Many papers and discussions previously have reviewed the various abatement technologies from either an optimistic or pessimistic point of view. From our experience to date at The Geysers, we have demonstrated that the installed abatement systems are operable, but the capital cost and operational difficulties are more significant than was originally contemplated. The chemical abatement systems used on the direct contact condenser Geysers units result in a high solids content in the cooling water with attendant corrosion and increased maintenance. The surface condenser/Stretford Process/Secondary Abatement System appears to be effective to meet today's regulations; however, corrosion appears to be significant and the capital and operating costs are high. The Stretford Process has proved to be reliable but maintenance is a continuing problem caused by erosion/corrosion and plugging of transfer lines. The EIC process remains to be demonstrated on a full scale at Unit 7 but the ever-present concern is the risk of potential turbine damage due to sulfuric acid and copper sulfate entrainment in the "clean" steam. The Coury Process has not been developed at The Geysers beyond the 1000 lb steam/hour facility that was tested at Unit 7; however, PGandE is carrying out detailed designs for the Coury Process but no commitments have been made for installing a test facility at The Geysers.

In summary, the H_2S abatement continues to remain one of the limitations to geothermal development at The Geysers, whereas the design and construction of The Geysers units are conventional and state-of-the-art at this time. The ever-increasing emission limitations on H_2S have shifted the emphasis at The Geysers from electrical generation to chemical processing. Unfortunately, this trend has not demonstrated any change in direction and will likely increase to result in more chemical operations.

SUMMARY OF UTAH POWER & LIGHT COMPANY

GEOTHERMAL ACTIVITIES

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Utah Power & Light Company's present geothermal activities are concentrated at the Roosevelt Hot Springs area located in southwestern Utah. On September 18, 1980, Utah Power & Light Company (Utah Power) and Phillips Petroleum Company (Phillips) executed a steam sales agreement which established the price that Utah Power would pay for steam energy in the Roosevelt Hot Springs (Roosevelt) area. Under other provisions of the agreement, Phillips dedicated the energy in the resource for electric power generation. Phillips can use the lower temperature heat content geothermal fluids for non-electric uses if authorized by Utah Power.

My discussion will briefly describe the Roosevelt geothermal reservoir, discuss some engineering features of the planned Milford Geothermal No. 1 electric generating unit, and then outline the anticipated program to test the second-generation rotary separator turbine unit.

The Roosevelt geothermal reservoir is located 12 miles northeast of the town of Milford (see Figure 1). The reservoir underlies a part of the Roosevelt Hot Springs Known Geothermal Resource Area (KGRA), which consists of 46.7 square miles in Beaver County, Utah. Phillips holds federal geothermal leases of 70 percent of the participating area, and has been designated as unit operator. Amax Exploration, Incorporated, O'Brien Resources Corporation, and Thermal Power Company, hold lease rights to most of the remaining acreage, which is Utah State owned. The word "Phillips" will be used to represent all resource owners in the Roosevelt reservoir area.

The most significant geological feature at Roosevelt Hot Springs is the Dome Fault, a north-south trending fault manifest on the surface for a distance of approximately two miles. The reservoir is contained in fractures in granite rock to the east of the Dome Fault.

The Roosevelt Hot Springs was a small area of springs discharging sodium chloride water highly charged with silica. At various times, the settlers used the springs in the area for washing, bathing, stock watering, and swimming. The springs were reported to have a small discharge of hot water as late as 1957, but, by 1966, the springs were dry. Small fumeroles emit minute quantities of water vapor and gases at the present time within the spring area.

Earliest drilling for geothermal resources occurred in December, 1967, when Eugene Davie and A. L. MacDonald jointly drilled 80 feet into opaline hot springs deposits in Sec. 16, T27S, R9W. They encountered hot water and plugged and abandoned the hole. They moved the rig 300 feet to the east and drilled a 165 foot hole, which encountered hot water that flashed to steam. The well was plugged and then redrilled in March, 1968, to 265 feet, at which depth the well flowed a mixture of steam and hot water. This last hole was eventually plugged and abandoned with some difficulty. It is this well site that is generally described as the "discovery well" for the Roosevelt geothermal area.

Results of exploration activities conducted prior to the Roosevelt KGRA lease sale in 1974, which was the first to be held in Utah, indicated that the Roosevelt area had exceptional geothermal promise.

After the federal leases were issued in October, 1974, exploration activity shifted to drilling the acquired acreage. During 1975, six exploratory wells and two observation holes were drilled. The commercial discovery Well No. 3-1 was completed near the end of April. Subsequent work in the period from 1976 to the present was designed to further an understanding of the geothermal reservoir.

Tests on Well No. 3-1 indicated a reservoir temperature of 500°F. On a three-hour flow test, this well produced at a total mass flow rate of 600,000 pounds per hour with a steam-to-water ratio of .17. To date, five additional wells indicated to be commercially productive have been completed by Phillips and other resource operators within the Federal Unit.

The Roosevelt Unit was the first geothermal unit approved by the United States Department of the Interior, and it was utilized in April, 1976.

At the present time, eleven geothermal test wells have been drilled within the KGRA. Six of the wells are considered capable of producing fluid in commercial quantities: Phillips No. 3-1, No. 54-3, No. 13-10, and No. 25-15; Amax-Thermal Power-O'Brien (ATO) No. 14-2 and No. 72-16. Phillips Well No. 12-35 is productive but presently not commercial. Four wells have not encountered the geothermal reservoir: Phillips No. 9-1 and No. 82-33; Getty Oil Company No. 52-21; and ATO No. 24-36. Phillips Well No. 3-1 was completed with small diameter casing and is not proposed as a producing or injection well in this plan, but will be retained as an observation well.

In addition to the deep tests, eight observation wells ranging in depth from 1,760 to 2,317 feet have been drilled in the area.

For Milford Geothermal No. 1, a 20 megawatt (MW) electric generating unit, it is planned that two existing wells (54-3 and 13-10) and two new production wells, designated as A-1 and A-2, as shown on Figure 2, will be used to supply the required steam flow. Three existing wells (82-33, 14-2, and 12-35) will be used to inject cooled geothermal fluids back into the fringes of the geothermal reservoir. The operation of three of four production wells and two of three injection wells should provide adequate capacity to operate the 20 MW unit at its maximum capability.

The generating plant will occupy the larger portion of a ten-acre parcel of land located in the south central area of Sec. 3, T27S, R9W. This site is gently sloping to the west and is covered with sagebrush. The site is located on federally-owned land, and we are discussing a 30-year lease with a preferential renewal right with United States Geological Survey (USGS) and Bureau of Land Management (BLM). A 46-kilovolt transmission line is located just one-half mile south of the proposed plant site.

This first generating unit will be powered by steam manifolded from single-flash wellhead steam separators. The geothermal liquid will be collected and then pumped to the injection wells identified above. The single-flash, 20 MW generating unit was selected as a compromise to hold down initial investment while providing generating capacity that would use sufficient reservoir fluid to provide meaningful capability and fluid characteristics data.

We have accomplished many significant milestones to date. On September 18, 1980, we executed a steam sales agreement with Phillips. That agreement was approved by the Utah State Public Service Commission in December, 1980. Then, in early January, 1981, requests for proposals were mailed to six engineering firms, and on March 6, 1981, Gibbs and Hill, with offices in San Jose, California, were selected to begin engineering the Milford Geothermal No. 1 generating unit. Applications to USGS and BLM were filed in January, 1981, to occupy the land for the plant site. If all required permits and authorizations are obtained on time, the plant should begin operations by late 1983 or early 1984.

In the near future, it is our plan to participate with Phillips, EPRI, and Biphase Energy Systems to test the second generation, 54-inch Rotary Separator Turbine Unit at Roosevelt. The Rotary Separator Turbine Unit is capable of separating steam from water, producing useable shaft power from either or both of the steam and water, and repressurizing the liquid for transport to the water injection well.

This device offers the potential of producing more electrical energy per pound of geothermal fluid than other conversion concepts, and it can be sized to utilize the complete flow capacity of a single well. Therefore, we have generically called it a wellhead generating unit. We are interested in this concept because collecting electricity from several wellhead generating units may prove to be more economic than collecting steam from several wells and routing it through large diameter pipelines to a single steam turbine.

To test the Rotary Separator Turbine Unit, we have planned a three-phased program that minimizes early investment risk, while ultimately gathering needed reservoir data and proving the operating success of the entire Rotary Separator Turbine device when coupled with a steam turbine system.

Phase I is planned as a test of the separator at Phillip's existing Well 54-3 and test site. An injection pipeline to Well 82-33 is in place; therefore, the only capital expenditures required would be for local connecting piping and to construct a short transmission line from the test site to the nearby transmission line. It is expected that the test unit will generate approximately 1,600 kW.

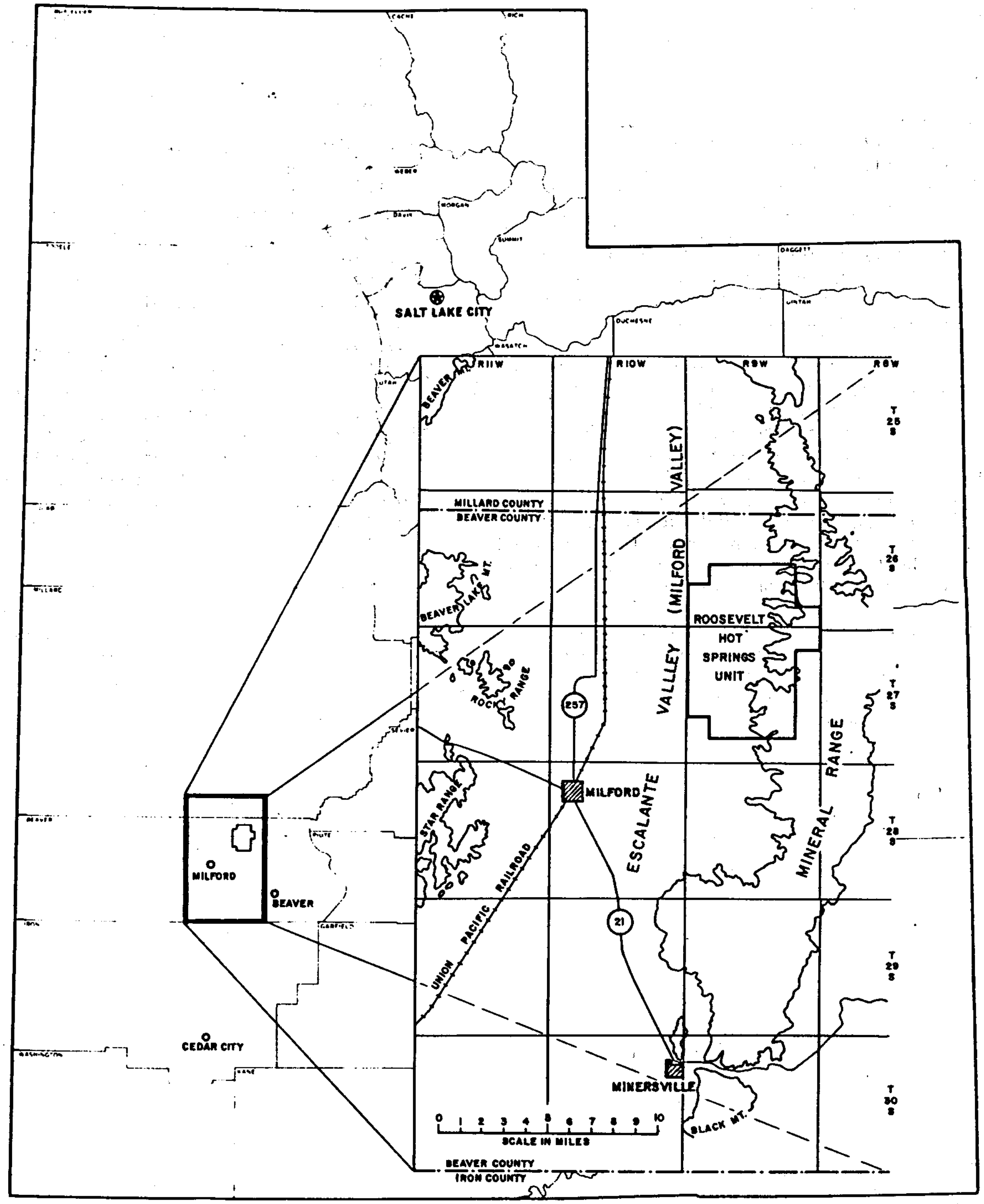
A Plan of Operation, Utilization, and a Sundry Notice were submitted to USGS early in June, 1981. They have prime responsibility for all governmental agencies, and are coordinating the involved process of obtaining individual government approvals. This authorization process is proceeding smoothly, and we are hopeful that we can have all required approvals in time to begin testing operations by October, 1981.

Phase II test operations would be conducted to test the separator unit for a longer period of time to accumulate performance and endurance data and to gain reservoir data in a different area of the reservoir. New facilities that will be required for this test phase will include a production well, injection pipeline, injection pumps, and electrical transmission line. It is planned that the test would be conducted during the spring and early summer of 1982.

Steam turbine and auxiliary equipment will be purchased and added to the rotary separator turbine unit to test the complete wellhead generator unit. This combined rotary separator and steam turbine unit will generate nearly seven megawatts of electrical energy, and its operation will initiate Phase III test operations. If equipment can be procured in an expeditious manner following Phase I and II tests, Phase III operations would be conducted in mid-1983.

The benefits of this wellhead geothermal generation development program are expected to be more efficient use of the geothermal resource, or more kilowatts generated per pound of geothermal fluid utilized. Additionally, wellhead generating units are somewhat portable and can be moved if a localized reservoir problem occurs. This benefit reduces loss of investment risk. Lastly, wellhead geothermal units may be more aesthetically pleasing because long and large-diameter steam pipelines are not routed on the surface. Electrical transmission lines can be placed underground, thereby leaving only small-diameter injection pipelines above ground. For these reasons, Utah Power & Light Company has chosen to participate in the rotary separator turbine development program.

In summary, we are committed to geothermal development. We are encouraged concerning the capacity and fluid specifications at Roosevelt geothermal reservoir, and look forward to developing this geothermal reservoir as an economic electric generation resource.



ROOSEVELT HOT SPRINGS UNIT
LOCATION MAP
BEAVER COUNTY, UTAH

FIGURE I

ROOSEVELT HOT SPRINGS
GEOTHERMAL AREA

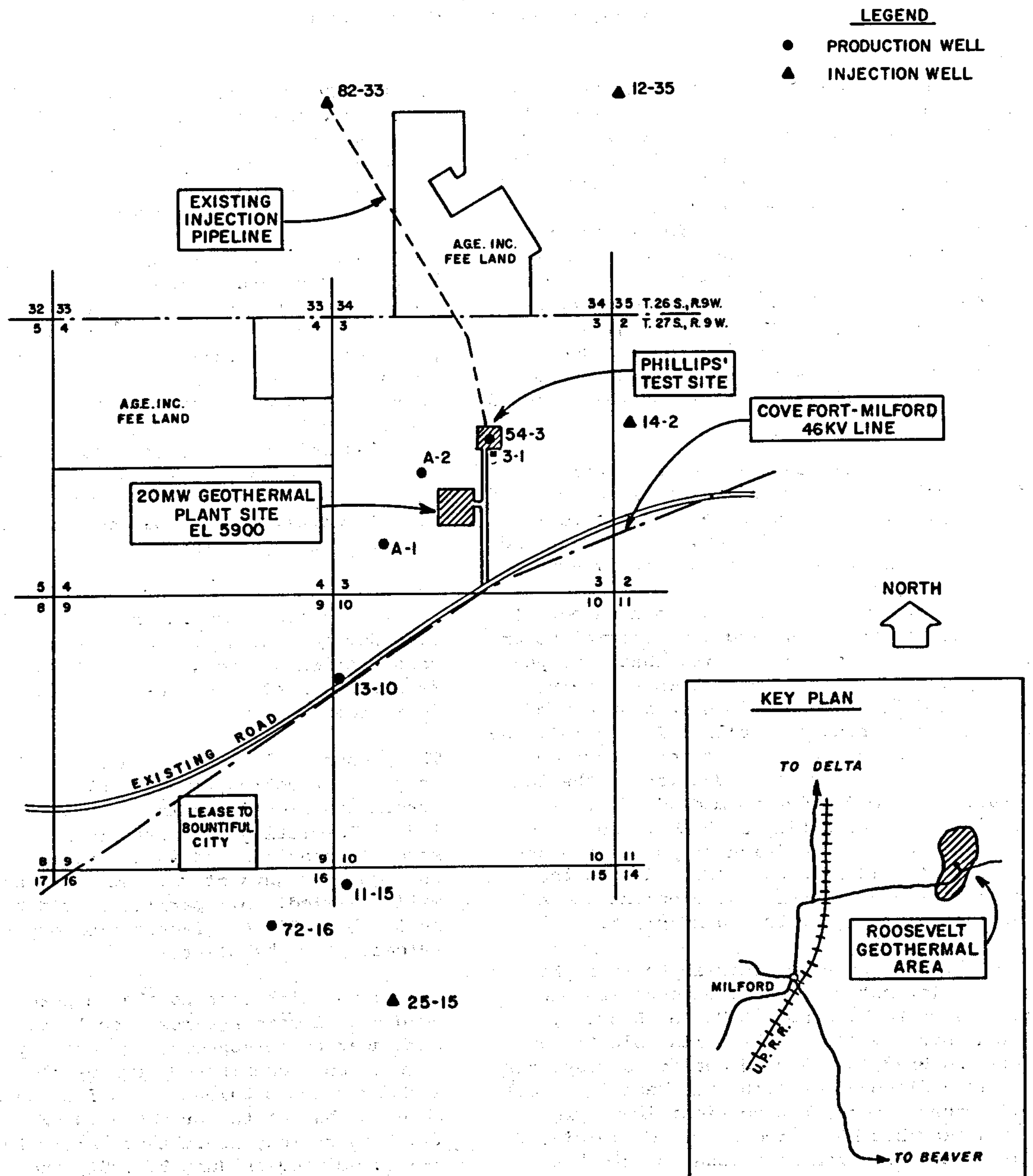


FIGURE 2

A 10 MW BINARY GEOTHERMAL PLANT

FOR NORTHERN NEVADA

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Sierra Pacific Power Company in conjunction with Portland General Electric Company, Eugene Water and Electric Board, Pacific Power & Light Company, and the Sacramento Municipal Utility District, are in the process of locating and building a 10 MW Binary Geothermal Power Plant in Northern Nevada. Negotiations for a resource are in progress. Environmental monitoring is being carried out at several sites. A contract has been executed with HBA Energy Recovery System for preliminary plant engineering, detailed engineering, and plant fabrication. A geothermal brine test unit is in the field to evaluate the scaling properties of brines on the proposed binary heat exchanger.

As soon as resource negotiations are satisfactorily completed the project expects to obtain the necessary permits and move into the construction phase. Final design, procurement and construction are expected to take two years.

The NORNEV group has been studying a number of alternative plans for siting a geothermal power plant for several years. During that same period resource developers have been actively engaged in drilling operations in a number of locations developing new wells. In general, the Nevada reservoirs appear to be hot water resources with significant production in the temperatures from mid 300°F to mid 400°F's. A preliminary try at siting a 50 MW flash steam plant resulted in a decision to pursue the development of a 10 MW binary plant due to the present degree of resource development and a lower capital cost for the 10 MW plant.

The geothermal resource areas in Northern Nevada where development work has been done are Steamboat, Desert Peak, Humboldt House, Beowawe, Wabuska, Dixie Valley, Salt Wells, Big Smokey Valley and Brady's. A good deal of survey work and some additional drilling has been done outside of these areas, but no significant production find has been announced. Commercial development for Northern Nevada to date has been for direct heat applications, distillery operations, and onion drying.

The NORNEV group is presently negotiating for a resource where they can site the 10 MW plant. The plant currently being designed by HBA will be modular and skid mounted, requiring a minimum of field erection labor and offering the possibility of relocation should it become necessary.

The plant will receive hot brine from a resource and return cooled brine to the resource owner for reinjection or other use. The hot brine will be used to drive a binary cycle power plant which uses iso-pentane, propane, or isobutane as a working fluid. The present concept is to have a plant which can be started and put on line by two men. It will run unattended and it can be shut down remotely. In view of the remote locations of probable plant sites, and the problems of manning small generating units, it will be essential to have a trouble-free operation.

The present plant schedule envisions a plant ready to operate toward the end of 1983. Plant site development will proceed concurrently with construction of the WHG so as to have the site facilities ready when the plant equipment is delivered.

The present milestone schedule has the ownership, construction, operation, and resource agreements signed and in place by September 1981. Permitting is currently in progress for several locations and when a resource agreement is signed, rights of way and final applications will be filed. All permits should be in place by October 1981 and fabrication orders will be released for the plant.

Concurrent with signing the resource agreement, NORNEV will commence resource testing for heat exchanger performance. The recently constructed test unit consists of two parallel heat exchanger loops which have a flow path comparable to that of the proposed 10 MW unit. The first thirty-day field test partly funded by EPRI concluded on June 8, 1981, and the results of the tests are being evaluated.

THE IMPACT OF THE CORPORATE SHIFT TOWARD RENEWABLES ON SOUTHERN CALIFORNIA EDISON'S GEOTHERMAL PROGRAM

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Introduction On October 17, 1980, Southern California Edison announced a major shift toward the development of renewable and alternative energy resources. A goal was established that 1900 MW or approximately 30% of new capacity required to come on-line during the decade of the 1980's, will be comprised of wind, solar, fuel cells, co-generation, hydro and geothermal. As a result, the geothermal contribution to Edison's generation resource plan increased from 170 MW to 420 MW on-line by 1990.

In order to meet this accelerated geothermal development schedule, several substantial new efforts have been initiated, drawing upon many resources within the Company. These new activities are proceeding in concert with the ongoing power plant projects at Brawley, Salton Sea and Heber as well as other ongoing corollary geothermal endeavors.

Brawley Unit 2/Generic High Temperature Resource Power Plant Scoping Study In an effort to proceed as efficiently as possible with the commercial development of the Brawley resource based on existing contracts, planning sessions have been initiated with Union Geothermal to review the status of our parallel feasibility evaluations based, primarily, on the performance of Brawley Unit 1. It is currently our plan to work toward a 1986 operating date for a 50 MW unit at Brawley. Over the next two years, Union will continue to test and demonstrate brine handling systems and perform confirmation drilling, resource evaluations and develop a steam production system design for a 50 MW unit. Edison will continue to evaluate the operation of the Brawley Unit 1 power plant. In addition, Edison's R&D Organization has initiated an in-house conceptual engineering effort to scope out the major elements of a 50 MW, high temperature resource power plant including a conceptual cost estimate, schedule and design. A major task included in this study is the review, on a common basis, of several cooling/water conservation systems including the Tower Systems Binary Cooling Tower, the CBI ammonia dry cooling system, a wet/dry system utilizing condensate, a unique blowdown concentrator utilizing heat from turbine exhaust steam, a dry steam condenser and systems to use secondary sewage water and New River water. This study will serve as a preliminary basis for planning future units at high temperature resources where the developer provides steam "at the fence line" as is the case under our existing contracts with Union at Brawley and Salton Sea.

Geothermal Solicitation On February 17, 1981, requests for geothermal proposals were mailed to 80 firms active in the geothermal industry. The request solicited firm offers by potential geothermal small power producers including cooperative ventures involving participation by Edison. It is the objective of the solicitation to further stimulate and accelerate the development of geothermal resources, in the Imperial Valley and elsewhere, beyond the scope of our current programs if feasible. The type of project is left open and could range from Edison buying electricity, to buying steam or brine, to participating in an integrated development program. First round proposals were requested by May 15, 1981; however, additional proposals will be accepted beyond that date.

Modeling Shortly after the policy shift toward renewable/alternative energy projects, it became evident that additional tools would be required to rank alternative technologies and evaluate specific projects. In the case of geothermal, Edison had been looking primarily at our Heber 41 MW double-flash project as the generic example of commercial geothermal power generation for the Edison system. Only rudimentary analysis of commercial developments at the Salton Sea, Brawley and other areas had been performed, since they are in the exploration/research phase. With the accelerated goal of 420 MW of geothermal capacity on-line by 1990, it became necessary to look further ahead in the nearer term in terms of analyzing a complete matrix of potential commercial geothermal developments and project structures. The goal was to develop the capability to more effectively model, evaluate and rank renewable/alternative projects with respect to key criteria such as technical feasibility, public acceptability, financial incentives and ownership options, while considering the significant technological and financial uncertainties associated with the development, cost, financing and operation of geothermal facilities as well as other new technologies.

The evaluation approach includes: 1) an assessment of the technical feasibility (commercial availability, reliability, probabilistic analysis of uncertainties); 2) development of the basic conceptual design, if possible; 3) sensitivity analysis of engineering economics (levelized capital, fuel and O&M costs treated probabilistically to evaluate the uncertainty of cost projections); 4) review of financial incentives and ownership options (full or partial Edison ownership, Edison subsidiary ownership, non-utility ownership, traditional financing, project financing, leasing, etc.); 5) financial analysis (quantitative and qualitative evaluation of the risk and uncertainty related to cash flow, alternate ownership scenarios from both Edison's and an entrepreneur's perspective, in terms of minimum revenue requirements, net present value, return on investment, sensitivity analysis); and 6) licensing (review of potential legislative and regulatory constraints).

A review was made of available computer programs with respect to the identified modeling needs and criteria established including the ability to handle probabilistic analysis, the ability to perform sensitivity analysis, and flexibility. Based on this review, it was decided to develop the model in-house utilizing a high-level financial modeling language rather than to procure a pre-packaged model.

To date, the basic model has been developed and several geothermal cases have been evaluated. Typical graphical printouts include: 1) revenue and fuel cost per kWh over project life; 2) benefit to cost ratio over project life; and 3) revenues, expenses and net income over project life. This output was developed varying several parameters including fuel cost escalators and ownership options.

This modeling tool is proving to be invaluable in evaluating proposed geothermal projects, developing negotiation positions, and forecasting impacts on the Company and the ratepayer of proposed projects and development scenarios.

Transmission Planning Edison's Electric System Planning group has analyzed the transmission requirements to deliver power from the future SCE geothermal units in the Imperial Valley to the Edison System. As we currently have no transmission tie with the Imperial Irrigation District System, the power from Brawley Unit 1 is being sold to the IID. It is, of course, our objective to export substantial quantities of geothermal power from the Imperial Valley. While the early plants will likely be integrated with the existing IID system with at least a portion of their power being exported with minor improvements to existing systems, it is anticipated that with the advent of Brawley Unit 2 projected for 1986, new transmission facilities will be required.

Edison is working with the Los Angeles Department of Water and Power, the Western Area Power Administration of the DOE, the California Department of Water Resources, San Diego Gas and Electric, the Cities of Glendale, Burbank and Pasadena, Riverside, Anaheim, The Metropolitan Water District, Arizona Public Service, and in particular with the IID in developing a phased, long-range plan which will mutually serve the needs of all parties involved.

Mammoth District Heating Update In 1977, the Ben Holt Co. in cooperation with Edison, completed for ERDA, a study assessing the feasibility of utilizing the geothermal resource at Casa Diablo to provide space and water heating at the ski resort community of Mammoth Lakes in the Eastern Sierra. Edison's analysis of that study determined that it would not be cost effective for Edison to develop the system at that time, primarily due to the high capital cost of the system and the low operating factor.

In light of Edison's recent increased emphasis on the utilization of renewables, together with a substantial increase in the cost of electricity at Mammoth (which utilizes primarily electric heating), and new tax incentives, regulations and financing alternatives, the concept was re-evaluated.

A revised implementation schedule was developed based on a 1987 operating date for a 52 MW thermal system. Our latest projections of load growth, escalation rates, fuel costs and economic evaluation factors were incorporated. A revised capital cost ($45,000,000 including brine production facilities, heat exchangers, pumps, storage and distribution facilities) and associated carrying charges, O&M, and energy savings (incremental fuel cost) and capacity savings were tabulated on a year-by-year basis. The greatest savings were the incremental fuel costs avoided or replaced by geothermal energy. The savings associated with reduction in system load was not as great as hoped; the capacity saved by the heating system in Mammoth during the summer is quite small. The value to Edison, therefore, as a summer peaking utility, is correspondingly small.

The analysis indicates that the savings begin to exceed the costs after nine years of operation; the savings become substantial in the later years of the project. The "bottom line," however, is that the present worth of the costs exceeds the present worth of the savings by a substantial margin.

This "re-look" was based on conventional financing and ownership assumptions. It is planned to use the modeling techniques described earlier to evaluate alternative project configurations based on the updated economics to determine if there are more effective approaches to developing the use of the Casa Diablo resource for district heating.

Mexican Geothermal Purchase Over and above the 420 MW goal for installed geothermal capacity on the Edison system, a power purchase agreement was executed in November 1980 between Edison and the Comision Federal de Electricidad de Mexico giving Edison purchase rights up to 70 MW of electricity beginning in 1984. Another 260 MW in purchase contracts with CFE are also anticipated. This power will be generated by new geothermal units to be built near to the four very successful existing units, totaling 150 MW at the Cerro Prieto geothermal resource area, located approximately thirty miles south of Mexicali. In conjunction with this agreement, several committees have been established to periodically discuss the project interfaces and review the progress of generation and transmission facility development. We look forward to a long and mutually beneficial program with CFE which has been a true pioneer in the effective development of geothermal resources.

Power Plant Projects Update The three Edison power plant projects, Brawley, Salton Sea and Heber have been described previously (1). The following will serve as a progress update.

Brawley 9 MW Unit This unit began firm operation on July 29, 1980. To date, the plant has been operating at an average capacity factor of approximately 52% (2). The unit has reached full rated gross output capacity of 10 MW but has generally operated at approximately 7.5 MW. The geothermal steam produced by Union Oil Company has been of substantially higher purity than originally anticipated. Inspections of the generating unit turbine, piping and other equipment indicate that scaling and corrosion are within acceptable limits.

An ongoing assessment program monitors all relevant technical, economic and environmental parameters needed to evaluate the feasibility of follow-on commercial generation at Brawley.

On May 1, 1981, the Los Angeles Department of Water and Power became a 50% owner in the Brawley Unit 1 power plant program. LADWP and potentially other municipalities including the cities of Pasadena, Burbank and Riverside will share in the costs and revenues associated with the project.

Salton Sea 9 MW Unit Construction of this unit was initiated on February 2, 1981. As of this writing, the design by Fluor Power Services is approximately 85% complete, with construction about 15% complete. The unit is scheduled to begin initial operation in April 1982, with firm operation scheduled for July 1982.

Heber 41 MW Unit Preliminary engineering has been completed, with final engineering and construction ready to begin. An Application for Public Convenience and Necessity was filed with the California Public Utilities Commission (CPUC) on March 7, 1980. On May 19, 1981, the CPUC denied the application based on high costs. As of this writing, it is uncertain what the next step will be.

Summary Remarks Edison's decision to aggressively pursue the development of geothermal resources, as characterized by exploratory drilling activities and resource/technology development programs in the early-to-mid-70's, the initiation of power plant programs by the late 1970's, and the operation and certification activities currently in progress, has taken the program through the lower knee of the S-shaped learning curve. The activities of the last decade have placed us on the steepest incline of the curve. We are learning a great deal very quickly. Brine utilization technology is being improved and demonstrated. Alternative project configurations are being modeled and evaluated. It remains to determine what the final economics of hot water geothermal will be, and what economics are acceptable to the ratepayer and the companies involved.

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UTILITY GEOTHERMAL PLANS - TEXAS AND LOUISIANA

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Leading candidate for developing geothermal energy in the Gulf Coast area is the geopressured aquifer system extending under the Louisiana and Texas Gulf Coasts. This aquifer system is characterized by high pressure, moderate temperature, and contains dissolved gases, mostly methane.

Preliminary investigation has involved screening of thousands of petroleum well logs using sophisticated computer techniques which have identified several prime locations for actual drilling. Despite all the preliminary information from these scources it is necessary to produce brine from the formation to evaluate the aquifer characteristics. The Department of Energy has four design wells under way or completed at present. One of these is Pleasant Bayou No 2 and is located in Brazoria, Texas. In Louisiana the wells are known as Sweetlake, Rockefeller Refuge and Parcperdue.

Pleasant Bayou No 2 in Brazoria County, Texas, was completed in 1979. Preliminary testing up to a flow of 20,000 barrels per day (BPD) was done in 1980. The testing to design capacity - 40,000 BPD - is scheduled to begin this week. The testing equipment has been redesigned, a second separator has been added, and arrangements to sell the produced gas have been made. The testing arrangement, beginning with the usual christmas tree consists of a long radius expansion bend from the flow outlet of the christmas tree to an anchor point before entering the manual valve and adjustable choke, used for controlling the flow to the separator installation. The expansion bend accommodates the growth and contraction of the tubing and other well material as the temperature changes because of flow conditions.

On the way to the separator area the piping is tapped for a bypass valve which allows flow to be bypassed around the separator installation directly to the disposal well, Pleasant Bayou No 1, located some 500 feet from the production well.

When the flow line reaches the separator area, it divides and goes through two separators in parallel. Each is rated at approximately 20,000 barrels per day with a working pressure of 1315 psi at 300 F. Level controllers on each separator control the outflow of brine from the separator, while pressure control valves release gas from the upper section of the separator to maintain the set pressure. The brine outlets join downstream of the level control valve and go back to the disposal well. The gas streams from the two separator pressure control valves join and enter the air cooled gas cooler where the fan forces cooling air across the tubing containing the gas. Next is a glycol gas dehydrator which includes a separating column to remove the glycol from the stream.

The gas is then ready for the sales meter which has been installed to permit marketing the separated gas into a nearby pipeline. Payment for the gas is on a Btu basis, hence the 10% or so carbon dioxide content is not significant since the flow is very small compared to that in the pipeline which is accepting the gas.

The revised test installation accommodating the second separator is due to begin operation in early July. Long term testing up to the design flow of 40,000 BPD should now be possible. This will enable a more comprehensive evaluation of the reservoir. With this information, evaluation of the economics of power production from the geopressured fluid should be possible.

In Louisiana, the Magma Gulf, Technadril/ Fenix & Scisson - Sweetlake well has been completed and was perforated at the desired depth just last week. A nearby disposal well had been previously completed.

The third design well known as DOW CHEMICAL - L R Sweezy (Parcperdue) has reached total depth after two drilling incidents, each of which required side tracking. This well is currently being completed for flow testing in late July.

Technadril/Fenix & Scisson - Gladys McCall/ Rockefeller Refuge is the fourth design well and is now drilling at about 7,500 feet. No major problems have been encountered.

Other design wells have been planned but are on hold due to federal budget uncertainty.

Another source of information on these aquifers is the Wells of Opportunity program. By this means the DOE seeks gas or oil wells which turn out to be dry holes, that the owner will release for perforation and flow testing by DOE to learn something of the aquifer characteristics before the well is finally plugged. These wells can provide only limited information because of their small size compared with the design wells which are drilled and equipped for very high brine flow rates. It is sometimes possible to determine quickly that a reservoir is not a producer, but to prove a good well takes a long time at high flow rates. Wells of Opportunity allow for testing a number of formations at modest expense compared with the cost of one design well.

Eight Wells of Opportunity have been acquired and tested or are now being prepared for test. Two more wells are expected to be available before the end of 1981.

It appears that the geopressured resource is widely dispersed and may lend itself to production of the dissolved methane content in the brines. Relatively small wellhead generating units, capable of being relocated as the aquifers decline in productivity, have been suggested for recovering energy from brine pressure and temperature. Further evaluation will be possible only when testing of sufficient numbers of wells to allow assessment of formation permeability, reservoir flow characteristics and reservoir life has been done.

EPRI Report AP-1457, July 1980, Geopressured Energy Availability, covers Research Project 1272-1. It provides excellent background information on the subject, although only very preliminary testing of the Pleasant Bayou well had been done when this project was completed.

GEOTHERMAL DEVELOPMENT PLANS IN CERRO PRIETO BAJA CALIFORNIA, MEXICO

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This paper represents the status of the Cerro Prieto Geothermal Field and the short term expansion plans. Cerro Prieto has been divided in three areas which represent the different expansion stages: Cerro Prieto I.- Started commercial operations in 1973 and its actual generating capacity is 150 MW, which will be increased with an additional 30 MW in July 1981. Cerro Prieto II and Cerro Prieto III.- With a generating capacity of 220 MW each, will start commercial operations in 1983 and 1984, respectively.

Cerro Prieto I The actual technical data of the field is:

Number of wells in operation	30
Depth of the producing zone	1500 m
Total mixture production (water-steam)	5000 ton/hr
Water/steam ratio	2.33
Average mixture enthalpy	313 kcal/kg
Range of reservoir temperatures	250-350°C
Total dissolved solids (T.D.S.) in separated water at atmospheric pressure	2.5% weight

Steam is separated from the water-steam mixture in a centrifugal separator installed at the well-head, at a pressure of 8 kg/cm^2 absolute. This high pressure separated steam feeds Units 1, 2, 3 and 4, with a capacity of 37.5 MW each. The separated water from all the wells in C.P. I is conducted to a two-stage flashing plant; medium and low pressure steam are produced at pressures of 4.7 and 2.5 kg/cm^2 abs., respectively. This steam will feed the 30 MW low pressure unit known as 5th Unit. The high pressure turbogenerators have single-cylinder, double-flow turbines, inlet pressure of 6.3 kg/cm^2 abs., and outlet pressure of 0.108 kg/cm^2 abs. The low pressure turbogenerator has a single-cylinder, double-flow, mixed pressure turbine; inlet pressure of 4.3 and 2.1 kg/cm^2 abs., and outlet pressure of 0.112 kg/cm^2 abs. Each unit has a direct contact barometric condenser.

Cerro Prieto II With a capacity of 220 MW, will initiate commercial operation in 1983. The wells that will feed the C.P. II and C.P. III power plants are located NE of C.P. I. They will produce from a deeper and better thermal features aquifer:

Depth of the producing zone	2200-2500 m
Average mixture enthalpy	340 kcal/kg
Range of reservoir temperature	310-350°C
T.D.S. in separated water at atmospheric pressure	3.65% weight

In order to have C.P. II in operation, it will be necessary to drill 25 wells, from which 20 will be producing and 5 as stand-by. Up to date 12 wells have been drilled, from which 7 have been evaluated and their production characteristics are listed in Table 1.

The steam separation system will be in two stages, both will be in the well-head using centrifugal separators. The separation pressure in the first stage is expected to be in the range of 11.5 to 14.5 kg/cm^2 abs., and for the second stage from 3.5 to 6.0 kg/cm^2 abs. The steam required to feed a 110 MW unit is about 650 ton/hr of high pressure and 109 ton/hr of low pressure steam.

Each 110 MW generating unit consists of two 55 MW turbines (tandem compound), single cylinder, double flow and mixed pressure; inlet pressure of 10.75 and 3.16 kg/cm^2 abs. for high and low pressure, respectively; outlet pressure of 0.1209 kg/cm^2 abs. Each turbine has one low level jet condenser and a vacuum system consisting of one centrifugal type horizontal gas compressor driven by a single-flow high-speed, back pressure turbine. Gas ejectors are used during start-up and when one compressor is out of service.

Cerro Prieto III With a capacity of 220 MW, will initiate commercial operation in 1984. The same number of wells will be necessary. At present time 10 wells have been drilled, from which 2 have been evaluated. The steam separation system and the power plant will be similar to that of Cerro Prieto II.

TABLE 1

CERRO PRIETO II WELL DATA

WELL	Orifice Ø"	Pc kg/cm^2 (g)	PRODUCTION Water	Steam	Mixture	ENTHALPY kcal/kg
M-149	4 1/2	20	121	54	175	336
M-129	2 7/8	80	148	102	250	385
M-147	2 7/8	85	145	105	250	390
M-169	3 7/8	45	180	70	250	330
T-366	3	64	168	82	250	345
T-388	3	60	165	85	250	363
M-93	5	21	168	79	247	314

MEAGER CREEK THERMAL PROJECT UPDATE

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The Meager Creek area and the Meager Mountain volcanic complex, located in the Coast Range Mountains, are about 160 km north of Vancouver. Since the early work in 1974, two potential geothermal reservoirs were identified on both the north and south sides of the volcanic complex. The south reservoir, where most of the work was done, is within crystalline basement rocks on the flanks of the pliocene-to-recent volcano. Temperature gradients in shallow diamond drilled holes are in a range of 90 to 700°C per kilometer. Production sized deep drilling and testing to assess the reservoir will be initiated during 1981.

THE PARTITIONING OF HYDROGEN SULFIDE IN
THE CONDENSER OF GEYSERS UNIT 15

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Introduction. Geysers Unit 15 was the first of the surface condenser equipped geothermal units to go on line at The Geysers Powerplant of The Pacific Gas and Electric Company. This occurred on July 25, 1979[1].

Units 1 through 12 have contact condensers. The switch to surface condensers was motivated by considerations of hydrogen sulfide emission abatement. In the contact condensers there is a large liquid to vapor ratio, and about 75% of the hydrogen sulfide that is present in the geothermal steam supply ends up dissolved in the cooling water. Once in the cooling water, it is emitted to the atmosphere from the cooling towers unless further "tertiary" abatement is employed.

It was reasoned that, because the liquid to vapor ratio in a surface condenser would be smaller by about a factor of twenty-five than in a contact condenser, most of the hydrogen sulfide would remain in the vapor phase and leave by way of the condenser vent-gas rather than dissolving in the condensate. Each of Units 13, 14, and 15 is equipped with a Stretford Unit which removes the hydrogen sulfide from the vent-gas and converts it to elemental sulfur by reaction with air. Therefore, that part of the hydrogen sulfide which leaves the condenser with the vent-gas is not emitted to the atmosphere. In the absence of tertiary abatement, that part of the hydrogen sulfide that dissolves in the condensate is emitted to the atmosphere. In practice, Unit 15 is operated with an effective means of tertiary abatement (addition of hydrogen peroxide to the condensate to destroy the hydrogen sulfide), but this is expensive.

The Geysers is unusual in that the steam there contains a significant concentration of ammonia (Table I). Ammonia increases the concentration of hydrogen sulfide in the condensate by increasing its pH and, thereby, increasing the solubility of hydrogen sulfide in it (see below). This effect, which was earlier predicted and discussed[2], limits the effectiveness of surface condensers in shifting the hydrogen sulfide to the vent-gas stream.

TABLE I

Steam Compositions Used to Model Geysers Unit 15

	Premodification		Postmodification	
	ppmw[a)]	mmoles/kg[b)]	ppmw	mmoles/kg
H_2S	163	4.8	255	7.5
NH_3	88	5.2	128	7.5
CO_2	3260	74.0	3260	74.0
H_3BO_3	167	2.7	167	2.7
N_2[c)]	--	33.8	--	33.8
O_2[d)]	262	8.2	262	8.2

Notes to Table I:

a) ppmw = part per million by weight = 1 mg/kg.

b) mmoles/kg = mg-moles/kg = millimolal.

c) In modeling, "N_2" represents the sum of N_2, A, H_2, and CH_4 actually reported in the steam analysis.

d) O_2, and part of the N_2 are from an air leak in the turbine gland seal. The composition of the motive steam to the gas ejectors is not affected by this air leak. In that case, "N_2" = 3.2 mmoles/kg and O_2 = 0.

In early 1979, PG&E contracted with the Oakland Office of the U.S. Department of Energy (SAN) to have the Lawrence Berkeley Laboratory provide services in support of PG&E's inhouse program of geothermal research and development. The first assignments given to LBL were to write a computer code that would enable the partitioning and transport of hydrogen sulfide and other gases within the condensers of a geothermal powerplant to be usefully modeled, and to apply this code to Unit 15. The results of this work are reported here.

Related modeling work on contact condensers, and experimental work on the catalytic air oxidation of hydrogen sulfide will be reported on elsewhere[3].

Basic chemical considerations. Ammonia increases the solubility of hydrogen sulfide in the condensate by reacting with it as a base:

$$H_2S + NH_3 \longrightarrow HS^- + NH_4^+$$

Essentially, the ammonia makes hydrogen sulfide to go into solution as HS^- as well as H_2S. The extent to which ammonia increases the solubility of hydrogen sulfide is reflected by the pH of the condensate. At typical condenser temperatures (about 50° C) the pK_a of H_2S is about 6.7. Therefore, at pH 6.7 the concentration of HS^- in solution is equal to that of H_2S, and the total solubility of hydrogen sulfide is twice what it would be at a pH value low enough for the concentration of HS^- to be negligible; for example, at pH 5, which would be a typical value of condensate pH in the absence of ammonia. At pH 8.7, the solubility of hydrogen sulfide is about one hundred times greater than it would be at low pH.

The range of pH values encountered in the Geysers Units' cooling water and condensate is about 7.0 to 8.7. In the absence of ammonia, the condensate pH would always be less than 6.

Carbon dioxide is an acid gas and, in principle, it ought to reduce the solubility of hydrogen sulfide by decreasing the pH of the condensate. Carbon dioxide dissolved in the condensate may lower the pH by reacting with water to produce carbonic acid which then releases a proton:

$$CO_2 + H_2O \xrightarrow{k_1} H_2CO_3 \qquad (1)$$

$$H_2CO_3 \longrightarrow HCO_3^- + H^+$$

or it may react with hydroxide ion to give bicarbonate directly:

$$CO_2 + OH^- \xrightarrow{k_2} HCO_3^- \qquad (2)$$

However, the effect of carbon dioxide is limited by the slow rates of reactions (1) and (2). At 51° C, $k_1 = 0.11\ s^{-1}$ and $k_2 = 50500$ l moles^{-1} s^{-1}[4]. The rates of the two reactions are equal at pH 7.6, at which value the half-life of dissolved carbon dioxide is about 4.5 seconds. Meanwhile, the residence time of the liquid phase in the tube bundles is on the order of one second. Furthermore, because most of the carbon dioxide in the condenser remains in the vapor phase, the concentration of carbon dioxide dissolved in the condensate and thereby available for reaction is small. Because of this, the pH of the surface condenser condensate is determined mostly by the ammonia and hydrogen sulfide in it, while the carbon dioxide and boric acid have only secondary effects.

Carbon dioxide and effectively inert gases like nitrogen and hydrogen also have a secondary effect on the composition of the condensate due to their very presence, in that they lower the temperature and increase the vapor to liquid ratio somewhat.

The condenser modeling code CNDSR. CNDSR is a computer program written in CDC FORTRAN which is used to model the steady state partitioning and transport of gases in the condensers and cooling water loop of a native or flash steam geothermal powerplant[5].

When modeling a surface condenser equipped Unit, one usually models just the condenser and gas ejector system. The cooling water loop may be and usually is modeled separately because its chemistry has no effect upon that of the condenser and ejector system.

CNDSR models gas partitioning and transport in terms of a number of "boxes" which represent the different parts of the system being modeled. For each box, the partition of the gases between the liquid and vapor phases is calculated assuming a thermal and chemical steady state within the box. Specifically, a steady state rate is calculated for the hydration of carbon dioxide in the given box, and all other acid-base reactions and phase relations are modeled as being in full equilibrium. Alternatively, full chemical equilibrium including carbon dioxide hydration may be specified for any given box. Oxidation-reduction reactions are not modeled.

The actual mass fluxes within the condenser are calculated using the steady state results for the individual boxes and the patterns of liquid and vapor flow between the boxes that were specified in the input[6]. The whole procedure is repeated until a global steady state solution is attained.

At present, the following components are included in the chemical and transport models embodied in CNDSR: water, heat, hydrogen sulfide, ammonia, fixed carbon dioxide (i.e., the sum of H_2CO_3, HCO_3^-, and $CO_3^=$), free carbon dioxide (i.e., CO_2 as such), sulfur dioxide, boric acid, oxygen, nitrogen, hydrogen chloride, sulfuric acid, and sodium hydroxide[7].

Neither CNDSR nor any other computer program can reliably predict the liquid and vapor flow fields within the condenser in the detail that is needed in this application. Therefore, the assumed flow fields must be carefully estimated using the condenser manufacturer's plans and specifications, and then finely and repeatedly adjusted to make the calculated results reasonable and consistent with empirical data from existing condensers. This is the key to obtaining correct results using CNDSR.

Normally, the pattern of liquid and vapor fluxes from box to box is set at the start of developing the model, and changed infrequently after that. The rate of conductive heat removal from each box is likewise usually set at the outset and then left alone. The "fine tuning" of the model normally consists of carefully varying the amount of steam flow from the turbine exhaust to each of the boxes. In fact, one is trying to adjust the small "residual" fluxes of vapor that remain after most of the water vapor has been condensed; it is in large measure these gas rich vapor fluxes that determine the gas partitioning performance of the condenser. The enthalpy that these residual vapor fluxes represent is a small fraction of the enthalpy supplied by the main steam flow and then removed by conductive heat transfer; this is why considerable "fine tuning" is needed.

This would be fairly simple if not for the substantial concentration of noncondensible gases in the residual vapor flows. At a given pressure and total enthalpy, increasing the concentration of noncondensibles present causes the temperature to decrease and the amount of water vapor in the vapor phase to increase. Although this effect is, in essence, predictable, such predictions are laborious when executed manually; this introduces a large measure of trial and error into the "fine tuning" process.

A full listing of CNDSR and documentation for it will be published elsewhere. This documentation will include a full discussion of the chemical model and algorithms incorporated in CNDSR, as well as listings of input decks for typical condenser modeling problems, including the ones discussed here[8].

The design and function of Unit 15. Unit 15's main condenser has two essentially identical tubing bundles, only one of which need be modeled.

Figure 1 is a schematized depiction of one of these tubing bundles[9]. The cooling water tubes run down the length of the bundle. There are two cooling water passes. The cooling water flow is countercurrent to the depicted "design vapor flow". There are a number of tube sheets, and these are perpendicular to the cooling water tubes which run through them and are supported by them.

The "vapor channels" on either side of the condenser are defined by rectangular orifices cut in the tube sheets. There are no tubes within the channels. The channels are broken up by small baffles which are approximately the same size as the orifices in the tube sheets, and are mounted in the channels between the tube sheets; that is, the tube sheets and baffles alternate. The function of the baffles is to repeatedly force the vapor flow out of the channel and into the innermost rows of tubes, so as to remove additional moisture from the vapor.

The two vapor channels are connected only at the end of the bundle nearest to the viewer; elsewhere, the two channels are separated by a metal plate which also serves to provide some structural support to the bundle. This support plate is connected to two other plates of U-shaped cross section, one above and one below the vapor channels. The two "U's" are open upward and downward, respectively, and are empty.

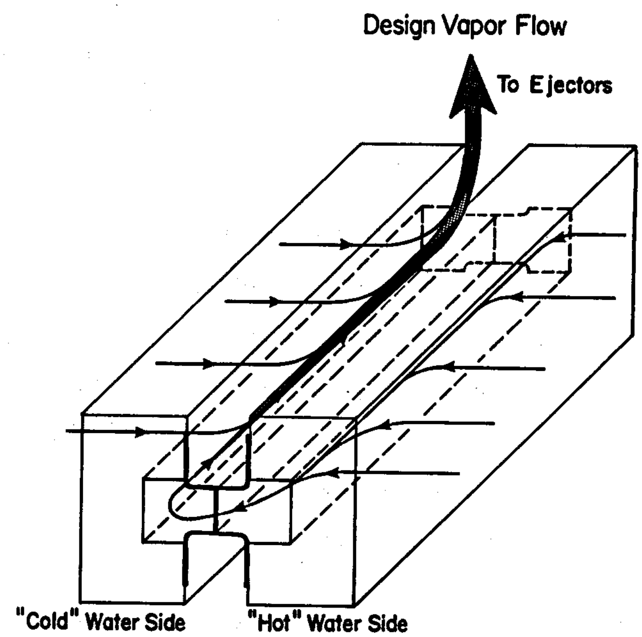


Fig. 1. The vapor flow pattern that the main condenser of Geysers Unit 15 had been designed for. Only one tubing bundle in the main condenser is depicted.

The design vapor flow assumes that the condensing steam will flow radially into the bundle, and that most of the moisture will have condensed out of it by the time that it reaches the vapor channel. The relatively small amount of gas rich vapor that reaches the vapor channel is then expected to flow down the channel, dodging around the baffles as it flows, and picking up additional vapor from each section along the length of the bundle. At the end of the warm pass side of the bundle the vapor flow turns around, and flows back down the cold pass side in the same way. Finally, at the far end of the cold pass side, the vapor is removed from the main condenser by ejector suction by way of a vapor exhaust hood (not depicted).

That the vapor should actually flow like this is implausible, because the baffles that block the channels offer considerable resistance to vapor flow. Instead of evenly drawing vapor out from throughout the bundle, the ejectors will vent only the cold pass side. Meanwhile, relatively cool, gas rich vapor will stagnate on the essentially unvented hot pass side of the bundle, and this will constitute a gas blockage. This combination of unbalanced venting and gas blockage will inevitably increase the fraction of the hydrogen sulfide that dissolves in the condensate.

Table II

Comparison of Modeling Results with Field Data

	Premodification		Postmodification	
	Field	Calculated	Field	Calculated
H_2S in condensate (mmolal)	1.65	1.87	1.47	1.56
NH_3 in condensate (mmolal)	5.29	5.19		7.36
CO_2 in condensate (mmolal)	0.97	0.82		0.74
% total H_2S in condensate	33	39	19	21
Condensate pH	8.5	8.34	8.5	8.64
Turbine backpressure (bar)	0.14	0.136	0.14	0.136
Gross power (MW)	60	--	42	--

These predictions were confirmed. The chemical data are summarized in the first column of Table II. The existence of a gas blockage was directly confirmed by pressure measurements at various points within the vapor flow channel of one bundle. There was found to be no detectable pressure gradient along the channel on the hot pass side of the bundle, indicating little or no vapor flow along it. There was actually a shallow pressure minimum on the cold pass side, near the turn-around point. The existence of this minimum completely excluded the possibility that the vapor flow was obeying the design pattern.

The conceptual model of the vapor flow pattern that was ultimately arrived at on the basis of field data and modeling studies is depicted in Figure 2. The vapor flow on either side of the bundle is in the same direction: toward the vapor exhaust hood. Because the vapor exhaust hood vents only (one end of) the cold pass, the vapor from the hot pass side must somehow be vented over to the cold pass side. The only possible path for it is to cross over underneath the bundle and then go up into the vapor channel on the cold pass side. This much was established from consideration of the vapor pressure data and design drawings alone.

The modeling studies established what proved to be the key to successfully retrofitting the condenser and substantially improving its hydrogen sulfide performance. Apparently, the flow resistance along the vapor channels is so large relative to the resistance to radial flow through the bundle that very little vapor is actually vented from most of the bundle; perforce, this small amount of vapor is very gassy because it carries with it most of the noncondensible gases that accumulate in the bundle as the steam condenses. Thus, not only the hot pass side of the bundle is vapor blocked, but most of the cold pass side appears to be as well. Apparently, most of the ejector capacity is satiated by drawing vapor with a much lower gas content out of just that small part of the bundle that is immediately adjacent to the vapor exhaust hood. The poorly vented part of the bundle has poor heat transfer, and the condensate falling out of it contains a substantial concentration of hydrogen sulfide.

The gas ejectors are of the usual steam jet type. The inter- and aftercondensers are small surface condensers of the tube-and-shell type. The hydrogen sulfide partitioning performance

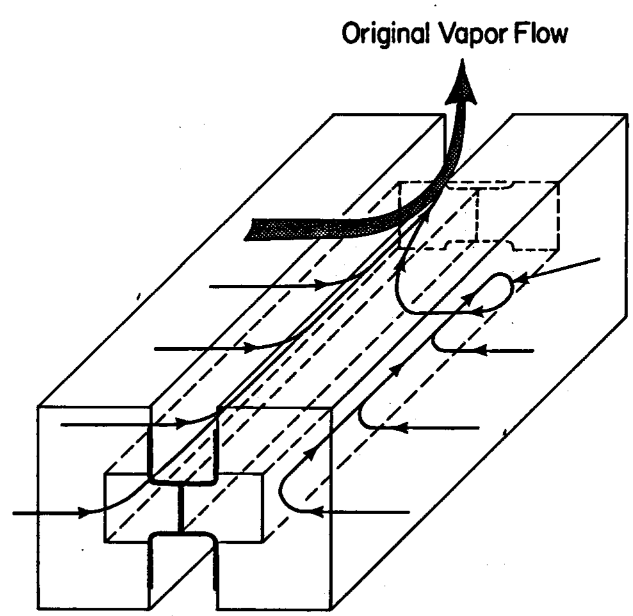
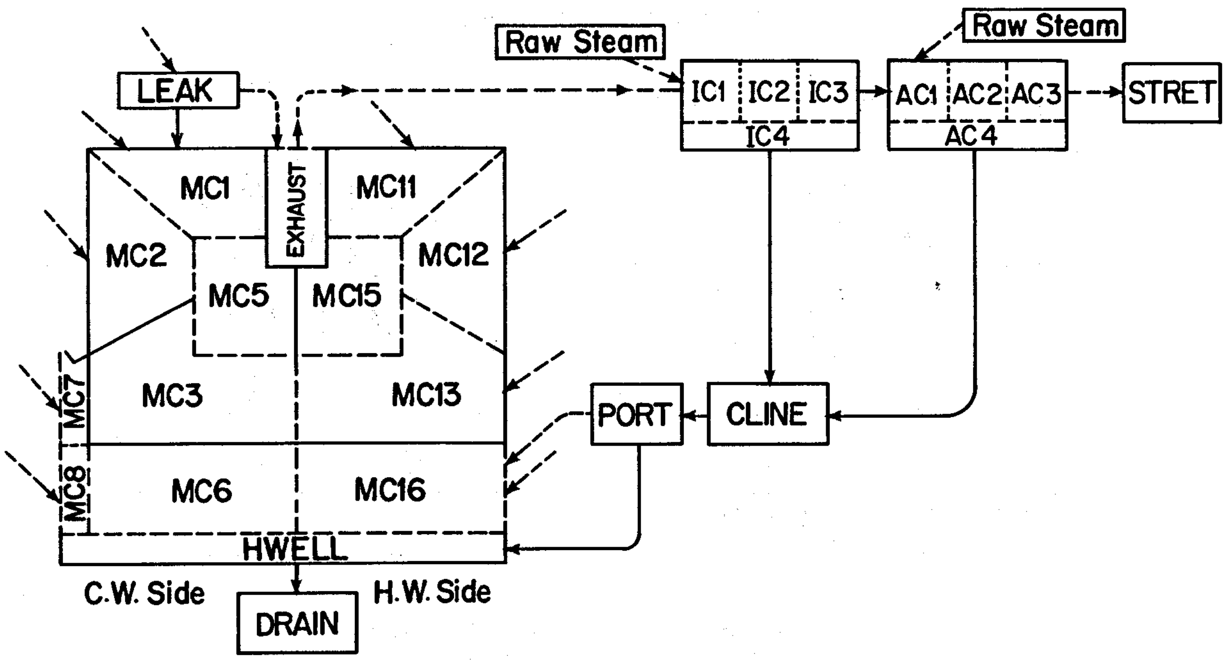


Fig. 2. The actual vapor flow pattern in a tubing bundle before the condenser was modified, as inferred from field data and modeling studies.



Model of Geysers Unit 15

Fig. 3. Short dashed arrows represent steam flow from the turbine exhaust into the main condenser bundle. "Raw Steam" represents the motive steam supply to the gas ejectors.

of a powerplant that is predicted or is actually observed is not particularly sensitive to the exact configurations of these components, and they need not be described any further. The condensate drips from the inter- and after-condensers are discharged into the main condenser cavity through a port in its side.

The model. The computer model developed for Unit 15 is depicted in Figure 3. The main condenser is represented by a single cross section of one bundle; this is adequate, because there is probably little longitudinal variation in chemical conditions along most of its length. That most of the ejector capacity is in effect wasted is modeled by putting into the model a "LEAK" that permits steam to go directly from the turbine exhaust to the vapor exhaust hood.

This condenser design includes a "reheating hotwell". Part of the steam that flows into the bottom part of the bundle (represented by boxes MC3 and MC13 in the model) flows into the bundle from underneath; that is, by way of boxes MC6 and MC16. This steam contacts and partially reheats and steam strips the condensate falling out of boxes MC3 and MC13. On the cold pass side of the bundle only, there is a condensate deflector plate which causes the condensate formed above it to flow to the periphery of the bundle and fall into the hotwell from there. In boxes MC7 and MC8 this portion of the condensate contacts the steam flowing to boxes MC3 and MC6, and is partially reheated and steam stripped by it.

The gas ejectors need not be explicitly included in the model because, for our purposes, they merely serve to mix motive steam with the vapor being ejected. Therefore, it is sufficient to depict only the inter- and after-condensers with the motive steam flowing directly into them along with the vapor being ejected. Each of these small condensers has one vapor pass, and is adequately represented by three boxes which represent the bundle plus a fourth which represents the drain.

CLINE represents the condensate return line, and PORT represents the point at which the return line enters the main condenser. Because the main condenser is at lower pressure than the other two, the condensate flashes and separates into two phases in PORT.

The two "output boxes" in this model are DRAIN, which represents the main condenser drain, and STRET, which represents the Stretford Unit. The major result of the calculation is the partition of hydrogen sulfide between STRET and DRAIN.

In the various condensers, only the steam side of the heat exchange tubes needs be included in the model. The cooling water side of the heat exchange tubes is represented as simply a heat sink in the given box.

For the most part, the condensate flowing out of any given box is modeled as flowing into the box directly beneath it. The condensate flowing out of MC1 is divided between MC2 and MC5,

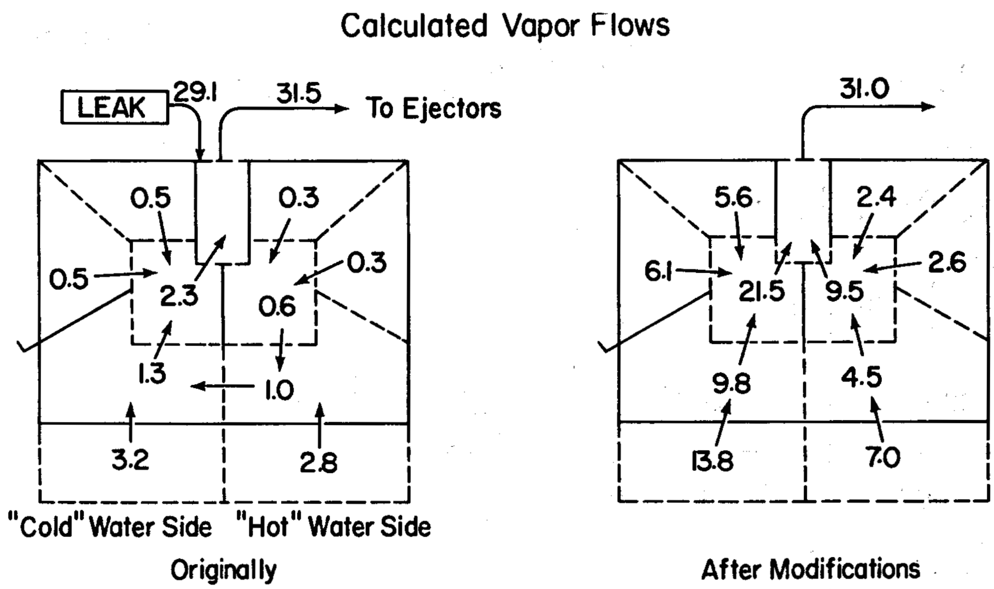


Fig. 4. All mass fluxes given in terms of grams of water vapor per second. Given the scale of the model, this is the same as grams of water vapor per kilogram of water in the turbine exhaust. Noncondensibles are understood to flow along with the water vapor.

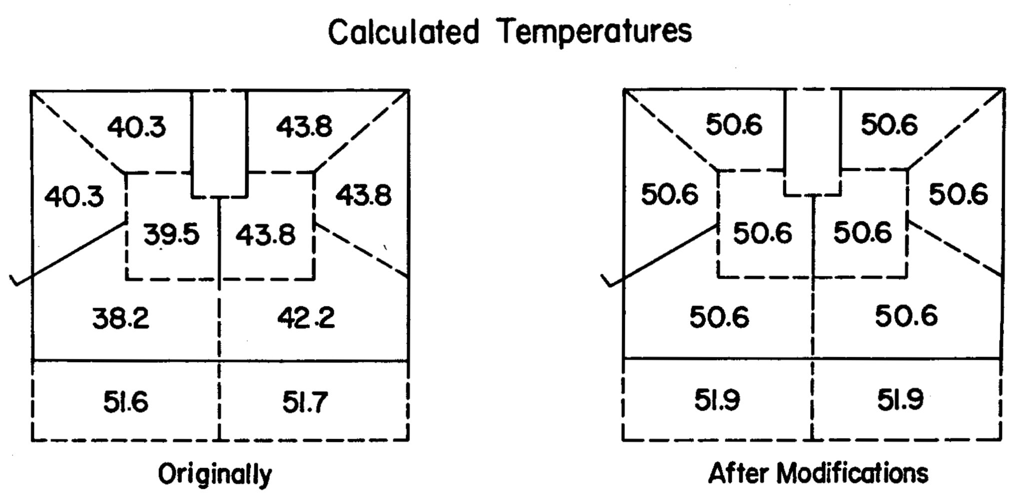


Fig. 5. Temperatures in degrees Celsius.

and the case with MC11 is similar. The effect of the condensate deflector plate is represented by having the condensate that flows out of MC2 flow into MC7. The pattern of vapor flows is depicted in Figure 4.

Those values from the design mass and heat balance of the Unit that were incorporated in the model are summarized in Table III. The model is scaled to 1 kg/s steam flow from the turbine exhaust. (The design turbine steam flow is 134.7 kg/s.)

It was hard to make the fraction of the hydrogen sulfide dissolved in the condensate in the model as large as it was known to be in the actual powerplant. Within the limits set by physical plausibility and the requirement of consistency with the design mass balance and the available field data, everything possible had to be done to the model to make its hydrogen sulfide partitioning performance as poor as that of the actual powerplant. Thus, in a practical sense, modeling the chemical perform-

Table III

Specifications for the Geysers Unit 15 Model

Condenser pressures (bars absolute):	
Main condenser:	0.136
Intercondenser:	0.320
Aftercondenser:	1.000
Steam flow from turbine:	
Rate (g H_2O/s):	1000
Enthalpy (kj/kg H_2O):	2317
Motive steam to gas ejectors (g H_2O/s):	
1st stage:	32.15
2nd stage:	21.90
Enthalpy (kj/kg H_2O):	2679
Vapor flows between components (g H_2O/s):	
Main condenser --> Intercondenser:	31.5
Intercondenser --> Aftercondenser:	0.8
Aftercondenser --> Stretford Unit:	0.5
Heat removal by cooling water (kj/s):	
Main condenser:	2031
Intercondenser (premod.):	152.7
Intercondenser (postmod.):	151.2
Aftercondenser:	53.7

The values in this table were derived from the design mass and heat balances provided to us by PG&E.

ance of Unit 15 turned into an extremum problem. This circumstance increases our confidence in the model that resulted.

Ultimately, the observed hydrogen sulfide partitioning and other field data were matched using three major physical assumptions:

1) The vapor flow pattern is, in essence, that depicted in Figure 2,
2) Most of the vapor that the gas ejectors eject from the main condenser comes by way of "the LEAK", instead of being evenly vented from the whole bundle, and
3) There is only partial contact between liquid and vapor in boxes MC6, 7, 8 and 16, with consequently poor steam stripping of the condensate.

Assumption 3) is reasonable. In the actual condenser the zone that corresponds to boxes MC6 and 16 in the model is only about one-quarter of a meter in vertical extent. The condensate that flows off the deflector plate does so through fairly large holes, very probably in compact streams. Therefore, the falling condensate does not have the opportunity to be optimally steam stripped before it reaches the hotwell.

In the terminology of chemical engineering, the extent of steam stripping of the condensate in boxes MC6, 7, 8, and 16 is less than a single plate per box. Ultimately, the extent of steam stripping in these boxes was modeled as 0.083, 0.022, 0.024, and 0.095 plates, respectively[10].

The pattern of "residual vapor flows" within the main condenser that was finally arrived at is depicted on the left of Figure 4. The total amount of vapor that is ejected from the main condenser (31.5 g/s) was adjusted to approximately match the design heat and mass balance for the Unit (Table III). The division of this amount between LEAK and the tubing bundle proper was arrived at in matching the empirical hydrogen sulfide partitioning performance of the Unit. The small residual vapor flows from MC6 and 16 up to MC3 and 13, respectively, are the result of the small fractional plates of steam stripping assumed for boxes MC6, 8 and 16. These too were arrived at in matching the actual performance of the Unit.

These two effects may be traded off against each other in striving to match the empirical data. The balance between them was ultimately determined by the need to have a physically reasonable temperature distribution within the bundle (left side of Figure 5). At various points in the model development process and at its end fine adjustments were made to make the patterns of vapor flow and temperature smooth and physically reasonable[11].

The actual number and arrangement of boxes used in the model could also have been varied in matching the empirical data, but were not. The "mesh" that represents the main condenser is so coarse that it could not have reasonably been made any coarser. To have made it finer by using smaller boxes and more of them would have tended to decrease the concentration of hydrogen sulfide in the condensate.

Physically, the large size of the boxes probably means that a flowpath whose length is comparable to the radial extent of the boxes within the bundle is needed to achieve full contact between the incoming steam and the condensate falling from above. In other words, each of the boxes within the bundle corresponds to approximately one plate of liquid-vapor contact.

The temperatures calculated within the tube bundle are low (Figure 5), and the calculated concentrations of noncondensibles are correspondingly high. On the hot water side of the bundle the noncondensibles constitute about one-third of the vapor phase on a mole basis, while on the cold water side they constitute one-half of the vapor phase. This situation is quite adequate to explain the poor thermal performance of the Unit; the heat exchange area in this condenser was oversized by 30% to allow for tube fouling, but it just barely performed up to specifications with clean tubes.

The calculated concentration of bicarbonate in the condensate reflects mostly the value assumed for the residence time of the liquid phase in each of the boxes. The residence time values used were: 2.5 seconds in each of MC1, 2, 3, 11, 12 and 13, 0.2 s in MC5 and 15, 0.3 s in MC6, 7, 8 and 16, 2.0 s in IC1, 2 and 3 and CLINE, and 1.0 s in AC1, 2 and 3. These values were determined using the actual physical dimensions of the various components to estimate how long it would take the condensate to fall through them, etc.

Results and practical recommendations. The first column in Table II presents the essential data about the chemical performance of Geysers Unit 15, as determined from the first mass balance established soon after it went on line[12]. At that time the steam composition was approximately that presented in the first two columns of Table I. This is the body of data to which the model was fitted[13].

The second column in Table II presents the model's output. The only significant discrepancy is that the model shows a slightly higher fraction of the hydrogen sulfide partitioning into the condensate than is actually observed. This discrepancy was due primarily to the use of inconsistent data (not shown) at one point in developing the model[14].

It turned out that the condenser could be physically modified to correct the problem of poor venting. The essence of this modification is shown in Figure 6. Basically, the U-shaped channel on the top of the bundle was covered with a welded metal plate to make it an enclosed vapor removal duct. Venting of each section of the tube bundle into the duct is provided by properly sized holes drilled through the floor of the duct into each section on either side of the bundle. The newly formed duct is vented to the vapor exhaust hood at one end, while the original vapor flow channel is blocked off from the hood.

The idea of this modification is to force properly balanced venting of all sections of the tube bundle[15]. Ideally, the amount of vapor vented from each section in the bundle should be proportional to the amount of steam that condenses within that section. In this case, the partial pressure of noncondensibles in the vapor, the temperature, and the vapor to liquid ratio would be the same in each section of the bundle.

The key to accomplishing this is to size the vent holes in the bottom of the vapor duct appropriately. A first order engineering calculation suggests that the sum of the areas of the holes in the duct should be equal to the cross-section of the duct, and that the sum of the areas of the holes venting any one section should be proportional to the amount of steam that condenses in that section; that amount may be estimated by performing routine heat transfer calculations. Extreme accuracy in sizing the holes is actually not required because the overall performance of the condenser is not very sensitive to this within reasonable limits[16].

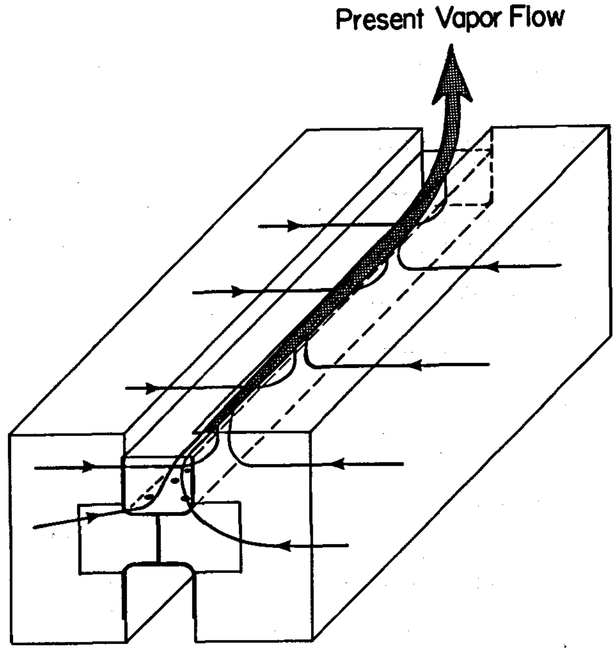


Fig. 6. The vapor flow pattern in a tubing bundle after the condenser had been modified as discussed in the text.

This modification was originally proposed by G.W. Allen, who was then with the PG&E Department of Engineering Research. It was evaluated by LBL using the numerical model of Unit 15 described above, correspondingly modified for this purpose.

Essentially, the modifications in the model consisted of eliminating the LEAK, changing the vapor flow pattern inside the main condenser tube bundle to that shown on the right side in Figure 4, and rebalancing the steam flow into the bundle to give a uniform temperature throughout the bundle. Neither the vapor flow pattern underneath the bundle (MC6, 7, 8, and 16), nor the number of plates of reheating in these boxes was changed. The resulting vapor flow and temperature fields are shown on the right in Figures 4 and 5.

These calculations indicated that modifying the condenser in this way would lead to a substantial improvement in its hydrogen sulfide partitioning performance. Based on these calculations, the decision was made by PG&E to proceed with the modifications. The modifications were engineered by J. Laszlo of PG&E's Mechanical

Engineering Department, with assistance from L. Forster of the Ecolaire Company. They were implemented during the annual overhaul shutdown in September of 1980.

Unfortunately, over the time of the shutdown the composition of the steam supply to Unit 15 changed (Table I, columns 3 and 4), and the amount of available steam flow dropped. When Unit 15 went back on line, it did so with a gross power output of about 42 MW, and the change in steam composition made it hard to compare its performance in its modified form to what it had been before.

Finally, several months after it went back on line adequate chemical data had been gathered to allow the effect of the modifications to be assessed. It appears that they worked. Although the steam concentrations of hydrogen sulfide and ammonia had both increased by about half, the concentration of hydrogen sulfide in the condensate had actually decreased by a small amount (compare Table II columns 1 and 3). However, there had been a substantial decrease in the fraction of the hydrogen sulfide in the condensate.

Calculations were then performed using exactly the same postmodification model, but with the new steam composition. The results of these calculations are summarized in column 4 of Table III. The agreement is, overall, good.

There are two known inaccuracies in the calculation, whose effect may be estimated and corrected for. First, the premodification model is known to be pessimistic, and this error probably was carried over into the postmodification model. Therefore, the latter is probably pessimistic by about the same factor. Second, it turned out that the holes that had actually been drilled through the floor of the new vapor removal duct had not been optimally sized. In effect, the sections on the hot water side were vented too much while the sections on the cold water side were vented too little. In our estimation, the effect of this was to increase the amount of hydrogen sulfide in the condensate by about 9%. Adjusting the calculated figures for these effects leads to a predicted concentration of hydrogen sulfide in the condensate of 1.44 millimolal which is within analytical error of that actually observed.

It is possible to estimate the economic consequences of the modification. Using the premodification model, we estimate that, had the Unit not been modified while the steam composition changed as it did, the concentration of hydrogen sulfide in the condensate would have been about 101 ppmw after the annual overhaul. Correcting this figure for the known pessimism of the model, we obtain a revised estimate of about 85 ppmw. Therefore, the modification succeeded in reducing the hydrogen sulfide concentration in the condensate by about 35 ppmw.

Unit 15 is presently operated with tertiary abatement by hydrogen peroxide. The hydrogen peroxide is used at a rate of approximately 1.5 moles per mole of hydrogen sulfide dissolved in the condensate; because their molecular weights are equal, this means 1.5 pounds of hydrogen peroxide per pound of hydrogen sulfide as well. The price of 50% hydrogen peroxide is about \$0.25/lb, and the current steam supply to Unit 15 is about 770,000 lb/hour. Combining these figures, we estimate that the savings realized by the modifications amount to \$20.20/hour = \$485/day.

Within normal limits, changes of Unit load and turbine backpressure seem to have had no effect on hydrogen sulfide partitioning. It is possible that the modifications increased the operating backpressure somewhat; reducing the gross load by 18 MW ought to have caused the backpressure to decrease, but no such decrease was observed when the Unit went back on line.

The effect of varying steam chemistry. As has been noted repeatedly, the hydrogen sulfide partitioning in a condenser varies with the composition of the steam. Therefore, one cannot assign a "partitioning value" to a given condenser design; however, one may predict its partitioning performance for a given steam composition, or even define a "response surface" which describes the partitioning, etc., as a function of steam composition.

Figure 7 depicts the concentration of hydrogen sulfide in the condensate as a function of the hydrogen sulfide and ammonia concentrations in the steam. The effect of varying steam hydrogen sulfide is remarkably small except at the lower hydrogen sulfide concentrations. The effect of varying the ammonia concentration is larger. Figure 7 may be used to predict the effect of further changes of steam composition upon the concentration of hydrogen sulfide in the condensate.

Figure 8 depicts the percentage of hydrogen sulfide dissolved in the condensate as a function of the mole ratio of ammonia to hydrogen sulfide in the steam. Although the correlation is not perfect, it is obvious, and it is the strongest that was found.

Calculations were also performed for the case of steam compositions which are similar to those in Table I except that they contain no ammonia. In this case, the premodification model predicted 0.2% of the hydrogen sulfide in the condensate, while the postmodification model predicted less than 0.03% of the hydrogen sulfide in the condensate. In other words, if there is no ammonia in the steam, a surface condenser will give virtually no hydrogen sulfide in the condensate, regardless of design, vapor venting pattern, etc.

In general, once a model has been set up, it may be used to predict hydrogen sulfide partitioning, pH, etc., over a broad range of steam

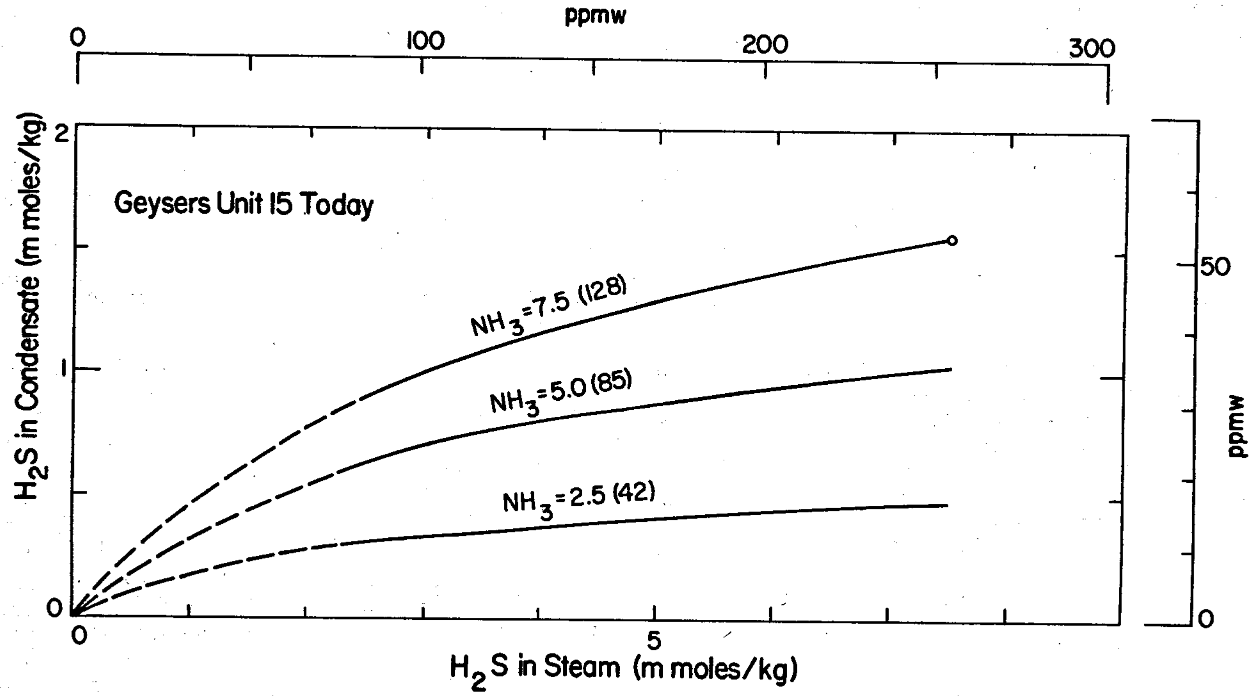


Fig. 7. Condensate hydrogen sulfide concentrations for Unit 15 as a function of steam composition, calculated using the postmodification model. ppmw = part per million by weight. mmoles/kg = mg-moles/kg. Ammonia concentrations given in mmoles/kg and ppmw.

compositions. The only restriction is that the total concentration of noncondensibles in the steam (excluding ammonia from the sum) should not be much different from that in the steam composition for which the model was initially set up[17].

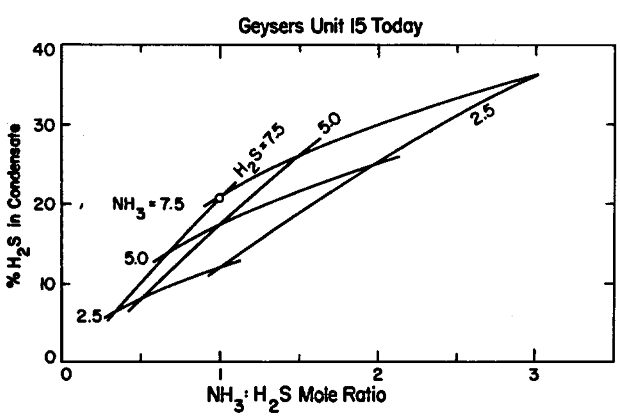


Fig. 8. This is a replot of Fig. 7.

<u>Summary and discussion</u>. The geothermal condenser modeling code CNDSR has been successfully applied to modeling Geysers Unit 15. This modeling work led to practical recommendations for modifying this Unit's main condenser to improve its hydrogen sulfide partitioning performance. These recommendations were implemented, and they worked.

The model of Unit 15 was developed and refined by adjusting it to match the actual hydrogen sulfide partitioning performance of Unit 15 as determined in the field. In retrospect, it is clear that this Unit's performance could not actually have been predicted in advance. However, it was possible to accurately predict the effect of the modifications, because the postmodification model was really an extrapolation of the premodification model. In particular, that portion of the model which describes the extent of condensate reheating by steam below the bundle was taken over from the premodification model unchanged.

The accuracy with which the hydrogen sulfide partitioning performance of a given condenser design may be predicted ahead of time will vary with the details of that design. In particular, a design which forces a relatively well balanced and well defined pattern of vapor venting from the bundle would be much easier to evaluate. However, even in this case it is difficult to predict to what extent the condensate is reheated by the incoming steam. The best that can be done is to estimate the number of plates of reheating by drawing on past experience.

The partitioning of hydrogen sulfide is affected by the overall steam chemistry; in particular, by the ratio of ammonia to hydrogen sulfide in the steam. Therefore, meaningful calculations cannot be made unless at least the correct hydrogen sulfide and ammonia concentrations in the steam are known by the modeler. A condenser model may best be considered a response function which calculates the concentration of hydrogen sulfide in the condensate, etc., as a function of steam composition.

Because the composition of the steam supply to Unit 15 changed during the time that it was being overhauled and modified, the actual concentration of hydrogen sulfide in the condensate that was measured after the modifications was not the same as had been predicted. However, putting the new steam chemistry into the "after modification" model did result in calculated figures which matched the new field data quite well. In other words, the "response function" that had been predicted for the modified Unit was correct.

Modeling the chemical characteristics of the condenser also led to an improved understanding of mass transport and heat transfer within it. In a sense, the pattern of vapor flow and its interaction with the liquid phase were elucidated by analyzing the results of a tracer experiment.

Acknowledgements. This work was supported by the Department of Engineering Research of the Pacific Gas and Electric Company under Contract 5-50-78, and by the Division of Geothermal Energy of the U.S. Department of Energy under Contract W-7405-ENG-48.

All of the design information and field data quoted in this report were provided to LBL by PG&E and the Ecolaire Company. In particular, the author wishes to acknowledge the assistance of G.W. Allen and S.G. Sharp of the PG&E Department of Engineering Research, J. Laszlo of the PG&E Department of Mechanical Engineering, and L. Forster of the Ecolaire Company.

NOTES:

[1] Geysers Units 13 and 14 are equipped with surface condensers of the same kind, but they went on line after Unit 15.

[2] Weres, O., Tsao, K., and Wood, B., "Resource, Technology and Environment at The Geysers". Report LBL-5231. Lawrence Berkeley Laboratory, Berkeley, CA. July 1977. Sections 11.6 and 7. (This and other LBL reports are available from the National Technical Information Service.)

[3] Reports in preparation.

[4] The formulas used in our code to calculate these rate constants and their inverses are taken from: Pinsent, B.R.W., Pearson, L., and Roughton, F.J.W., "The Kinetics of Combination of Carbon Dioxide with Hydroxide Ions", Trans. Faraday Soc., 52 , 1512 (1956); and Sirs, J.A., "Electrometric Stopped Flow Measurements of Rapid Reactions in Solution: Part 2. - Glass Electrode pH Measurements", Trans. Faraday Soc., 54 , 207 (1958).

[5] Other sources of chemical data included in CNDSR's data base include Edwards, T.J., Newman, J., and Prausnitz, J.M., "Thermodynamics of Aqueous Solutions Containing Volatile Weak Electrolytes", AIChE J., 21 , 248 (1975); Helgeson, H.C., "Thermodynamics of Complex Dissociation in Aqueous Solution at Elevated Temperatures", J. Phys. Chem., 71 , 3121 (1967); Mesmer, R.E., Baes, C.F., Jr., and Sweeton, F.H., "Acidity Measurements at Elevated Temperatures. VI. Boric Acid Equilibria", Inorg. Chem., 11 , 537 (1972); Truesdell, A.H., and Jones, B.F., "WATEQ, A Computer Program for Calculating Chemical Equilibria of Natural Waters", J. Research U.S. Geol. Survey, 2 , 233 (1974); International Critical Tables, Vol. III, pp. 256-7; Eisenberg, D., and Kauzmann, W., The Structure and Properties of Water , Oxford University Press (New York and Oxford, 1969), pp. 182-191; and Fisher, J.R., "The Ion-Product Constant of Water to 350°C", Thesis, The Pennsylvania State University, Department of Geochemistry and Mineralogy, June 1969.

[6] The pattern of liquid and vapor flows is specified in the sense of "the liquid flux out of box A goes to box B, while the vapor flux out of box A goes to box C"; the actual flowrate of liquid or vapor from box A to box B

or C is calculated. Either flux out of a given box may be split as desired between up to eight other boxes as well.

[7] In modeling, "nitrogen" normally represents the sum of nitrogen, argon, methane, and hydrogen. All of these gases are practically inert inside of the condenser, and the only effects they have arise from the fact of their physical presence.

[8] Report in preparation.

[9] Details that are not immediately relevant to the present purpose have been left out to protect the manufacturer's proprietery interests.

[10] Steam stripping within a given box by less than a full plate is modeled by having part of the steam flowing through it "bypass it". Consider box MC7, which was modeled with the assumption of 0.022 plates of steam stripping: about half of the steam that condenses in MC3 may reasonably be assumed to reach MC3 by way of MC7. If MC7 stripped by a full plate, 50% of the amount of steam that condenses in MC3 would be modeled as flowing from the turbine exhaust into MC7, and then out of MC7 into MC3. Stripping by 0.022 plate is represented by having only 50% x 0.022 = 1.1% of the steam flow into MC7, while the remaining 48.9% flows directly into MC3.

[11] All of these adjustments were made by carefully and finely varying the fluxes of steam from the turbine exhaust into the various boxes in the bundle. Occasionally, the rate of heat removal from the main condenser, the intercondenser, or the aftercondenser had to be adjusted to make the vapor flows between the condensers match the design mass balance. In such cases, the residual vapor flows inside the main condenser usually had to be rebalanced.

[12] Quoted from an internal PG&E memo which was provided to LBL as a private communication.

[13] Other, more complete mass balance data have become available since, but this happened too late for it to be used in this work. This additional data is presented in: Henderson, J.M., Ku, W.P.C., and Thoma, A.L., "Material Balance, Unit 15, The Geysers Power Plant". PG&E Department of Engineering Research Report 411-80.12. San Ramon, CA. May 15, 1980.

[14] This is a recurrent problem in this sort of work. A basic problem is that the composition of the steam changes with time. Therefore, one cannot combine, say, a steam hydrogen sulfide concentration value determined one month with a condensate concentration value measured the next. Ideally, one should work with only one self-consistent mass balance based on measurements performed over no more than a few days time.

[15] This principle of balanced venting into a vapor duct that runs the length of the tube bundle is incorporated in the design of the condensers that will be used in Units 16 and beyond.

[16] When hydrogen sulfide dissolves in the condensate mainly as ammonium bisulfide, its partition between vapor and liquid varies approximately in proportion to the square root of the volume ratio of vapor to liquid.

[17] This is more a mathematical idiosyncracy of the model than a physical characteristic of the system being modeled. Changing the concentration of noncondensibles would perturb the calculated temperature and vapor flow fields in a nonphysical way, and require the steam flows into the bundle to be "rebalanced". Therefore, when changing the steam composition, one adjusts the actual new composition to be tested to match the total concentration of noncondensibles in the steam composition that was originally used. This is best done by changing the concentration of nitrogen in the steam. Models of well vented condensers are less sensitive to total gas loading than those of poorly vented condensers. Models of contact condenser powerplants are relatively insensitive to it.

GROWTH OF HOT DRY ROCK RESERVOIRS

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Since its creation in 1977, the hot dry rock geothermal reservoir at Fenton Hill, New Mexico, has been extended in size and heat production capacity by an order of magnitude. This growth was accomplished without redrilling of either the injection or the production well, and is attributed to both pressurization and thermal contraction cracking of the surrounding reservoir rock. Tracer injection tests over the four years of intermittent operation have shown that the reservoir void volume has increased by more than a factor of 20, from 11 to 260 m^3. Since this void volume is due to thin, nearly closed fractures in otherwise nonporous rocks, a significant increase in the number of fractures and fracture area is indicated. This is confirmed by heat transfer modeling of heat production and thermal drawdown results. Actually, two models have evolved, and while the derived results differ in detail, gross reservoir properties such as active heat transfer area are in reasonable agreement. Both models indicate that this heat transfer area has grown from 10,000 to 70,000 m^2. Despite this reservoir growth other reservoir properties, which might have been expected to keep pace, fortunately did not. For example, water losses caused by diffusion of water through the fracture network to the surrounding rock increased by only 30 percent, despite a 6-fold increase in heat transfer area. In addition, the hydraulic resistance or impedance of the reservoir remained nearly constant--apparently the longer flow paths corresponding to fracture growth were compensated by opening of the fractures.

EPRI GEOTHERMAL PROJECTS OVERVIEW: POWER CONVERSION AND NONCONDENSABLE GAS CONTROL

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Introduction The EPRI Geothermal Power Systems Program is part of the effort by the electric utility industry directed at realizing certain advantages offered by geothermal power generation. The principal reasons for utility interest in geothermal resources as a source of new electrical generating capacity arise from the following characteristics of geothermal power systems:

- Based on a domestic energy resource;
- No emissions of combustion air pollutants;
- No nuclear radiation accident risks;
- Compatible with expansion by small increments;
- Technology available now and deployed in several countries.

The actual, physical characteristics of geothermal energy resources give geothermal power systems certain unique features relative to other sources of energy available to the electric power industry. Three of these unique features of geothermal power production are noteworthy because they give rise to the major problems being addressed by the EPRI geothermal research program:

- Low temperature resource
- Dissolved minerals and gases
- Dependence of each power plant on a single geothermal reservoir as its source of "fuel".

In what follows I will elaborate briefly on each of these features of geothermal power production and will indicate how the EPRI geothermal power has addressed the problems associated with these natural features. Finally, I will mention some specific results of EPRI research directed toward solving these problems.

Problems and Program Content Geothermal resources that occur close enough to the surface of the earth to be potentially useful in meeting human energy needs are always of lower temperature than the temperatures we choose to work with when we can burn a fuel to produce heat for power generation. The thermodynamic consequence of a lower temperature coming into a power conversion system is lower efficiency: less production of useful work (or electricity) from the heat (or enthalpy) that is the source of energy for the system. The substantial cost of the exploration, drilling, well construction and other activities needed to produce geothermal fluid from a reservoir make fuel cost a significant factor, even though geothermal fluid is not as efficient a producer of power as a fluid heated by combustion. Therefore, achieving a high level of resource utilization is important to making geothermal an economically viable source of power generation. (Resource utilization is measured in watt-hours of electricity produced per kg of geothermal fluid supplied to the power plant.)

To improve the power output per unit of flow of geothermal fluid into the conversion system, EPRI has placed major emphasis on binary cycle geothermal power plants. Projects directed at the binary cycle technology have included component testing and power system design. In addition, the EPRI geothermal program has focused on development of one advanced power conversion system that can increase the resource utilization in direct flash power plants. This is the rotary separator turbine (RST) power system.

Another consequence, and problem, arising from the relatively low temperature of available geothermal fluids is the need to reject more heat per unit of electricity produced than would be rejected from a combustion plant generating the same amount of electricity. This problem is intensified by the relative scarcity of water for power plant cooling in many geothermal resource areas of the United States. EPRI has addressed the problem through an analysis of wet/dry cooling systems, showing that appreciable reduction in cooling water requirements is possible at a cost penalty that is high in hot desert areas like the Imperial Valley but modest in moderate or cool climate regions.

The dissolved mineral and gas content of naturally occurring geothermal fluids produces the problems of scaling and corrosion and the problem of H_2S emissions. In addition the total noncondensable gas content has consequences for net power plant efficiency, due to the parasitic power requirements imposed by the need to remove gases from the condenser. To address the scaling and corrosion problems, EPRI has conducted studies of brine chemistry and has developed computer codes to simulate scale and corrosion in geothermal power systems. A mobile chemical analysis laboratory has been built and is in use to develop a data base on geothermal chemistry and to provide on-site chemical sampling and analysis capability for geothermal power plants and field test projects.

Elimination of the environmental problems associated with H_2S emissions (primarily an odor nuisance problem) and alleviating the corrosion potential carried by acid gases in geothermal fluids are the objectives of current EPRI projects to test upstream removal of non-condensable gases. These projects involve laboratory measurements of H_2S removal by copper sulfate scrubbing and field measurements of noncondensable gas removal by upstream reboiling.

The direct reliance of a geothermal power plant on the production of energy from a specific reservoir gives rise to problems affecting both decisions on whether to build a geothermal plant and choices of plant design, construction and operation. The EPRI geothermal binary cycle projects have included optimization studies that take into account changes in reservoir production over the life of such a plant. Resource and reservoir studies have been included in the EPRI geothermal program, although the major efforts of the program are concerned with resource use rather than resource production.

Figure 1 presents a matrix summarizing the EPRI Geothermal Power Systems Program in terms of the characteristics, problems and program responses discussed above.

Economics and Resulting Implications for Program Content Some general conclusions regarding the economics of geothermal power generation have influenced the design of the EPRI program. I will summarize these conclusions in order to make explicit some of the rationale behind program and project objectives.

Flashed steam or binary cycle power conversion systems are the technologies for use with the hot water (as opposed to dry steam) geothermal resources. (Dry steam resources are economically very attractive, but are too rare to be considered by most utilities.) Both of these technologies for the hydrothermal resources are expected to have the following economic characteristics:

- Costs very dependent on "fuel" supply parameters
  - temperature
  - well cost
  - well production rate.
- Usually lower busbar electricity cost than oil-fired power plants.
- Sometimes competitive with coal and nuclear.
- Fuel cost (geothermal fluid supply cost) is a major factor, about half the busbar electricity cost.

These and other considerations lead to the following conclusions regarding the major ways to reduce the cost of geothermal power:

CHARACTERISTIC	PROBLEM	PROGRAM RESPONSE
RELATIVELY LOW TEMPERATURE OF RESOURCE	LOW POWER OUT PER UNIT OF FLOW IN	• BINARY CYCLE DEVELOPMENT • ADVANCED CONV. TECH. DEV.
	HIGH HEAT REJECTION REQ.	• WET/DRY COOLING STUDY
DISSOLVED MINERALS AND GASES IN FLUIDS	SCALING AND CORROSION	• BRINE CHEMISTRY STUDIES • COMPUTER SIMULATION • MOBILE CHEMISTRY LABORATORY
	HYDROGEN SULFIDE EMISSIONS	• UPSTREAM ABATEMENT TESTS
PLANT/RESERVOIR LINK	RESERVOIR RISK IN PLANT DECISIONS	• BINARY DESIGN OPTIMIZATION • RESOURCE/RESERVOIR STUDIES

Figure 1 -- EPRI Geothermal Program: Response to Problems Confronting Geothermal Power Development

- Achieve high reliability and capacity factor; this is the objective of the scale control and other chemistry-related projects.

- Reduce geothermal fluid production costs; this is primarily a resource company issue, but is also a motivating factor for EPRI projects on reservoir and resource topics.

- Increase resource utilization efficiency: more kWh per kg of brine produced; this is a key objective of the advanced conversion technology projects.

Highlights I will highlight results from three areas of the EPRI geothermal program. These are binary cycle power systems, advanced conversion concepts and upstream removal of noncondensable gases. The other paper in this section, by Meredith Angwin of EPRI, highlights projects involving geothermal chemistry and geopressured resource utilization.

Binary Cycle Power Plant Development The objective of the major EPRI effort on binary cycle power plant development is to extend the range of economic geothermal power generation to lower temperature hydrothermal resources. Primary results from the EPRI projects in this area are as follows:

- Binary cycle resource utilization efficiency (Wh/kg) can be over 1/3 better than 2-stage flash

- Fouling of heat exchangers exposed to Heber brine will not be excessive

- Brine to isobutane heat transfer can be adequately estimated using standard values and methods

- Hydrocarbon turbine (axial flow or radial in-flow) can be supplied for 65 MWe (gross) binary plant with minimal change from existing equipment

- Optimized preliminary design binary plant at Heber is complete (65 MWe gross, 45 MWe net)

Contractors who have performed the work on these projects include: Holt/Procon, San Diego Gas and Electric, Fluor, Ben Holt, Colley, Schilling, PFR Engineering, Elliott, and Rotoflow.

Advanced Power Conversion Concepts The objective of the EPRI projects on advanced geothermal power conversion concepts is to increase the Wh/kg efficiency with systems having acceptable capital cost and good reliability. Principal results in this area include the following:

- Designed, built and tested 30-inch, 20 kWe experimental rotary separator turbine:

  - power from liquid phase: 21 kWe from 6742 kg/h at 177°C

  - resource utilization efficiency:
    12.0 Wh/kg for RST and flash steam turbine
    9.6 Wh/kg for optimized 1-stage flash steam turbine

- Designed 54-inch RST capable of operating from 140°C to 250°C

- Compared advanced concepts with each other and with conventional flash and binary

The contractors who have worked on EPRI projects in this area are Biphase Energy Systems and The Ben Holt Company. The major project, evaluation and development of the rotary separator turbine, is a cost-shared effort with major funding coming from Biphase as a joint venture of Research Cottrell and Transamerica Delaval.

Upstream Removal of Noncondensable Gases The objective of the EPRI projects on removal of noncondensable gases from geothermal steam is the elimination of these problems:

- Hydrogen sulfide (H_2S) odor nuisance constraining geothermal power development

- Corrosion induced by acid gases

- Loss of net power output by diversion of steam or power to eject noncondensable gases from the condenser.

The principal results of the EPRI projects in this area are as follows:

- Upstream condensing and reboiling tested at The Geysers with a heat exchanger unit processing a steam flow of about 400 kg/h (50 kWe equivalent):

  - over 90 percent H_2S removed, average removal 94 percent

  - heat transfer good enough for acceptable cost of heat exchanger at commercial size.

- Upstream copper sulfate scrubbing studied by laboratory tests and engineering assessment for application to flashed steam

- Preliminary designs and cost estimates obtained for improved upstream condense/reboil units.

The contractors who have performed this work are Coury and Associates on the heat exchanger for upstream reboiling and EIC Laboratories on the copper sulfate scrubber. The field test of the upstream reboiler was supported by Pacific Gas and Electric Company through provision of a site, field and laboratory support and other cooperation.

EPRI Project Reports Papers on 14 EPRI geothermal projects are contained in the following section of these Proceedings. As a guide to these papers, Table 1 has been prepared to summarize the projects by listing the contractors, the problems addressed and the principal products of the work.

Table 1

GUIDE TO EPRI PROJECTS PRESENTED AT THE FIFTH EPRI GEOTHERMAL CONFERENCE: SAN DIEGO, JUNE 23-25, 1981

Contractor	Problem Addressed	Product	Page
Section 5A: Assessments:			
Stanford University	Reservoir Assessment	Manual on Techniques	1
PFR Engineering	Binary Plant Performance	Data on Magma's Plant	5
United Technologies	Best Use of Geopressure	Study of Hybrid Concepts	11
Ben Holt Company	Best Conversion Cycles	Survey/Study of Concepts	24
ARINC Research	Assuring High Availability	Analysis of Heber Binary Plant Design	32
Section 5B: Field Tests:			
Biphase Energy Systems	Efficient Resource Use	Preparation for Wellhead Test	1
Coury and Associates	Upstream Gas Removal	Results from Test Unit	5
Pacific Gas and Electric	Upstream Gas Removal	Plan for Pilot Plant	21
Rotoflow Corporation	Turbine for Binary Plant	Conceptual Design	23
Bechtel Group	Scale Formed in Turbine by Brine Carried in Stream	Evaluation of Steam Separators	31
Section 5C: Chemistry			
Bechtel Group	Control of Scale Formation	Study of Crystallizer Concept	1
Sierra Pacific Power	Control of Scale Formation	Heat Exchanger Test Unit	11
EIC Laboratories	Upstream H_2S Removal	Tests/Study of Scrubbing with Copper Sulfate	13
Rockwell International	Mineral/Gas Content of Fluids	Use of Mobile Chemistry Laboratory	17

EPRI GEOTHERMAL PROJECTS - OVERVIEW

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The purpose of this talk is to describe four geothermal projects, which have been active this year and which I have been managing. Three of these projects will be discussed further at this meeting by the respective contractors. The four projects are:

- 653 Geothermal Computer Codes
- 741 Mobile Laboratory
- 1671-2 Advanced Geopressured Systems
- 1197-3 Copper Sulfate H_2S Removal

The purpose of the first project, Geothermal Computer Codes, 653, was to develop, test and distribute geothermal computer codes that can predict scale and corrosion in geothermal systems. The code can be used in several ways:

- As an aid in power plant design. A designer can simulate the scale and corrosion consequences of several plant configurations or assess the scale producing potentials of varying the parameters of a single configuration.

- To estimate actual brine constituents from ambiguous analytical data. By "initializing" the brine with the computer codes, one can account for loss of gases, oxygen contamination, etc. in the measured brine quantities.

- To determine the effect of downhole or formation flashing on brine constituents, and on scale formation in the well or aquifer.

- To determine the effects of mixing different fluid streams. This is particularly important in areas like the Imperial Valley in which make-up injection water may be required.

- To aid in interpreting results of equipment field tests, such as heat exchanger tests and the condenser-reboiler upstream H_2S abatement method.

To accomplish these objectives, the following codes were written:

- EQUILIB, an equilibrium chemistry computer code;
- FLOSCAL, a chemical kinetics and fluid dynamics code;
- WELL, a code modelling flow and flashing in a geothermal well;
- PLANT, which simulates power plant performance as scale levels in the plant increase;
- GEOSCALE, an executive code that models scale deposition and power plant performance over time, with a given input brine (calling PLANT and FLOSCAL as subroutines).

The first three of these codes (EQUILIB, FLOSCAL and WELL) have been extensively tested. Specifically, eight "case studies" were performed (listed in Table 1) using real-world field data to test the code's capabilities.

The codes are now complete, and a summary report and workshop report will be available soon. We expect the codes to be licensed for distribution through the Electric Power Software Center by the end of the year. They will not be reported on further in this session.

The Mobile Geothermal Laboratory (741) was designed to provide on-site chemical analysis using standard methods to:

- Derive a consistent chemical "signature" of a geothermal field (build the "brine data base").
- Support EPRI and utility field tests.

The laboratory has been quite active in the year since the last annual meeting. The reproducibility of sampling and analysis were characterized, and the first "signature test" was taken at the federal well site near East Mesa, California.

Next the laboratory went to Brazoria, Texas, where it performed a signature test on the geopressured well, Pleasant Bayou #2. At this site, the lab sampled both the gases separated at the 800 psi separator, and the gases that remained dissolved in the reinjected brine. The two gases were quite different in make-up as shown in Table 2. It is clear from this analysis that the high pressure separator recovers most of the methane, leaving a high CO_2 gas stream in the reinjected fluid.

Subsequently, the laboratory went to Brawley, California to support the SCE Brawley pilot plant, and to Dixie Valley, Nevada to support Project 1525-1, heat exchanger tests.

Next year, the laboratory will be equally busy. Plans include more geopressured tests, and further support of EPRI field tests. (Steam separator, Project 1672-1, and Rotary Separator Turbine, Project 1196). Support of Utah Power and Light's planning efforts is also expected. This project will be reported at this meeting by the contractor.

The Geopressured Advanced System project (1671-2) developed concepts for wellhead geopressured power generation, using all geopressured methane and thermal energy on-site. In this project, small gas turbines and gas engines used all the methane of a single well, and the thermal energy of that well was used in a flashed or binary bottoming cycle. Twenty configurations were evaluated from a thermodynamic and reliability standpoint. Gas engine-flash and gas turbine-binary plants were selected for further evaluation. Some of the conclusions of this study were that:

- More thermally efficient power plants are possible with these combined cycles;
- Combined cycles save the costs of pressurizing methane for pipeline sales;
- The overall economics is very sensitive to the amount of gas in the brine;
- The comparative economics (combined cycle versus selling methane off-site) is very sensitive to the price received for the gas.

The final report for this project is under review. The project will be reported at this meeting by the contractor.

The last project to be discussed is the Copper Sulfate H_2S Removal Process (RP1197-3). In this project, the copper sulfate process was evaluated for use in flashed steam conditions. In general, as in any scrubbing process, there is decreasing cost with increasing steam input pressure, and increasing costs and decreasing efficiencies with decreasing H_2S concentration. The investigators of the project assumed that less abatement would be required for lower H_2S concentrations.

The report for this project is in final typing. The project will be reported at this meeting by the contractor.

TABLE 1 CASE STUDIES

- Heber 2000 hr Heat Exchanger Tests
- Cerro Prieto Flashing Wells
- Kizildere Flashing Flow Tests
- Power System Equipment Module Tests
- RGI East Mesa Flash Tests
- Flashing Flow in Porous Media
- SCE Flash Plant at Heber
- Heat Exchanger Method of H_2S Removal

TABLE 2
GEOPRESSURED GAS ANALYSIS

Analyte	Separator	Dissolved
Amount SCF/BBL	22	7
Pressure PSIG	800	10
CO_2 (mole %)	12.3%	55.8%
Methane (mole%)	83.9%	42.8%
Ethane (mole %)	1.75%	0.70%
Propane (mole %)	1.18%	0.21%
Hydrogen (ppm volume)	300 ppm	1300 ppm

RESEARCH AND DEVELOPMENT PROJECTS

Advanced Power Systems Division
Renewable Resources Systems Department

GEOTHERMAL POWER SYSTEMS

+RP375 - Geothermal Exploration Methods and Techniques: Contractor: University of Texas, Dallas. Final Report No. ER680 (Project No. RP375), February 1978.

+RP376 - Test and Evaluation of a Geothermal Heat Exchanger: Contractor: San Diego Gas and Electric Company. Final Report No. EPRI376, November 1975.

+RP556 - Environmental Baseline Data Acquisition - Heber: Contractor: San Diego Gas and Electric Company. Final Report No. ER352, February 1977.

+RP580 - Low-Salinity Hydrothermal Demonstration Plant: Contractors: Holt/Procon and San Diego Gas and Electric Company. Final Report No. ER1099 (Project No. RP580-2), June 1979.

RP653 - Computer Simulation of Scale Formation in Geothermal Systems: The objective is to develop an analytical capability to predict precipitation of solids and scale formation caused by geothermal brines in geothermal power systems. First-phase work included the development of a methodology for calculating the equilibrium brine chemistry, laboratory experiments on the kinetics of scaling, and power plant modeling. Battelle, Pacific Northwest Laboratories is the contractor. Interim Report No. ER635 (Project No. RP653-1), Vols. I and II, January 1978. The second phase incorporated a scaling kinetic model and a capability to calculate scale deposition in geothermal flow streams. The present phase of work involves a number of case studies.

RP741 - Mobile Geothermal Fluids, Materials, and Components Test Laboratory: The objectives of this project are: (1) to support field testing of geothermal fluids and critical components; and (2) to develop detailed knowledge of geothermal fluid characteristics for a better understanding of site-to-site variability. The construction of the mobile chemical analysis laboratory is complete, and field use has begun. Rockwell International Corp. is the contractor.

+RP791 - Study of Brine Treatment: Contractor: Lawrence Berkeley Laboratory. Final Report No. ER476 (Project No. RP791), November 1977.

+RP846 - Geothermal Heat Exchanger Test: Contractor: The Ben Holt Company. Final Report No. ER572 (Project No. RP846-1), August 1978.

+RP927 - Waste Heat Rejection from Geothermal Power Plants: Contractor: R. W. Beck. Final Report No. ER1216 (Project No. RP927-1), October 1979.

+RP928 - Hydrocarbon Expander Turbine Design: Contractors: Elliott Company, Rotoflow Corporation, and C. F. Braun & Co. Final Report No. ER513 (Project No. RP928-1), May 1979; Final Report No. ER1034 (Project No. RP928-4), March 1979.

+ denotes that the project is finished

RP929 - Geothermal Reservoir Assessment Techniques: The objective of this study is to collect information on the generally accepted techniques for assessing geothermal reservoirs and compile these into a single reference document for use by utilities. The scope of the document will be limited to hydrothermal and geopressure reservoir types. The contractor is Stanford University.

RP1094 - Binary Cycle Equipment Test: The objective of this project is to develop experience with small-scale, binary cycle, heat exchanger modules designed to simulate typical power systems. The results are expected to include: (1) Benchmark data of system operating characteristics; (2) data of heat transfer, scaling, and corrosion; and (3) performance of two candidate hydrocarbon working fluids. This project is funded by EPRI and DOE, with Lawrence Berkeley acting for DOE. Colley Engineers & Constructors, Inc., and J. R. Schilling are the contractors.

RP1195 - Assessment of Critical Geothermal Technical Issues: The goal is to establish a data base for use in geothermal power plant design, reliability, and operation. Data will be gathered from four sources: (1) the Cerro Prieto flashed steam power plant operating data; (2) Magma Power Company's proposed 11.2 MWe binary cycle experimental plant; (3) experimental data on mineral and construction material solution in geothermal brines and their chemical kinetics; and (4) plant performance effects of adding acid to geothermal brines. The contractors are: Stanford University; Systems, Science and Software; PFR Engineering Systems, Inc; Arizona Public Service; and Colley Engineers.

RP1196 - Field Evaluation of Rotary Phase-Separator Turbine: The objectives of this project are to evaluate the performance and to assess the potential of total flow power conversion systems that generate electricity from water-dominated geothermal resources. A bench model hydraulic turbine, coupled to a rotary steam separator has been built and tested at three geothermal sites as a single flash/separator/turbine unit. A pilot plant is being designed and built for operation at a site where it will accept the total flow from a hydrothermal well. Biphase Energy Systems, a joint venture by Research-Cottrell and Transamerica Deleval, Inc., is the contractor and the cosponsor. Biphase Energy Systems is the contractor and cosponsor.

RP1197 - Upstream Removal of Hydrogen Sulfide (H_2S) from Geothermal Steam: The objective of this project is to assess the design criteria, cost, operational factors, and removal efficiency of two methods for upstream removal of H_2S from geothermal steam - a heat exchanger process and a copper sulfate scrubbing process. The heat exchanger process is being tested at The Geysers through a cooperative effort with Pacific Gas and Electric Company. Coury & Associates, Inc., is the contractor for field testing of the heat exchanger process, and EIC Laboratories is the contractor for laboratory experiments on copper sulfate scrubbing.

+RP1272 - Assessment of Economics and Technologies for Geopressure Energy Extraction: Contractor: Southwest Research Institute. Final Report No. AP1457 (Project No. RP1272-1), July 1980.

RP1525 - Control of Scaling in Geothermal Power Systems: In the assessments made by this project of current scale control methods for geothermal applications, the following approaches will be analyzed and compared: use of chemical additives to inhibit scale formation; chemical and mechanical removal of scale; and stimulated precipitation with solids removal. At least one concept for scale control will be developed in this project with the objective of

+ denotes that the project is finished.

reducing by 50% the outage rate due to scale accumulation. Sierra Pacific Power Company and Bechtel National, Inc., are the contractors.

RP1671 - Geopressure Energy Conversion - Preferred Systems: The objective of this project is to evaluate concepts for geopressure energy recovery systems. These systems will be based on multi-use and single-use, e.g., combustion engines with combined cycles for power production from both methane and heat. The evaluation will be made from conceptual designs of integrated power systems. The contractor is United Technologies Corporation.

RP1672 - Geothermal Fluid Process Technology: The objective of this project is to evaluate different steam separator designs to determine the optimum separator application as a function of operating conditions. The evaluation begins with a technical assessment and then focuses on the design and operation of a steam separator test system at a geothermal site. The contractor is Bechtel National, Inc.

RP1673 - Geothermal Technology and Economic Assessment of Advanced Power Generation: The objective of this project is to estimate to the year 2000 the impact of emerging technologies on the growth of geothermal power operation. A number of concepts for improving geothermal power conversion systems are being compared to conventional flash and binary geothermal power systems. The contractor is The Ben Holt Company.

RP1900 - Binary Cycle Geothermal Demonstration Plant: The objective of this project is to design, construct, and certify the first large-scale, binary-cycle, geothermal power plant for commercial operation by 1986. In this project the technical performance, the environmental acceptability, and the economic feasibility of the binary-cycle technology will be demonstrated for moderate temperature geothermal resources. DOE and several utilities are cosponsors of this project; the contractor is San Diego Gas and Electric Company.

*RP1991 - Support to 50 MW(e) Direct Flash Demonstration Plant Field Data Evaluation: The objective of this project is to conduct an independent assessment of the 50 MW(e) flash steam plant at Baca, New Mexico. The tasks of this project are: to compare design specifications of the reservoir, steam, and power systems at Baca with other sites; to identify critical components for which further research could reduce costs or improve performance; to prepare plans for testing significant improvements; to design a data analysis system for calculating plant performance; and to analyze, evaluate, and report plant performance.

*RP1992 - Reservoir Risk Assessment Techniques: The objective of this project is to develop a quantitative risk assessment methodology for geothermal plants, taking into account regional geological distribution probabilities and particular properties of the reservoir such as temperature, pressure, permeability, height of the producing zone, and diameter of the well. This methodology will meet the requirements for information on geothermal power development needed by utilities in determining generation expansion plans, commitment to plant construction, terms of contracts with energy suppliers, and designs of power plant and production/injection systems.

*RP1994 - Assessment of Advanced Geothermal Conversion Concepts: The objective of this project is to conduct preliminary assessment studies on selected concepts and conversion options for geothermal energy conversion and direct utilization. Possible examples of these concepts are alternate methods of hydrogen sulfide abatement, well-head conversion systems, scale control and fluid treatment, and energy recovery and heat rejection. This project could also investigate hot dry rock and geopressure options.

* denotes that a contract is not yet signed.

GEOTHERMAL RESERVOIR ASSESSMENT MANUAL

CONTRACT # 929-2

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Introduction

The increasing cost of fossil fuels has led many utility companies to consider development of geothermal energy as a source of electrical power. Because only a few utilities in the entire world have practical experience in development of geothermal energy, few utilities are prepared to handle the complex problem of geothermal power development. As there are many different types of gas and oil producing reservoirs, there are a host of different types of geothermal systems. Proper assessment of geothermal reservoirs requires the talents of many trained technical experts. Examples include mechanical engineers, and civil engineers for power plant siting and design; geologists, and geochemists, and geophysicists for exploration for geothermal systems and planning initial drilling, petroleum engineering drilling engineers for drilling of exploratory and development wells; petroleum production engineers for operation of wells and testing of wells; and petroleum reservoir engineers for evaluation of the geothermal system and planning of the development of the system. Although some of these specialties may be in-house talent for certain utilities, it is rare that any utility has access to specialists in all of these fields. It is often not obvious to utility staff which of these specialties are required to answer important problems. The main objective of this project was to prepare a reservoir assessment manual to guide utility staffs in planning the development of geothermal reservoir systems. In addition to preparation of a manual outlining the state of the art of this new technology it was also intended to prepare new answers to existing questions which have not previously been handled. The problems considered in this category generally concern the producing characteristics of both dry steam and boiling liquid geothermal wells. Four original studies were conducted and reports prepared. The following presents a description of the reservoir assessment manual and an example of the kind of information made available through original researches conducted in this study.

Description of Manual

Table 1 is an outline of the reservoir assessment manual. This outline is a far more detailed outline than the outline presented in our previous report, "Geothermal Reservoir Assessment Techniques Manual" by Sanyal, et al., EPRI 1977 Annual Meeting Proceedings. Although most of the intent and planning of the original manual are included in the outline shown in Table 1, preparation of the manual revealed weaknesses in the original plan. For example, the original planned outline did not include coverage of drilling, and some information in the original planned outline has been moved to provide continuity in presentation of the information.

Most mineral fluids producing companies are organized in parallel: an exploration division and a producing division. The exploration division includes the technical specialists involved in locating properties worth drilling for test, and the producing division includes all technical specialists involved in drilling development wells, planning the development and conducting the production of the fluid. Although both divisions must operate simultaneously in parallel, it is necessary to complete the exploration phase of the development of a specific property prior to the development of the producing division's function. For this reason the manual was planned in a sequence to indicate the near chronological operations involved in the finding, drilling, and development of a geothermal producing system. Figure 1 is a flow chart of various geothermal assessment activities.

We return now to Table 1 and a brief discussion of the outline of the reservoir assessment manual. Section One will present an introduction to the manual and state the objective for the development of the manual. It will discuss the petroleum reservoir assessment and identify problems specific to the geothermal systems.

In addition it will attempt to identify utility viewpoint and the need for this manual to serve utility staff members.

Section Two will provide a brief discussion of the specialists involved in exploration for geothermal systems and the types of operations that they conduct to identify geothermal systems. For example, geochemists are able to analyze the waters flowing from the earth and from various chemical constituents to determine that the water was in equilibrium at certain temperature levels. This makes it possible to identify that even cold effluents from the earth had been previously heated to temperatures characteristic of geothermal fluid rock systems. Another example is in the area of geophysics. Surface measurements of the electrical resistivity of rocks, the geothermal temperature gradient in the near surface, and the transmission of sound waves through the earth often will permit identification of systems containing steam or hot brines.

Once a potential geothermal system has been identified it is necessary to drill a well to test the potential geothermal reservoir. Section Three in Table 1 will provide a brief discussion of drilling because drilling activities are not a common part of the operations of most utilities. Although much geothermal system drilling is quite similar to drilling for gas or oil, special problems caused by low pressure steam systems and high temperature brine systems will be identified.

Section Four in the manual will contain a discussion of formation evaluation from an existing drilled bore hole. Ordinarily it is possible to run a variety of wire line well logs in a bore hole to make geophysical measurements which can be interpreted to yield important information about the rocks and the fluid contents of the rocks encountered in drilling the well. This sort of work is frequently done by geologists, geophysicists, and petroleum engineers.

Section Five presents one of the most important areas of reservoir testing once the well has been drilled. It is possible to drill a well through a fluid bearing formation and yet see no evidence of the presence of the important fluid. A variety of pressure transient tests may be run in wells to determine the existence of important quantities of reservoir fluids and to obtain early information about the potential fluid reserves in the system. This is a complex system depending upon high level mathematics and is generally the province of either the groundwater hydrologist or a petroleum reservoir engineer.

Once a well is produced and hot fluid moves from a formation up the wellbore to the surface heat transmission enters the problem. The loss of heat from hot fluids in a wellbore to cold adjacent earth is the main subject of Section Six in the manual. This problem also arises in another way. The cooled fluids from a power plant are frequently reinjected back into a formation. As cold fluid passes down a well it encounters hot formations and gains heat. Heat flow to and from a wellbore is a matter of great importance in the production of geothermal energy.

Section Seven in the manual concerns wellbore fluid flow. There have been a number of important cases where geothermal wells were drilled and the fluid producing capability of the bore hole was extremely limited. In some cases the reason for poor productivity of a geothermal well was that the formation was poor and either contained little fluid or had such low conductivity that it would not transmit fluids. On the other hand the reason for poor productivity is sometimes the result of plugging of the formation near the wellbore or flow restrictions within the wellbore as the fluid passes from the formation to the surface of the earth. In the case of the geothermal well HGPA drilled by the University of Hawaii on the big island of Hawaii, formation plugging was serious and led to initial speculations that the well would not be productive. This well has continued to improve since the time of completion. On another occasion, a poor well drilled in The Geysers field was found to be a result of obstructions within the wellbore. Material near the bottom of the well choked the flow from the formation to the surface of the earth. A major research was conducted in this project on the producing characteristics of wellbores. This work included both the flow of single phase steam and multi-phase flow. Four master of science reports were prepared in the petroleum engineering department at Stanford[1-4]. An example of the results of this study is included in the next section of this report.

Sections Eight and Nine in the reservoir manual deal with well deliverability and material and energy balance performance of geothermal reservoirs. These two sections cover important portions of the reservoir engineering of geothermal fluids systems. Two significant reservoir engineering questions are: what is the potential deliverability of a system (how many wells will be required] and how much fluid is present, or what are the fluid reserves? The term "steam reserve" is used by many of the specialists involved in geothermal systems in different senses. These sections will cover important concepts as far as the production of geothermal systems and establishment of lifetime are concerned.

Section Ten concerns the subject of reinjection of cool geothermal fluids. The cool geothermal fluids may contain salts and materials which may be injurious to plant or animal life. Thus there is a need to treat these materials as waste containing materials. On the other hand, production of fluids may lead to subsidence of the surface of the earth and to depletion of the reservoir fluid. Because of the depletion of fluids in geothermal systems due to extremely high producing rates, the reinjection of fluids for both waste disposal and proper reservoir management is an important subject.

Section Eleven will contain concluding remarks on the manual and attempt to provide a basis for understanding of the risk involved in assessment of geothermal systems. Other sections in the manual will contain nomenclature, engineering units, and appendix items as needed.

Wellbore Fluid Flow

A major research effort was conducted in this project on wellbore fluid flow. This is a subject of established importance to gas and oil production. Although steam is frequently injected into oil wells to aid oil recovery, it is rare that steam is injected at rates approaching the magnitude of the monumental producing rates from geothermal steam wells. Because of the high velocities encountered in geothermal steam producing wells, it appeared necessary to conduct a fundamental investigation of the wellbore fluid flow behavior of both single phase and multiphase geothermal fluid producing wells. This study led to the production of four Master of Science reports at Stanford University.

An example of the importance of this kind of study is presented by Baza[2]. See also reference 5 by Morales-Gil, et. al. The well was drilled in a dry steam field to a depth of 8,000 feet. The producing characteristics of this well were disappointing in that the well would produce only a little over 80,000 pounds of steam per hour from a reservoir wherein good wells would frequently produce 300,000 pounds of steam per hour. It was initially believed that the well had encountered a poor portion of the reservoir. However, when the producing characteristics of the well were computed using the methods developed in this research, the results shown in figure 2 were obtained. Figure 2 presents the mass flow-rate through a well completed in a manner similar to that found in the field case, as a function of the producing well head pressure. It can be seen from figure 2 that the maximum rate possible from this well is less than 90,000 pounds per hour.

The conclusion from this calculation was that the wellbore itself contained flow restrictions sufficient to limit the mass flow rate possible from the well. The formation was not the controlling factor and was capable of much higher flows. The unique feature about the calculations involved in references 1 through 5 is that the possibility of critical choking and the loss of energy by heat conduction from the wellbore are both included in the study. One product of this study is pre-computed graphs that will permit a utility to consider well completion and see immediately the maximum steam producing rates possible from a well.

References

1. Morales-Gil, C.: "Effect of Chokes and other Restrictions on Pressure Drop in Geothermal Wells", MS Report in Petroleum Engineering, Stanford University, June 1978.

2. Baza, John R: " Calculation of the Performance of Dry Steam Wells", MS Report in Petroleum Engineering, Stanford University, July 1979.

3. Tai, T.: "Wellhead Evaluation of a Geothermal Effluent" MS Report in Petroleum Engineering, Stanford University, April 1979.

4. Fandriana, L.: " A Numerical Simulator for Fluid Flow in a Geothermal Well", MS Report in Petroleum Engineering, Stanford University, July 1979, 92 pages.

5. Morales-Gil, C., Baza , J.R., Ramey, H.J., Jr., and Sanyal, S.K.: "Calculation of Performance of Dry Steam Wells", Geothermal Resources Council, Transactions, Vol. 3, Sept., 1979, pg 465.

Table 1

RESERVOIR ENGINEERING ASSESSMENT OF GEOTHERMAL SYSTEMS

1. Introduction--state problem--usual methods for petroleum reservoir geothermal special problems--utility viewpoint.

2. Exploration
   - 2.1 Geophysics - Geology
   - 2.2 Geochemistry
   - 2.3 Summary

3. Drilling
   - 3.1 Cable tool drilling
   - 3.2 Rotary drilling
   - 3.3 Air drilling
   - 3.4 Coring, mud logging, and drill stem testing
   - 3.5 Summary

4. Formation Evaluation
   - 4.1 Brief description of common well logs
   - 4.2 Detection of fractures
   - 4.3 Status of Geothermal loz interpretation

5. Pressure Transient Testing
   - 5.1 Drawdown
   - 5.2 Buildup
   - 5.3 Interference
   - 5.4 System compressibility
   - 5.5 Fracture systems
   - 5.6 Inertial effects, earth tides
   - 5.7 Summary

6. Wellbore Heat Transmission
   - 6.1 Production, single phase
   - 6.2 Injection
   - 6.3 Summary

7. Wellbore Fluid Flow
   - 7.1 Bottomhole pressure calculation (static and flowing, single and multiphase flow)
   - 7.2 Inflow performance--steam (work of Morales, Baza)
   - 7.3 Inflow performance--multiphase (work of Morales, Baza)
   - 7.4 Performance charts
   - 7.5 Summary

8. Deliverability
   - 8.1 Theory--radial, sph. flow, skin effect, parallelepiped models
   - 8.2 Rate-time graphs
   - 8.3 Δp^2 vs q on log-log graphs
   - 8.4 Rate vs wellhead pressure
   - 8.5 Summary

9. Material and Energy Balances
   - 9.1 Volumetric estimates
   - 9.2 Material-energy balance methods
   - 9.3 p/z vs steam produced
   - 9.4 Decline curve analysis, cum-time, etc.
   - 9.5 Computer modeling
   - 9.6 Summary

10. Reinjection--(Need, waste disposal, subsidence, heat scavenging)
    - 10.1 Vertical heat flow from Pet. Lit.
    - 10.2 Gringarten-sauty
    - 10.3 Computer modeling
    - 10.4 Summary

11. Remarks--The future, state of art, etc., and assessment of risk.

12. Nomenclature--SPE where possible--English units (SI units in par.)

13. Appendix

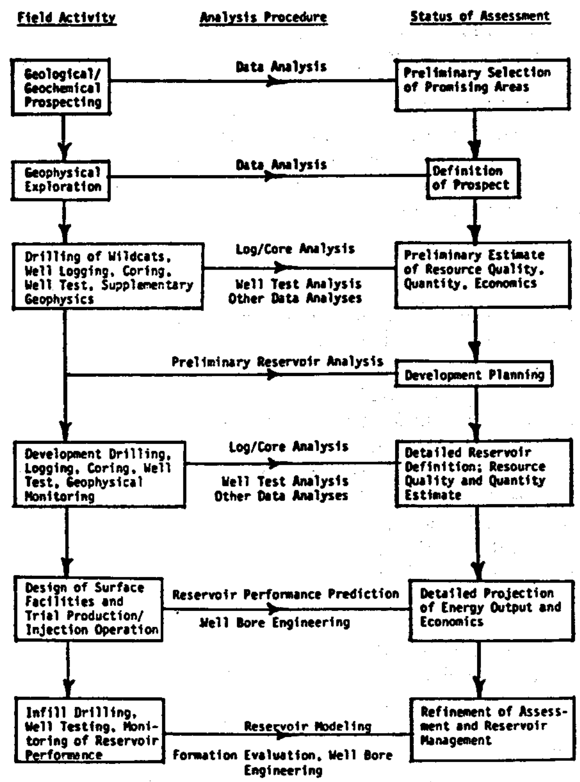

Figure 1. Flow chart of geothermal reservoir assessment

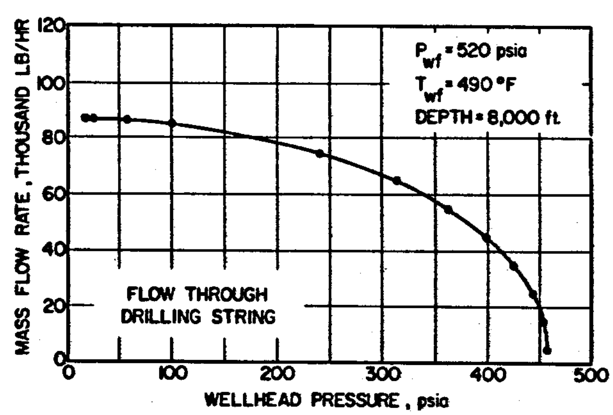

Figure 2. Computed wellhead performance curve for a dry steam well

CHARACTERIZATION OF 11.2 MWe MAGMA EAST MESA BINARY POWER PLANT

MAGMA PLANT RP#1195-3

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INTRODUCTION AND SUMMARY The Magma Geothermal Binary Power Plant at East Mesa, in the Imperial Valley, has operated for the past two years. The objective of the RP1195-3 project is to evaluate the following aspects of the plant:

- The process: "Magmamax Process"
- The components: Turbines, Heat Exchangers, Pumps, Heat Rejection System
- Data Collection System: Gathering, Reduction
- Operating History
- Performance Results
- Conclusions: Process, Components, Other Factors

The Magmamax Process uses a dual binary rankine cycle with isobutane as the working fluid in the main (topping) cycle and propane in the bottoming cycle. The overall plant is designed to produce 11.2 MWe and is shown in Figure 1. The plant was initially started in late summer of 1979 and has since then operated intermittently. The maximum power level obtained up to this date is 6.7 MWe with only the isobutane cycle in operation. The propane cycle is presently undergoing start-up after intital problems with the propane turbine.

At a gross power level of 6.2 MWe a gross cycle efficiency of 9.8% and heat rate of 34,925 BTU/kw-hr was obtained. When the amount of the power supplied to the main feed pump is taken into account the gross efficiencies increase to 10.6% and 32,200 BTU/kw-hr, respectively. There have been a series of plant stoppages caused by main and auxiliary turbines, heat exchangers and brine production pump problems. Magma is diligently correcting these problems and has ordered another isobutane turbine and designed new heat exchangers which indicate their high level of commitment to continued operation of the world's largest Binary Geothermal power plant.

THE COMPONENTS The main components analyzed on the project are the turbines, heat exchangers, pumps and the heat rejection system.

1. Isobutane Turbine - The isobutane turbine is a modified York tandem-type three-stage compressor with an intermediate extraction point. The turbine rotor was heavily damaged in November 1980 due to thermal distortion of the rotor. The unit was rebuilt by Dow Chemical Company in early 1981 and returned to service by April 1981. It currently is undergoing furthur bearing modifications and is expected to return to service in June 1981. The isentropic and mechanical efficiencies are 75% ± 10% and 85% ± 10%, respectively. The mechanical efficiency includes losses in the bearings, gear box, and electric generator.

2. Heat Exchangers - The ten brine to isobutane heat exchangers employed by the main isobutane cycle are single pass, counter current shell and tube type exchangers with 80-foot-long tubes using a novel tube support system. The unit has a floating rearhead type of construction consisting of a floating piston and cylinders which has proven unreliable in practice. The rearhead was welded to the shell and the design is now essentially a "fixed tube sheet". During start-up and operation the heat exchangers developed leaks through the rearhead assembly, thereby introducing brine into the isobutane system. New heat exchangers have been designed and Magma expects to replace the existing units. Data obtained from the first exchanger where isobutane is in the liquid phase appears reliable and produces an average overall heat transfer coefficient of 275 BTU/hr-ft^2-°F. This value is predictable from modern heat transfer prediction methods and is in the same range as those obtained from the earlier EPRI sponsored program, Pilot Scale Exchanger Module Test (PSEMT).

The fouling factors obtained over the time period of September through November 1980 are negligible. There may be a certain amount of corrosion of the tubes, but this has not been positively ascertained.

The isobutane heat rejection system consists of two parallel water cooled condensers of the shell and tube type. The water is cooled by two spray ponds and a deep storage pond. The isobutane condensers developed a leakage around the channel pass partition on the water side. A portion of the water by-passed the tubes, lowering the effectiveness of the unit starting in late October 1980. The data acquisition system monitored the loss in efficiency of the condenser. An average overall heat transfer coefficient in the condenser of 80 BTU/hr-ft^2-°F was obtained during the period when there was minimal or no leakage. The pond heat rejection system has provided

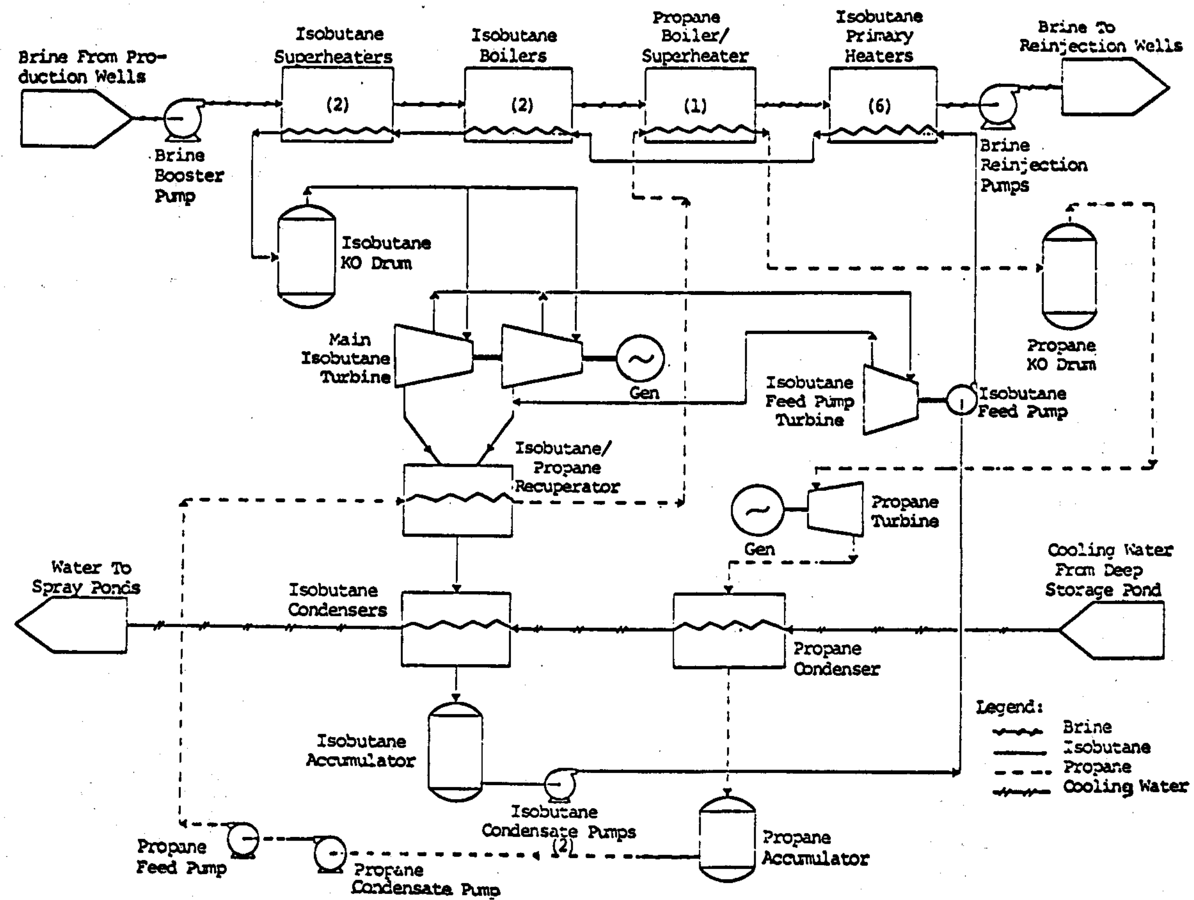


Figure 1 Overall System Schematic

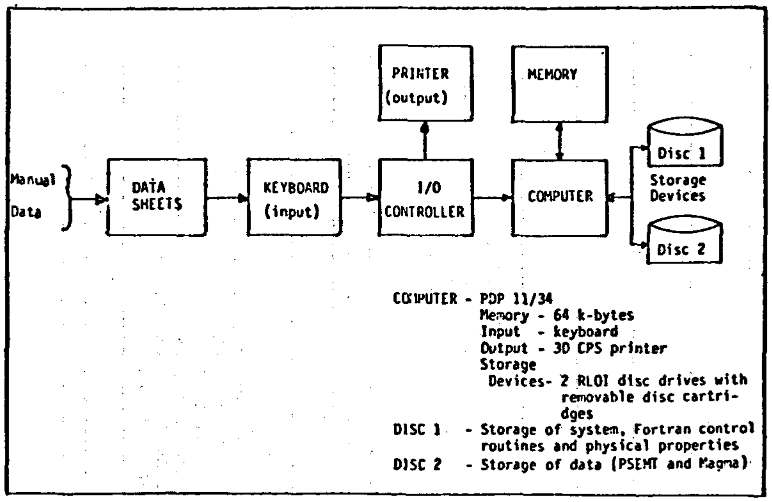


Figure 2. DATA PROCESSING SYSTEM

cooling with an approach to the wet bulb temperature which generally varies from 10 to 15°F.

DATA COLLECTION SYSTEM

1. Data Gathering - Industrial level instrumentation was used to collect data at all important locations in the plant. The main data required are temperatures, pressures, flow rates of the main process stream, and the electrical power generated and consumed. A portion of the data was obtained from the main control room and the remaining from local field instrumentations. Usually two operators are required to record data simultaneously from the control room and local stations. This data was then checked for inconsistencies or missing data before logging into the computer systems (Figure 2). The data is checked by a computer program again before it is reduced. The computer software makes use of the steady state models of the overall process and individual components using well recognized correlations.

OPERATING HISTORY Since the start-up of the plant in the summer of 1979 it has encountered several problems with the key components. These are summarized below.

- Brine to isobutane leaks through the piston and cylinder assembly in the rear heads of main heat exchangers
- Tube to tube sheet leaks in the main heat exchangers
- Breakdown of main brine production pumps
- Main isobutane turbine breakdown due to shaft coupling failure
- Main isobutane turbine breakdown due to damage to the rotor blades from possible thermal distortion
- Propane turbine breakdown due to shaft failure
- Water bypassing in the condensers

Magma has continuously reviewed these problems and solved them as they appear.

RESULTS Typical results obtained from data taken on September 3, 1980 are reported in Figure 3, which is a computer printout. The figure provides the performance results used to evaluate the overall process and individual components efficiency. The overall process performance parameters are summarized in Table 1.

The uncertainty involved in these results is estimated to be in the range of 10-20% depending upon the complexity of computations involved and the kind and amount of data used. The amount of data reduced to date is not sufficient to indicate the repeatability of the results. More data will be processed after the start-up of the plant and an attempt will be made to verify the repeatability of results.

CONCLUSIONS The maximum power level obtained to date is below the design values. Several factors are responsible for this low power production. Some of the main factors are lower brine flow rates, higher ambient temperatures and lower isobutane enthalpies at the inlet of main turbines. Table 2 summarizes these cases.

The sink temperature has a direct effect on the power production. Figures 4 and 5 show the effects of changing sink temperature on the power output of the isobutane main turbine and propane turbine, respectively. As the sink temperature goes up the back pressure on the turbine increases resulting in lower

TIME START : 20:00
TIME COMPL.: 20:30
OPERATOR : JAY

** MAGMA TESTS COMPUTER OUTPUT **
NO HOURS FROM START OF SERIES : 20

RUN : /SERIES: 14/ 9
RUN DATE : 9-3-80
CURRENT DATE :17-SEP-80

PAGE : 2

** PERFORMANCE DATA **

** HEAT EXCHANGERS **	BRINE DUTY (1000 BTU/HR)	HYDROCARBON DUTY (1000 BTU/HR)	% DIFF.	LMTD (DEG F)	OVERALL U (BTU/HR-FT2-F)	MEASURATED FOULING FACTOR (HR-FT2-F/BTU)
1) ISOBUTANE HEATERS	111063.0	106772.9	-3.9	35.98	216.9	0.00110
2) C3 SUPERHEATER	0.0	0.0	0.0			
3) I-C4 BOILERS,SUPERH.	105470.6	97130.2	-7.9			
4) TOTAL HEAT DELIVERED	216533.5	203903.0	-5.8			
5) RECUPERATOR I-C4/ C3	54.1	0.0	0.0			
	WATER DUTY					
6) PROPANE CONDENSER	0.0	0.0	0.0			
7) I-C4 CONDENSER	211888.2	211888.2	0.0			
8) EAST	100127.5					
9) WEST	111760.7					
10) TOTAL HEAT REJECTED	211888.2	211888.2	0.0			

** TURBINES AND FEED PUMP **	POWER PRODUCED (1000BTU/HR)	(KW)	2-ND LAW EFFICIENCY (POWER/DIFF.AVAIL.WORK)	ISENTROPIC EFFICIENCY	MECHANICAL EFFICIENCY
11) I-C4 MAIN TURBINE	21154.4	6200.0	0.7442	0.75	0.9445
12) I-C4 B. F. PUMP TURBINE	892.6	261.6	0.4459	0.9761	0.5426
13) C3 - MAIN TURBINE	0.0	0.0	0.0000	0.0000	0.0000
14) TOTAL TURBINE (11)+13))	21154.4	6200.0			

** OVERALL PLANT EFFICIENCY **	GROSS	NET	
15) HEAT RATES (BTU/KW-HR)	34925.	63686.	
16) FIRST CYCLE EFF. (%)	9.770	5.358	
17) SPECIFIC POWER OUT (BTU/LB BRINE)	16.924	9.281	
18) RESOURCE UTILIZATION EFF.(HEAT)	0.9069		(MAX. WORK DELIV./ MAX. WORK AVAILABLE)
19) RESOURCE UTILIZATION EFF.(POWER)	0.3872	0.2123	(POWER OUT / MAX. WORK AVAILABLE)
20) SECOND LAW CYCLE EFF	0.4269	0.2341	(POWER OUT / MAX. WORK DELIV.)
21) NET RESOURCE THERMAL EFFICIENCY	0.0615	0.0337	(POWER OUT / MAX. AVAILABLE ENTHALPY)
22) HEAT TRANSFER EFFICIENCY	0.6376	-	(ENTHALPY DELIV. / MAX. AVAILABLE ENTHALPY)
23) PARASITIC LOSSES	0.4516	-	(POWER CONSUMED / POWER PRODUCED)

** POWER CONSUMED **	KW	= AMPERAGE	* VOLTAGE
24) SPRAY PUMPS	0.0	0.0	4160.0
25) PRODUCTION PUMPS	0.0	0.0	4160.0
26) CIRCULATING WATER PUMPS	0.0	0.0	4160.0
27) GENERAL POWER	0.0	0.0	4160.0
28) TOTAL POWER USED	0.0		

** NET BUS-BAR POWER DELIVERED **	KW
29) MEASURED	3400.0
30) COMPUTED	3400.0

Figure 3

Table 1 Overall Plant Efficiency

		Design	Operations (9/3/80)
1.	Overall Cycle Efficiency, % (first law)	12.9	9.8
2.	Heat Rates (BTU/kw-hr)	26,500	34,925
3.	Specific Power Out (BTU/lb of Brine)	23.6	16.9
4.	Parasitic Losses, % (Power Consumed/Power Produced)	12.0	45.0

Table 2

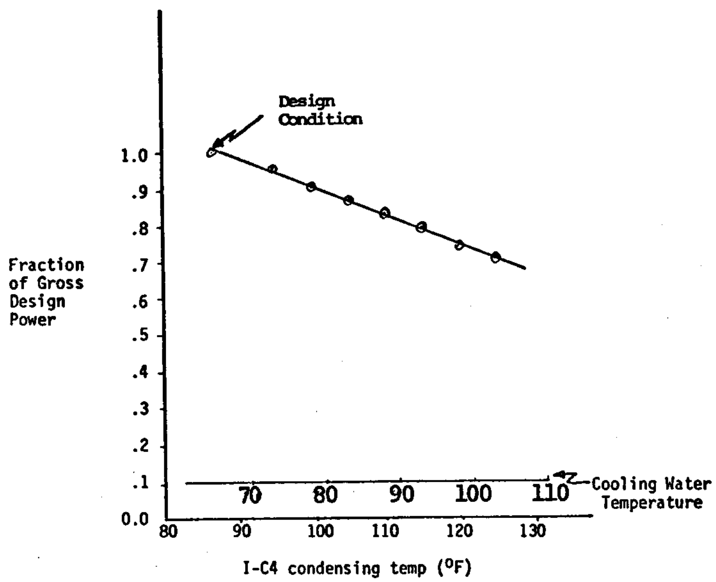
	Item	Percent Loss
1.	Low brine flow rate	13%
2.	Efficiency of heat rejection system	17
3.	Lower isobutane enthalpy at the turbine inlet	10
	Total	40%

power output. The figure indicates a linear relationship between the power level and cooling water temperature over the range examined.

The major conclusions which can be drawn from the plant are the following:

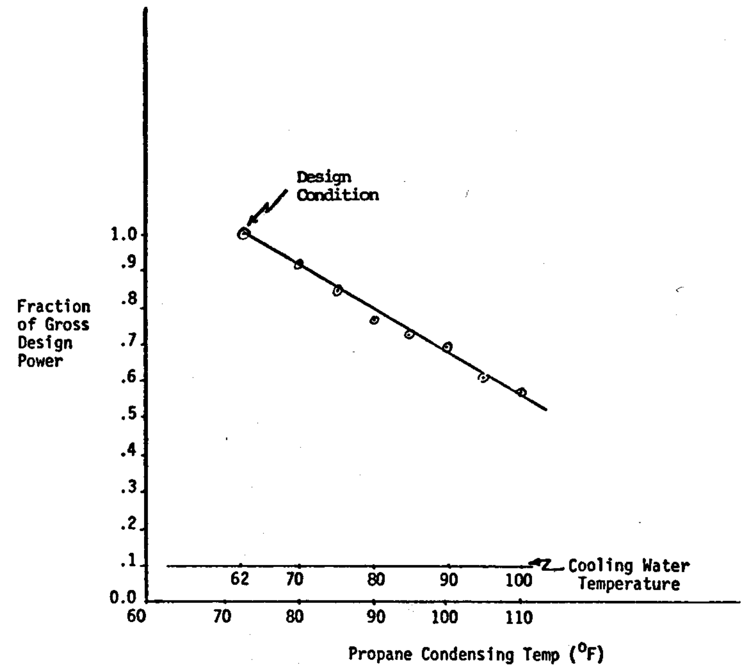
- The performance of the brine heaters and condensers can be accurately predicted through use of modern heat transfer technology
- Efficient cooling towers are the most practical heat rejection system for geothermal power plants
- The efficiency of major components and of the Binary system have been proven to be high.

Figure 4 Effect of Sink Temperature on I-C4 Circuit



Note: Gross Power does not take into account any intermediate extraction streams

Figure 5 Effect of Sink Temperature on Propane Circuit



HYBRID POWER PLANTS FOR GEOPRESSURED RESOURCES

CONTRACT No. RP 1671-2

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Summary The objective of this project was to assess the technical and economic feasibility* of hybrid power plants which simultaneously utilize the methane, thermal and hydraulic energy produced by a single geopressured well. A large number of hybrid power plant configurations, comprising both gas engine and gas turbine topping systems in combination with bottoming flash and binary systems, were screened according to preliminary performance and reliability criteria. Gas engine-topped double-flash systems and gas turbine-topped dual-pressure binary systems were chosen for further detailed analysis. Extensive thermodynamic optimization and sensitivity analyses were performed to determine the design and operating conditions corresponding to peak output for two representative geopressured resources: the S. E. Pecan Island resource, and the Pleasant Bayou #2 resource. The capital and operating costs were estimated for each system/resource combination, and were employed to calculate the levelized cost of electricity. The hybrid plants were compared with conventional flash and binary geopressured power plants and were found to be both thermodynamically and economically superior. The levelized cost of electricity produced by the hybrid plants was found to be 40-50 percent lower than the cost of that produced by the conventional geopressured plants.

Introduction Geopressured-geothermal reservoirs contain highly pressurized hot brine, often saturated with dissolved natural gas. As such, they are endowed with three energy components: hydraulic (highly pressurized), thermal (hot brine) and chemical (dissolved natural gas).

Previous studies of geopressured resource utilization (1,2,3) considered gas as the primary commodity to be extracted from these valuable resources, subordinating potential generation of electric power from the thermal and hydraulic components to the separation and processing of natural gas. None of these studies considered the feasibility of using the natural gas on-site, in addition to the thermal and hydraulic energy, to generate electricity by means of hybrid (or total) energy conversion systems. Hybrid systems for the total utilization of geopressured resources were proposed as early as 1977 by the author (4). In these systems, after converting the hydraulic energy into work by means of a suitable hydraulic turbine, the separated natural gas is used to fuel a topping combustion prime mover whose waste energy is used in combination with the brine thermal energy to generate additional work by means of a bottoming vapor power system. Preliminary studies at United Technologies Research Center (UTRC) identified several hybrid power generation systems that would efficiently utilize the triple energy potential of geopressured resources (5,6). These studies indicated that hybrid systems would be both thermodynamically and economically superior to conventional, nonhybrid geopressured power generation systems, in which the gas is separated and dispensed as pipeline natural gas. Furthermore, hybrid power plants would not require an elaborate gas processing and distribution equipment and would thus be more suitable for remote and off-shore applications.

In order more fully to characterize the performance and economic features of hybrid power plants for geopressured resources, the Electric Power Research Institute contracted UTRC to perform a detailed analytical study to assess the technical and economic feasibility of such plants. The present paper contains a summary of this study.

Geopressured Resource Characteristics In order to evaluate the influence of wellhead conditions on the design and economics of single-well hybrid power plants, two representative geopressured resources were considered. The first is the S. E. Pecan Island Prospect in Louisiana as modeled by the Southwest Research Institute (SRI) under a recent EPRI-sponsored study (3). The second resource is the Pleasant Bayou #2 well in Texas whose

* The economic analysis will be recalculated before the final report is issued.

TABLE 1

INITIAL WELLHEAD CONDITIONS

Resource	(A) S.E. Pecan Island	(B) Pleasant Bayou #2 Preliminary	Revised
Wellhead Temperature, F	300	279	279
Wellhead Pressure, psia	3300	3600	3600
Total Dissolved Solids, ppm	80,000	137,500	137,500
Brine Flow rate, 10^6 lb/hr	0.73	0.73	0.73
Noncondensable Gases (NCG), SCF/bbl	35	29	29
Lower Heating Value of NCG, Btu/SCF	900	900	755

preliminary wellhead conditions were provided to UTRC by EPRI early during the conduct of this investigation and later revised to reflect the refined EPRI estimates established on the basis of a careful assessment of available wellhead measurements. Table 1 contains a listing of the pertinent initial wellhead data for the two resources. Both the preliminary and revised data are given for the Pleasant Bayou resource. The noncondensable gases (NCG) dissolved in the S. E. Pecan Island brine were assumed to consist approximately of 90 percent methane, 5 percent ethane and higher hydrocarbons and 5 percent noncombustible gases. The lower heating value of this gas (LHV) is about 900 Btu/SCF. The same LHV was assumed for the preliminary Pleasant Bayou data. The revised Pleasant Bayou value was based on a more careful evaluation of the composition of the noncondensable gases present in actual samples taken from the well. The preliminary Pleasant Bayou data were used only for the screening of alternative hybrid power plant configurations; otherwise, the revised data were used.

The wellhead pressure and flow rate are strongly interdependent. The depletion profiles for the S. E. Pecan Island reservoir were modeled by the Southwest Research Institute (3). Because of the absence of a similar model for the Pleasant Bayou reservoir, its depletion profiles were assumed to be similar to those of the S. E. Pecan Island reservoir. Figure 1 shows these profiles for the single well production scenario. The SRI model assumes that the wellhead pressure will decrease linearly until a value of 300 psia is reached. The brine flow rate will remain constant during this phase. Subsequently, the flow rate will be allowed to decline in order to maintain a constant 300 psia wellhead pressure. The gas concentration remains essentially constant during the entire production life of the well.

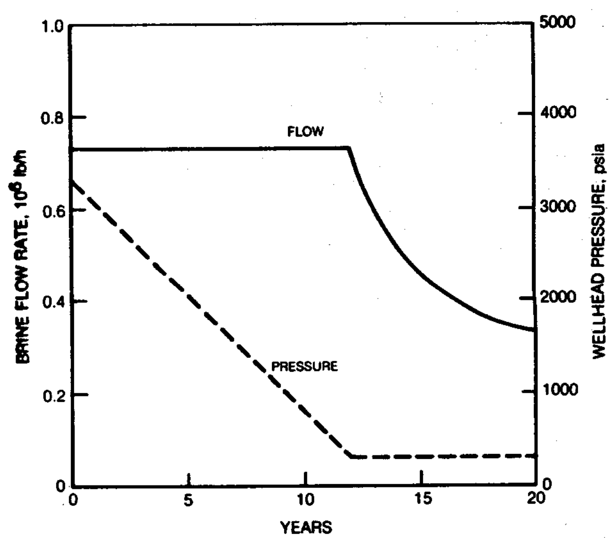

Fig. 1 Geopressured Resources Depletion Profiles

Hybrid System Configurations A simplified block diagram of a hybrid system, indicating its primary subsystems, is shown in Fig. 2. The hydraulic turbine and the gas processing facility are essentially independent of the thermal power plant. The latter consists of a topping loop comprising a combustion prime mover, and a bottoming loop comprising a vapor power plant.

In general, four basic hybrid configurations can be formed by combining a gas turbine or a gas engine in the topping loop with a flash steam system or a binary system in the bottoming loop. The waste energy rejected by the topping loop is transferred to the working fluid in the bottoming loop by means of heat exchangers interposed between the two loops. Table 2 lists possible topping/bottoming combinations and assigns designations to each.

TABLE 2

POSSIBLE TOPPING/BOTTOMING CONFIGURATIONS

Topping System		Reciprocating Gas Engine	Gas Turbine
Bottoming System	Working Fluid	System Designation	
Single-Flash	Steam	GE/F-1(S)	GT/F-1(S)
Double-Flash	Steam	GE/F-2(S)	GT/F-2(S)
Single-Pressure Binary	Steam	GE/B-1(S)	GT/B-1(S)
Single-Pressure Binary	Organic	GE/B-1(0)	GT/B-1(0)
Dual-Pressure Binary	Steam	GE/B-2(S)	GT/B-2(S)
Dual-Pressure Binary	Organic	GE/B-2(0)	GT/B-2(0)

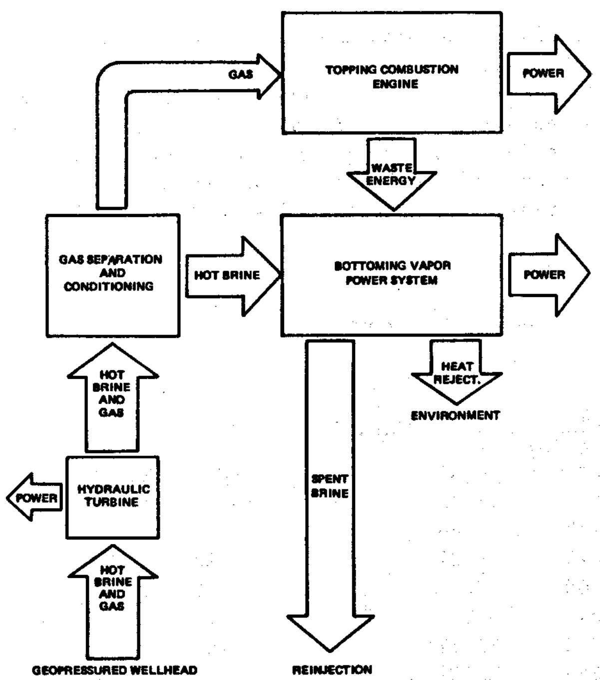

Fig. 2 Simplified Block Diagram of a Hybrid System

Hybrid Power Plant Screening A review was made of a large number of variations on the hybrid configurations listed in Table 2. Ten (10) candidate configurations were identified and subjected to a screening analysis based on preliminary thermodynamic performance and reliability criteria to select two systems for further detailed design and economic analysis. Five configurations comprised a reciprocating gas engine in the topping loop and five comprised a simple gas turbine. Combined with two sets of geopressured resource data, a total of twenty (20) system/resource cases were considered.

a) Performance The performance of each hybrid system was evaluated in terms of the resouce utilization factor, RUF, measured in Wh/lb of brine. The resource utilization factor is defined by dividing the net power output of the entire facility by the brine flow rate. Allowances were made for the parasitic and auxiliary power consumption attributed to the reinjection pumps, cooling tower fans and pumps, feed pumps, etc.

Preliminary performance and waste energy characteristics for typical gas engine and gas turbine prime movers were selected from open literature (7-9) as given in Table 3. Other screening assumptions are given in Table 4. In the case of bottoming binary systems employing organic working fluid, a cursory survey of the thermal stability and performance characteristics of a number of organic fluids led to the selection of toluene, although other fluids such as the pyridine-water azeotrope could also be employed.

TABLE 3

TYPICAL GAS ENGINE AND GAS TURBINE CHARACTERISTICS

	Gas Engine	Gas Turbine
Thermal Efficiency	0.35	0.30
Fraction of Energy in Exhaust Gas	0.28	0.70
Fraction of Energy in Jacket Water	0.23	---
Miscellaneous Energy Losses	0.14	---
Exhaust Gas Temperature, °F	∿ 1000	∿ 950

TABLE 4

BOTTOMING SYSTEM ASSUMPTIONS

Stack Temperature, °F	≥ 300
Condenser Saturation Temperature, °F	120
Vapor Turbine/Generator Efficiency	0.8
Pump/Motor Efficiency	0.8
Cooling Tower Pump Lift, ft	50
Heat Exchanger Pinch Temperature Difference, °F (Brine HX)	18
(Exhaust Gas HX)	50
Heat Exchanger Pressure Drop, %	5
Condenser Cooling Water Inlet Temperature, °F	95
Maximum Superheat Temperature, °F	
• Steam	750
• Organic Fluids	650

Tables 5 and 6 summarize the results for the S. E. Pecan Island and Pleasant Bayou resources, respectively. It can be seen that among gas engine-topped systems, configuration GE/F-2 provides the highest RUF for both resources. Among those employing gas turbine topping, configuration GT/B-2 with toluene as the working fluid offers the best performance for both resources. Nevertheless, the differences among the RUF values for many of the listed configurations are not large enough to warrant the categorical elimination of all systems other than GE/F-2 and GT/B-2 (toluene).

TABLE 5

PERFORMANCE CHARACTERISTICS OF HYBRID POWER PLANT CONFIGURATIONS
(S.E. Pecan Island)

Configuration	Working Fluid	Gross Output (kW) Hydraulic System	Topping System	Bottoming System	Total	Parasitic Power (kW)	Net Output (kW)	RUF (Wh/lb)
GE/F-1	Steam	1575	6737	3401	11713	736	10978	15.04
GE/F-2	Steam	1575	6737	4272	12584	769	11816	16.19
GE/B-1	Steam	1575	6737	3025	11337	515	10822	14.82
GE/B-2	Steam	1575	6737	3908	12220	570	11650	15.96
GE/B-2	Toluene	1575	6737	3545	11857	747	11110	15.22
GT/F-1	Steam	1575	5775	3772	11122	716	10406	14.25
GT/F-2	Steam	1575	5775	4259	11609	747	10862	14.88
GT/B-2	Steam	1575	5775	3912	11262	551	10711	14.67
GT/B-1	Toluene	1575	5775	3187	10537	610	9927	13.60
GT/B-2	Toluene	1575	5775	4785	12135	705	11430	15.66

TABLE 6

PERFORMANCE CHARACTERISTICS OF HYBRID POWER PLANT CONFIGURATIONS
(Pleasant Bayou-Preliminary)

Configuration	Working Fluid	Gross Output (kW) Hydraulic System	Topping System	Bottoming System	Total	Parasitic Power (kW)	Net Output (kW)	RUF (Wh/lb)
GE/F-1	Steam	1725	5527	2466	9718	685	9033	12.37
GE/F-2	Steam	1725	5527	3234	10486	709	9777	13.39
GE/B-1	Steam	1725	5527	1975	9227	475	8752	11.99
GE/B-2	Steam	1725	5527	2809	10270	509	9761	13.37
GE/B-2	Toluene	1725	5527	2809	10061	667	9394	12.87
GT/F-1	Steam	1725	4738	2694	9157	665	8492	11.63
GT/F-2	Steam	1725	4738	3405	9868	698	9179	12.57
GT/B-2	Steam	1725	4738	2832	9295	489	8806	12.06
GT/B-1	Toluene	1725	4738	2755	9218	565	8653	11.85
GT/B-2	Toluene	1725	4738	3756	10219	652	9567	13.11

(b) Reliability Earlier studies of geopressured resource utilization facilities indicated that the cost of production and reinjection wells, gas separation and processing equipment and other field related costs would account for as much as 85 percent of the total cost of these facilities (1-3, 5,6). Under these conditions it is important to ensure that the power generation equipment will not render idle the large capital invested in the wellfield and gas separation equipment because of reliability problems. In order to assess the relative reliability of the various power plant configurations, an index of reliability, based on the established forced and maintenance outage rates of the major power plant components, was estimated. The reliability index (RI) used for this purpose is defined by:

$$RI = [\prod_{i=1}^{N}(1-FO_i)] - MO_{max}. \qquad (1)$$

In this expression FO_i is the forced outage rate of component i and MO_{max} is the maintenance outage rate of the component requiring the longest maintenance down-time. The FO and MO factors were obtained from the extensive listing of the forced and maintenance outage rates complied by the Edison Electric Institute for a wide variety of power plant components (10).

Table 7 contains the reliability index values for various hybrid power plant configurations. It should be emphasized that the reliability index as defined by equation (1) is somewhat arbitrary and should be used only in qualitative comparisons. It is evident, however, that binary systems would be somewhat less reliable than flash systems owing to the need for periodic cleaning of the brine heat exchanger in binary systems. Also, the differences among the reliability indices of the various systems are not large enough to warrant the categorical elimination of any particular system on the basis of poor reliability alone.

The foregoing performance and reliability screening indicates that flash steam bottoming systems are a better match for gas engines and that organic binary bottoming systems are better suited to gas turbines. Therefore, gas engine-topped double-flash systems (GE/F-2) and gas turbine-topped dual-pressure toluene binary systems (GT/B-2; toluene) were selected for detailed investigations. Figures 3 and 4 contain simplified flow diagrams of the thermal power plant portion of GE/F-2 and GT/B-2 systems, respectively. Both systems consist of commercially available hardware that has been extensively used in the power and process industries.

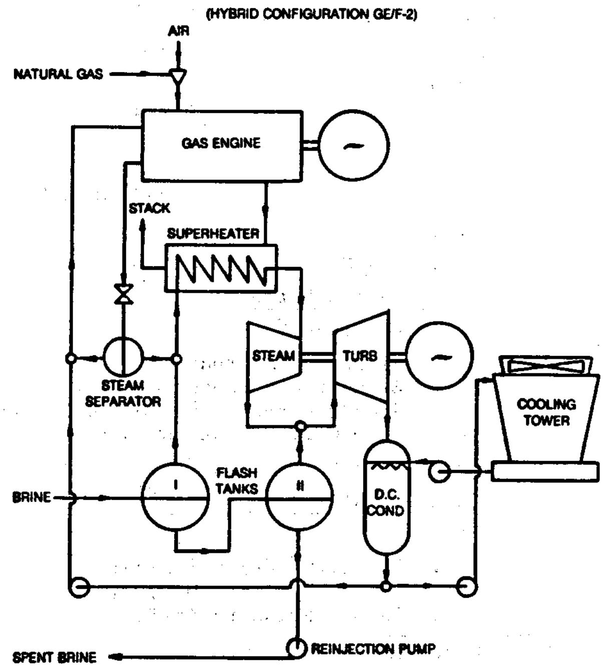

Fig. 3 Flow Diagram of a Gas Engine-Topped Double-Flash System (GE/F-2)

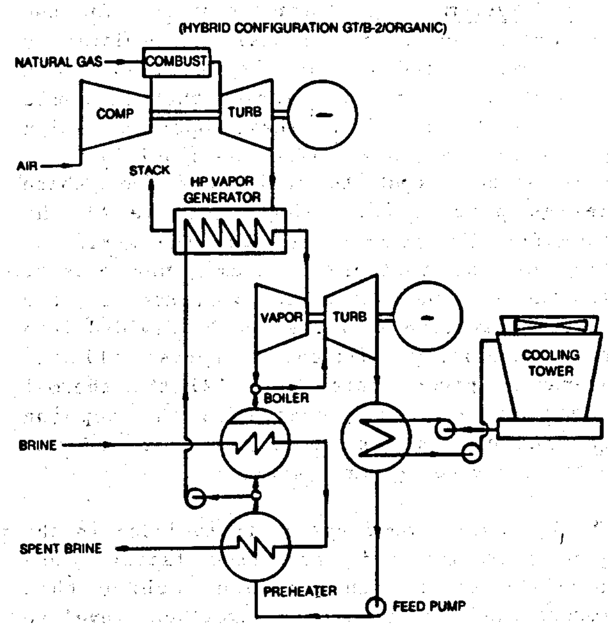

Fig. 4 Flow Diagram of a Gas Turbine-Topped Dual-Pressure Binary System (GT/B-2)

TABLE 7

OVERALL RELIABILITY INDEX

Configuration	Reliability Index
GE/F-1	0.921
GE/F-2	0.907
GE/B-1	0.899
GE/B-2	0.883
GT/F-1	0.918
GT/F-2	0.902
GT/B-1	0.896
GT/B-2	0.879

150 psia would substantially increase the moisture content of the gas with very little increase in the amount of separated methane. These machines will have to operate under high-head conditions and must be designed to tolerate the liberation of the dissolved gas and the high concentration of dissolved solids without a significant loss of efficiency or reliability.

The thermal power system receives a stream of dehydrated natural gas and another of hot, essentially gas-free brine (Figures 3,4). All the equipment in both the topping and bottoming loops are commercially available from a large number of manufacturers in the USA and abroad. Tables 8 and 9 contain summaries of the design and performance characteristics of the gas engines and gas turbines used in the design analysis. Table 10 lists the design assumptions for the remainder of the system.

TABLE 8

GAS ENGINE CHARACTERISTICS

Type	:	Turbocharged, Spark-ignition
Speed, RPM	:	∿ 400-600
Compression Ratio	:	∿ 8.25:1
Energy Balance*		
. Electrical Output	:	0.36
. Exhaust Gas Energy	:	0.28
. Jacket Water & Charge Air Energy	:	0.18
. Lube Oil, Radiation, Unaccounted	:	0.18
Exhaust Temperature, °F	:	915
Jacket Water Temperature**, °F	:	180-200
Fuel	:	Natural Gas#
. LHV (Btu/SCF) - Typical	:	900
- Minimum	:	600
. Supply Pressure (psig)	:	50

*Based on LHV of fuel gas

** Higher jacket water temperatures and ebullient cooling would necessitate some design modifications

Gas should be free of liquid hydrocarbons

Hybrid System Design Characteristics The two systems selected on the basis of preliminary performance and reliability criteria were subjected to a parametric thermodynamic analysis to determine their optimum design parameters and to estimate the sensitivity of the system output to deviations from these design parameters. The objective of the thermodynamic optimization was the maximization of the bottoming system power output. Insofar as power generation is concerned, the power generation facility can be divided into two essentially independent parts: (1) the hydraulic power system, and (2) the thermal power system which comprises the topping gas-fueled combustion prime mover and the bottoming vapor power system.

The hydraulic power system is included in the gas separation and processing facility and consists of a high-pressure turbine that lowers the pressure from its wellhead level to about 1000 psia and a low-pressure turbine which lowers the pressure from 1000 to 150 psia. Reduction of the pressure much below

TABLE 9

GAS TURBINE CHARACTERISTICS

Type	:	Simple-cycle
Pressure ratio	:	∿ 12-14:1
Energy Balance*#		
. Electrical Output	:	0.30
. Exhaust Gas Energy	:	0.70
Exhaust Temperature, °F	:	1050
Fuel	:	Natural Gas
. LHV (Btu/SCF) - Typical	:	900
- Minimum	:	550
. Supply Pressure (psig)	:	150-250

*Based on LHV of fuel gas.

Lubricating oil and radiation energy losses are very small.

TABLE 10

DESIGN ASSUMPTIONS*

	Design Value
Wet-bulb Temperature, °F	80
Condenser Terminal Temperature Difference, °F	
. Flash Systems (Direct Contact Condenser)	2 (subcooling)
. Binary Systems (Surface Condenser)	7
Minimum Temperature Difference, °F	
. Brine Heat Exchangers	10
. Exhaust Gas Heat Exchangers	50
Overall Hydraulic Turbine/Generator Efficiency, %	80
Reinjection Pressure, psia	600

*See Table 4 for additional assumptions

The most significant parameters that affect the output of flash and binary systems are the flash and boiling pressures, respectively. Figures 5 and 6 depict the influence of these parameters on the gross output of the bottoming system for the S. E. Pecan Island resource. Similar trends were observed for the Pleasant Bayou resource. These results were employed to select the flash and boiling pressures corresponding to peak output. Table 11 summarizes the power ratings for the various power generation subsystems of GE/F-2 and GT/B-2 systems for both S. E. Pecan Island and Pleasant Bayou #2 resources. The auxiliary and parasitic power consumption are also listed as well as the resource utilization factor.

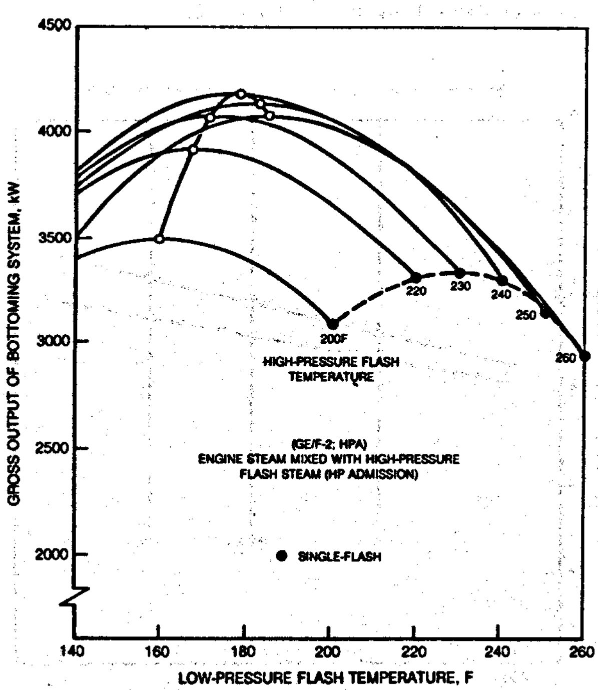

Fig. 5 Gross Output of the Bottoming System in GE/F-2 Plants

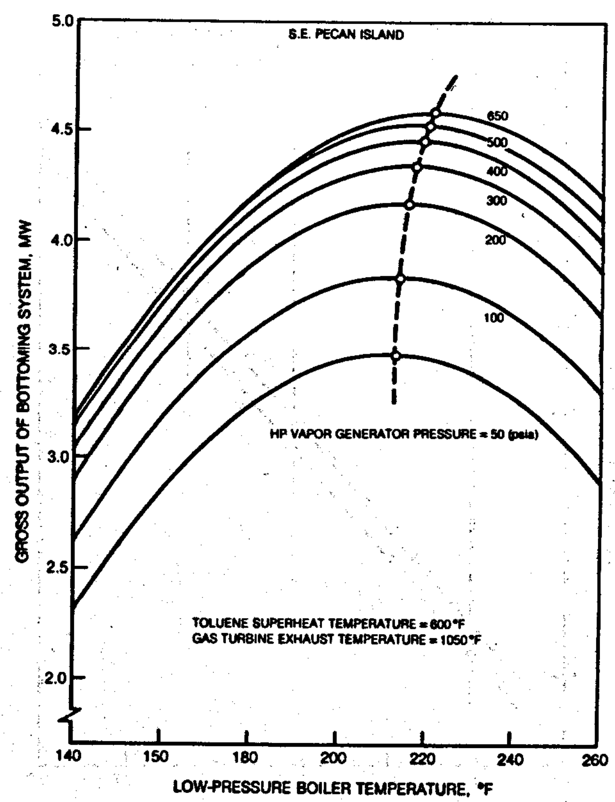

Fig. 6 Gross Output of the Bottoming System in GE/B-2 Plants

TABLE 11

SUMMARY OF POWER RATINGS

Resource	S.E. Pecan Island		Pleasant Bayou #2	
System Designation	GE/F-2	GT/B-2	GE/F-2	GT/B-2
(1) Output Power, kW				
. HP Hydraulic Turbine	1150	1150	1300	1300
. LP Hydraulic Turbine	425	425	425	425
. Gas Engine or Gas Turbine	6930	5775	4815	4015
. HP Steam (Toluene) Turbine	1745	(1995)	1190	(1415)
. LP Steam (Toluene) Turbine	2435	(2685)	1690	(1825)
Gross Power Output, kW	12685	12030	9420	8980
(2) Auxiliary and Parasitic Power, kW				
. Reinjection Pumps	425	345	420	325
. Cooling Water Pumps	130	225	110	170
. Cooling Tower Fans	70	95	60	70
. Feed Pumps & Miscellaneous	10	120	10	80
. Condenser Gas Extraction System	120	25	120	20
Total Power Consumption, kW	755	810	710	665
(3) Net Power Output, kW	11930	11220	8700	8315
(4) Resource Utilization Factor, Wh/lb	16.35	15.37	11.92	11.39

Sensitivity to Wellhead Conditions Owing to the relatively high uncertainty associated with geopressured resources, a study was undertaken to assess the effect of gas content and wellhead temperature on the power output of hybrid power plants. The results of this study are depicted in Figs. 7 and 8. The gas content is expressed in terms of an equivalent production of a nominal natural gas whose LHV is 900 Btu/SCF. It can be seen that the power output is strongly dependent on the gas content but only weakly dependent on wellhead temperature. The points shown in Figs. 7 and 8 represent the alternative wellhead data listed in Table 12.

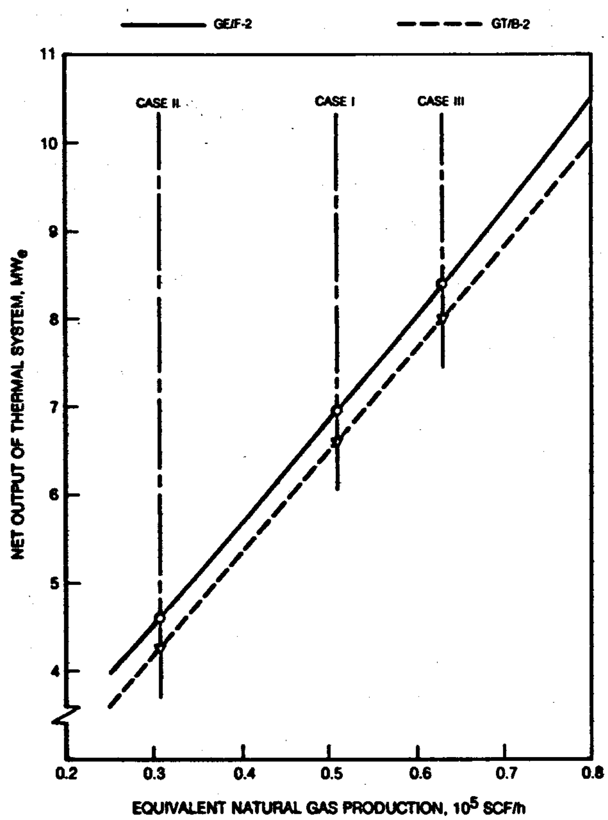

Fig. 7 Effect of Gas Production Rate on Output

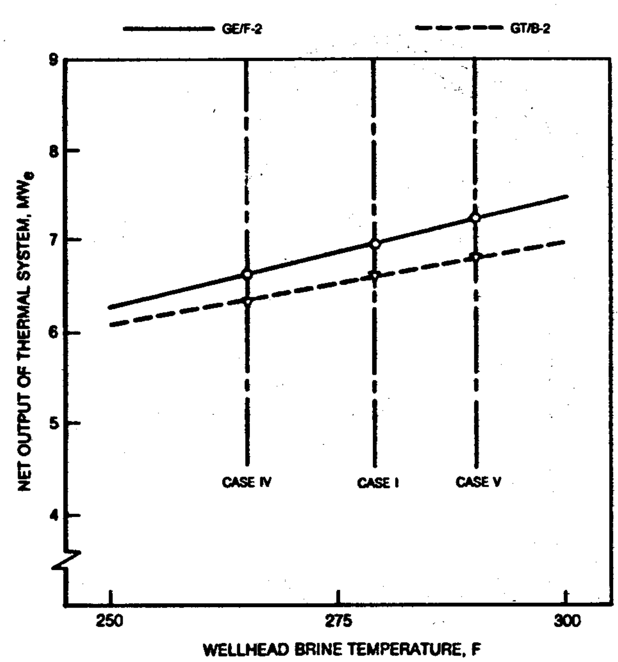

Fig. 8 Effect of Wellhead Temperature on Output

TABLE 12

ALTERNATIVE WELLHEAD DATA #
(Pleasant Bayou)

Case	I	II	III	IV	V
Flow Rate, 10^6 lb/h	0.73	0.73	0.73	0.73	0.73
Pressure, psia	3600	3600	3600	3600	3600
TDS, ppm	137,500	137,500	137,500	137,500	137,500
Temperature, °F	279	279	279	265	290
NCG Content, SCF/bbl	29	19	35	29	29
. HP Gas*, SCF/bbl	22	12	28	22	22
. LP Gas*, SCF/bbl	7	7	7	7	7
Average LHV, Btu/SCF	755	697	774	755	755
Equivalent Gas Production, SCF/h	50740	30690	62780	50740	50740

Data provided to UTRC by EPRI

* LHV of HP Gas = 866 Btu/SCF and of LP Gas = 406 Btu/SCF

Hybrid Power Plant Sizing and Costing The capital and operating costs of an installation consist of design and construction costs, capital charges, and operation and maintenance expenses. For the purpose of costing, the entire installation was divided into (1) the fuel supply facility which includes the production and reinjection wells and associated equipment, (2) the fuel processing facility which includes the gas separation and conditioning equipment, and (3) the power plant proper which includes both hydraulic and thermal power systems.

The design and construction costs comprise the installed cost of the entire system, including both direct and indirect field costs and contingencies. These data were estimated after the pertinent sizing parameters of each of the major components had been specified. The capital cost of the fuel supply facility was taken from Reference (3). An annual inflation rate of 13 percent was introduced to adjust the Reference (3) values from third-quarter 1979 to mid 1980 dollars. The design and construction costs also include the cost of general facilities such as general piping and instrumentation, civil and structural work, on-site electric distribution systems, safety and fire protection systems, laboratories, etc.

Two types of contingency factor were employed: a module or process contingency to account for the uncertainty in the design, performance and cost of unproven pieces of hardware; and a project contingency which accounts for the cost of additional equipment costs that may result from a more detailed design of a definitive site-specific project, as well as unforeseen cost increases during plant construction. A project contingency factor of 15 percent was assumed in this study. A module contingency factor of 10 percent was added to the cost of the hydraulic turbine to account for the uncertainty associated with the effect of the liberation of dissolved gas inside the machine.

The capital changes consist of prepaid royalties, preproduction costs, working capital, initial fluids and chemicals cost, land and allowance for funds during construction (AFDC). These items were estimated in accordance with EPRI recommendations.

The operation and maintenance expenses were also estimated in accordance with EPRI recommendations and include both fixed and variable costs, the first of which comprises both operating and maintenance labor and maintenance materials.

Table 13 contains a summary of the cost data for GE/F-2 and GT/B-2 systems at both the S. E. Pecan Island and Pleasant Bayou resources. It can be seen that the difference between the two resouces has the strongest impact on cost

TABLE 13

SUMMARY OF HYBRID POWER PLANT TOTAL CAPITAL AND OPERATING COSTS
($1000 - Mid 1980)

Resource Configuration	S.E. Pecan Island (GE/F-2)	S.E. Pecan Island (GT/B-2)	Pleasant Bayou #2 (GE/F-2)	Pleasant Bayou #2 (GT/B-2)
Capital Cost				
. Design & Construction	25552	25056	23613	23193
. Capital Charges	2717	2704	2553	2535
Total Capital Cost	28269	27760	26166	25728
Annual O&M Cost				
. Fixed	992	967	950	919
. Variable	46	82	32	63
Construction Period (years)	2	2	2	2
Investment Dispersion				
. First year	5146	5319	4907	5007
. Second year	20406	19737	18706	18186
Installed Power (kW)				
. Hydraulic	1575	1575	1725	1725
. Thermal	10355	9645	6975	6590
Total Installed Power	11930	11220	8700	8315
Unit Installed Cost ($/kW)	2370	2474	3008	3094

per kW; the difference between GE/F-2 and GT/B-2 systems at the same site is relatively small.

Economic Evaluation The levelized cost of electricity produced by hybrid power plants was computed in accordance with the Revenue Requirement methodology described in the EPRI Technical Assessment Guide (11). The assumptions used for determining the levelized fixed charge rate are given in Table 14. These values are identical with the values given in Reference (11) for an annual inflation rate of 6 percent and lead to a levelized fixed charge rate of 14.74 percent, allowing for a 10 percent investment tax credit and accelerated depreciation.

A levelized capacity factor of 85 percent was assumed for all the plants. However, because the net output of the power plant will decline over its lifetime due to reservoir depletion, the economic analysis was based on a levelized plant output that takes into account both the levelized capacity factor and the effect of depletion. The levelized cost of electricity was computed by dividing the levelized annual capital and operating costs by the levelized annual output kilowatt hours. Figure 9 contains a comparison of the levelized cost of electricity for four hybrid power plant cases, indicating the capital and operating cost contributions for each. Figure 10 depicts the same comparison expressed in terms of inflation-independent levelized cost (12).

TABLE 14

ASSUMPTIONS FOR LEVELIZED FIXED CHARGE RATE

Debt Ratio	50.0%
Annual Debt Cost	8.0%
Preferred Stock Ratio	15.0%
Annual Preferred Stock Cost	8.5%
Common Stock Ratio	35.0%
Annual Common Stock Cost	13.5%
Annual Weighted Cost of Capital	10.0%
Federal and State Income Tax Rate	50.0%
Property Taxes and Insurance	2.0%
Investment Tax Credit	10.0%
Facility Life (years)	20
Retirement Dispersion Allowance	0.67%

Economic Comparisons In order meaningfully to compare hybrid power plants with their conventional counterparts, the revenue that would be

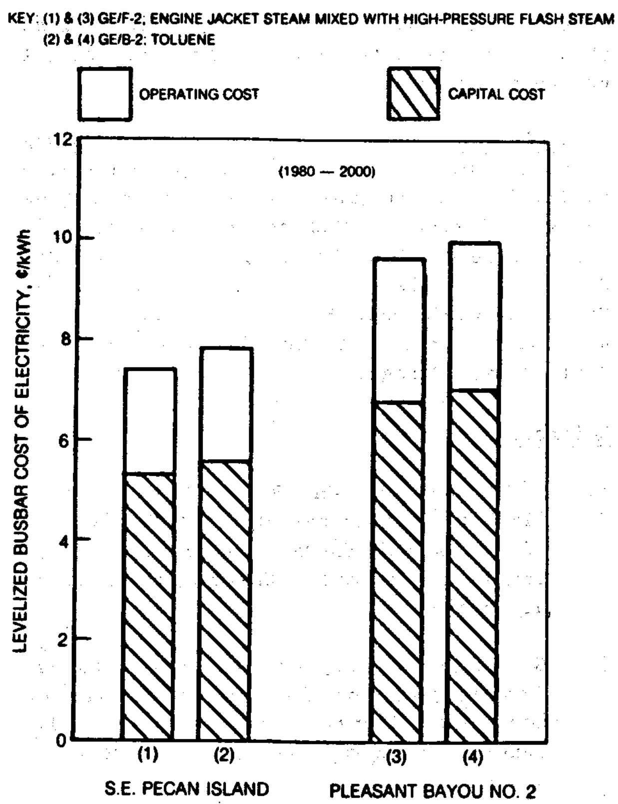

Fig. 9 Levelized Cost of Electricity Expressed in Current Dollars

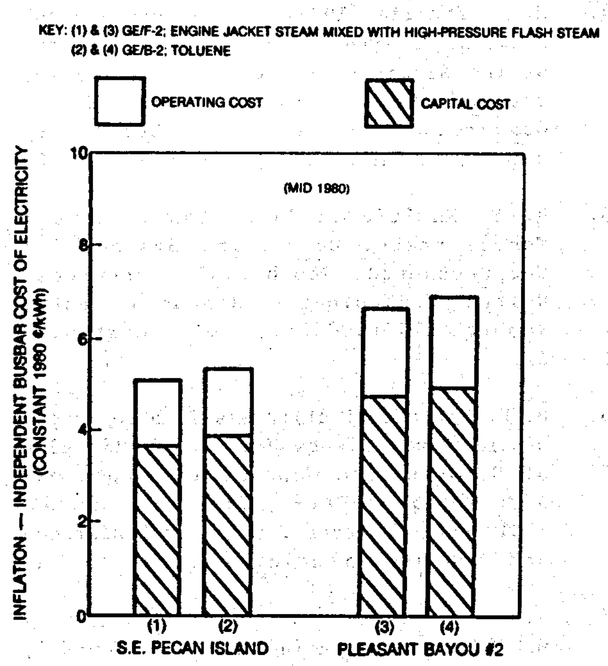

Fig. 10 Levelized Cost of Electricity Expressed in Inflation-Independent Dollars

obtained from the sale of natural gas in the conventional case must be realistically estimated. Insofar as the economic feasibility of geopressured energy developments is concerned, it is only necessary to require that the revenue from the sale of natural gas and electricity must be sufficient to recover all the capital and operating expenses of the entire facility, including a reasonable return on investment. It does not matter how much of this revenue is derived from the sale of gas and how much is derived from the sale of electricity. The partitioning of the revenue will depend ultimately on the market value of each of the output commodities over the lifetime of the installation. For these reasons, it is rather arbitrary to estimate the cost of electricity by assuming that methane-free brine will be supplied to the power plant as a free by-product of the gas separation and conditioning process as was done in Reference (3). Figure 11 contains parametric comparison between the levelized cost of electricity produced by hybrid and conventional plants at the S. E. Pecan Island resource in which the levelized price of natural gas was treated as a parameter. The cost and performance data for the conventional plants were obtained from Reference (3). It can be seen that hybrid plants remain superior to conventional plants over a wide range of gas prices.

Wellhead natural gas prices vary widely from one location to another and are subject to Federal regulations and still-existing long-term contracts. The future prices of wellhead

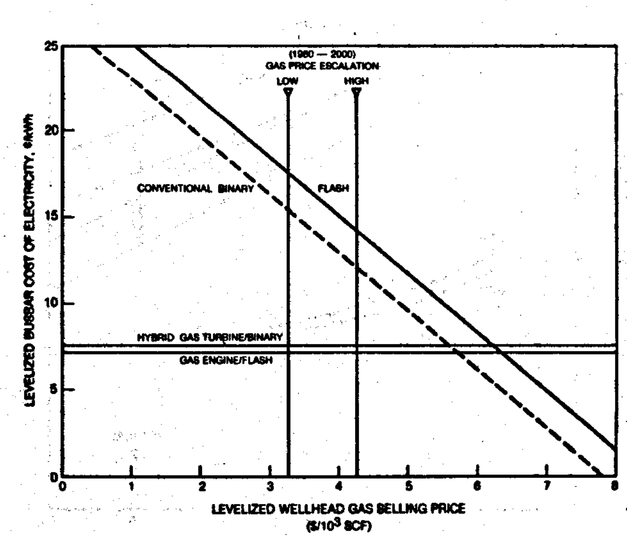

Fig. 11 Comparison of Hybrid and Conventional Plants

natural gas are not known with reasonable certainty, although the general consensus is that they will experience real escalation until they become competitive with alternative fuels such as oil and coal-derived liquid and gaseous fuels. Nevertheless, the historical escalation of natural gas prices has been amply documented (13). Future gas price escalation scenarios have been developed by DOE and other organizations. According to recent DOE macroeconomic models (14), the average price of natural gas, which amounted to $\$1.37/10^3$ SCF at the wellhead in mid 1980 (13), would escalate at an annual real rate of 12 percent until 1985 followed by a milder 4.6 percent rate from 1985 to 1990 and 4.0 percent afterwards. The same source also provides data on a lower escalation scenario. The levelized wellhead price of natural gas as computed by both the high and low escalation scenarios is marked on Figure 11. Figure 12 presents a comparison of hybrid and conventional plants over a range of single-well gas production rates. In this comparison, the wellhead temperature, pressure and flow rate as well as the depletion profiles are similar to those of S. E. Pecan Island. It is evident that hybrid power plants would be far superior to their conventional counterparts. The levelized cost of electricity produced by the

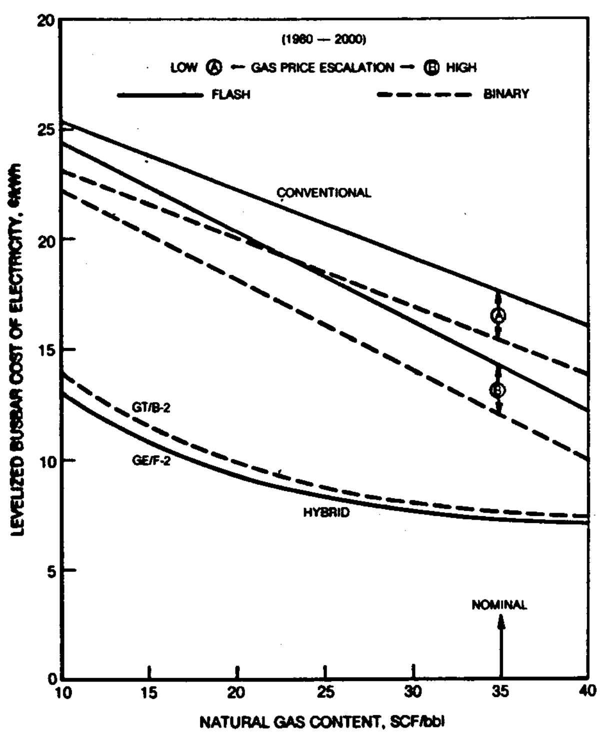

Fig. 12 Effect of Gas Production Rate on the Levelized Cost of Electricity

hybrid plant would be 40-50 percent lower than that of electricity produced by conventional geopressured power plants.

Acknowledgement The work described herein was performed by the Advanced Energy Conversion System Group at the United Technologies Research Center. UTRC contributors to this effort were Dr. R.W. Bass, Mr. F.R. Biancardi, Dr. H. E. Khalifa (Principal Investigator), Mr. A. M. Landerman, Dr. T. N. Obee and Mr. B. W. Rhodes. Mrs. Meredith J. Angwin was the EPRI Project Manager.

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ASSESSMENT OF ADVANCED GEOTHERMAL ENERGY CONCEPTS

Contract No. RP1673-1

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A number of advanced concepts have been proposed for converting geothermal energy to electricity. Many of these concepts are claimed to have advantages over conventional binary and flashed steam cycles. These claimed advantages include higher efficiency, lower cost, higher resource utilization, and better reliability. Some of these concepts have only been explored on paper, while others have been tested in field operation. Some are said to be suitable for a wide range of geothermal resources, while others are aimed at special needs. The purpose of this study was to analyze concepts that have been proposed for hydrothermal resource utilization, and to compare them with conventional steam flash and binary systems and with each other.

The evaluation of the concepts began with a literature survey, followed by discussions with inventors and proponents. The information obtained included efficiency data (both measured and predicted), development status, research and development spending, date of expected commercial availability, resource applicability, and estimated cost. The advantages and disadvantages of each concept, both technical and economic, were evaluated to give applicabilities of the concepts from a common method of analysis.

The concepts analyzed included variations of the binary and flashed steam cycles, fossil/geothermal and solar/geothermal hybrids, total flow devices, (Biphase rotary separator turbine, helical expander, bladeless turbine, LLL impulse turbine, LLL reaction turbine, Elliott turbine and Horst expander) and four other concepts; thermoelectric, mist lift, shape memory effect alloy engines and the Ericsson cycle. None of these last four cycles appear attractive at this time, when compared to conventional systems.

Several of the total flow devices appear to improve the efficiency of steam flash systems by replacing the conventional flash tanks. These devices may also have limited utility as non-condensing wellhead generating units.

The Sperry gravity-head system potentially gives the highest efficiency of all the concepts. This system is a modified binary cycle with the primary heat exchanger inside the well. The working fluid circulating pump is eliminated, since a thermosiphon effect is created in the downhole tubing. The gravity-head system savings must overcome the problems of having equipment in the well.

A detailed economic analysis was made of the Biphase rotary separator turbine (RST). Quantitative comparisons were made between geothermal power processes employing rotary separator turbines and single stage steam flash, two stage steam flash, and binary processes. Single and two stage steam flash processes using RST's in place of flash vessels were chosen for the RST processes. Two typical geothermal resources were investigated; a 360°F non-scaling moderate temperature resource (MTR), and a 507°F non-scaling high temperature resource (HTR). Wellhead and 50 MWe plant size designs were developed for each of the process-resource combinations, resulting in a total of 20 cases. Field and plant capital costs and levelized bus bar power costs were estimated for each case.

Brine usages for the RST processes were consistently lower than the corresponding flashed steam processes. At the MTR, the binary process was, however, still lower. At the HTR brine usage for the RST processes is lower than for the other processes.

Estimated bus bar costs for single stage flash plants are consistently higher than those for the other plants for a given resource and plant size. At the MTR the bus bar costs for binary are significantly lower than the others. The advantage is the result of the lower brine requirements for the binary process, reflected in lower fuel costs.

At the HTR all processes use flashed steam as a heat source and the bus bar costs, except for single stage flash, are close to one another. The binary plant shows the lowest cost for 50 MWe plants at 65 mills/kWh. The significantly lower brine requirements and fuel costs for the RST processes have been offset by higher capital costs.

The RST processes use the concept of employing a power producing isentropic flash in place of the isenthalpic flash used in flashed steam plants. The thermodynamic concept is sound and actual improvements in brine utilization have been demonstrated in field tests. System reliability for extended runs has not yet been demonstrated.

COMPARISONS OF ADVANCED POWER CONVERSION CONCEPTS

(from vugraphs shown at conference)

PROJECT OBJECTIVES

- Identify and describe conversion concepts
- Determine technical and economic advantages and disadvantages
- Compare concepts with conventional cycles and with each other
- Perform detailed economic analysis of Biphase rotary separator turbine (RST)
  - Analyze for medium and high temperature resources and for wellhead and central plant applications
  - Compare to single and dual stage flashed steam plants and to binary cycles
  - Analyze both single and dual stage RST cycles.

CRITERIA FOR COMPARING ADVANCED POWER CYCLES

Technical:

- Machine Efficiency
- Brine Utilization
- Complexity
- Resource Applicability
- Size Limitations
- R&D Status

Economic:

- Capital Cost
- Power Cost
- Availability

SELECTION OF CONCEPTS

- We included all concepts that have been actively promoted for geothermal applications
- The concepts fit into several categories:
  - Flashed Steam
  - Binary Cycles
  - Hybrids
  - Total Flow Devices
  - Others (mostly developed for other energy sources)

METHODS OF EVALUATION

- Literature survey
- Discussions with inventors and proponents
- Technical analysis
- Economic analysis
- Comparison with other concepts

CONCEPTS STUDIED

Flashed Steam	Single Stage Two Stage
Binary	Standard Flash Dual Cycle Direct Contact Gravity Head
Hybrid	Fossil Solar Combined
Total Flow	Bladeless Turbine LLL Impulse Turbine LLL Reaction Turbine Biphase RST-1 Stage Elliott Turbine Helical Expander Horst Expander
Thermoelectric	
Mist Lift	
Shape Memory Effect	
Ericsson Cycle	

EVALUATION OF ADVANCED CYCLES

- Flashed steam and standard binary systems were used as a basis for comparison with other systems.
- Flash binary was demonstrated at the GLEF. Although less efficient than pure binary, the process can be used in a scaling environment.
- Direct contact binary cycles show promise of lower capital costs than standard binary and progress has been made in solving the problem of working fluid loss in the spent brine and contamination of the working fluid with non-condensable gas.
- Two modifications of the dual binary cycle are employed at Raft River and East Mesa. Neither

has been demonstrated as yet. Both offer potential improvements in brine utilization as compared to standard binary.

- The Sperry gravity head system shows theoretical performance to be the best of all systems studied. Solutions to the problems of having equipment in the well have not been demonstrated.

- Hybrid systems employ the combustion of fossil fuels and biomass augmented by geothermal heat to generate electricity. These systems are essentially state of the art, but none have yet been built.

- Two of the total flow devices (helical screw expander and rotary separator turbine) have been tested on a significant scale and show promise for replacement of flash tanks in steam flash plants as well as use for non-condensing wellhead generating units.

- Thermoelectric, mist lift, shape memory effect and Ericsson cycles require extensive development.

(see Table I)

- - - - - - - - - - -

CAPITAL COSTS ESTIMATES METHODOLOGY

- Prepare process flow diagram
- Size and rate major equipment
- Estimate major equipment costs from vendor quotations and in-house records (mid-80 basis)
- Apply installation factors to major equipment costs to arrive at installed costs
- Apply sales tax
- Add 20 percent for contractor's fee and contingency

BASELINE CASES FOR RST STUDY

Processes

- Single-stage steam flash
- Two-stage steam flash
- Binary

Resources

- Heber Medium temperature (360°F)
  Low non-condensables (50 ppm)
  Low salinity (14,000 ppm)
  Non-scaling

- Brawley High temperature (507°F)
  High non-condensables (2.7% w)
  High salinity (10.5% w)
  Non-scaling in plant (assumption)
  Spent brine treatment provided

Plant Sizes

- 50 MWe central plant

- Wellhead generating plant
  Heber self-flowing wells flow at 5000,000#/hr
  Heber pumped wells flow at 650,000#/hr
  Brawley wells flow at 450,000#/hr

LEVELIZED FUEL COST ASSUMPTIONS

- Private sector developer owns and operates field, selling heat energy to investor-owned utility.
- 20 percent DCF rate of return to developer.
- Intangible drilling expense = 70 percent of the cost of production wells.
- Working capital = one month's operating and maintenance cost.
- Sum of the digits depreciation.
- 10 percent investment tax credit.
- New wells drilled during the life of the project = number of original wells.
- Project life = 30 years.
- O&M costs escalated at 6 percent per year.
- Property taxes = 6 percent of revenues.
- Royalty payments = 10 percent of revenues.
- 15 percent depletion allowance.

LEVELIZED CONVERSION COST ASSUMPTIONS

- Power plant owned and operated by investor-owned utility.
- Based on 1979 edition of EPRI Technical Assessment Guide
- Interest on Capital (MAR) = $\frac{\%}{10}$
- Interest on Loan = 8
- Debt/Total Capital = 50
- Property Tax Rate = 1
- Insurance Rate = 1
- Investment Tax Credit = 10
- Capacity Factor = 80
- O&M costs escalate at 6 percent per year.

HEBER 50 MW

	SINGLE FLASH	DUAL FLASH	BINARY	RST SF	RST DF
Plant Capital 10^6 \$	37.1	37.4	43.1	46.5	64.0
Power mills/kWh					
Plant	26	26	28	30	37
Fuel	53	39	26	42	35
Total	79	65	54	72	72
Brine lbs/kWh	263	196	154	211	180

HEBER WELLHEAD

	SINGLE FLASH	DUAL FLASH	BINARY	RST SF	RST DF
Plant Capital 10^6\$	3.6	5.5	6.0	5.0	8.3
Power mills/kWh					
Plant	121	105	66	110	117
Fuel	77	57	37	61	53
Total	198	162	103	171	170
Brine lbs/kWh	263	196	154	211	180

BRAWLEY 50 MW

	SINGLE FLASH	DUAL FLASH	BINARY	RST SF	RST DF
Plant Capital 10^6\$	47.5	54.4	39.1	47.6	59.8
Power mills/kWh					
Plant	30	33	27	30	35
Fuel	51	38	38	38	36
Total	81	71	65	68	71
Brine lbs/kWh	119	87	92	90	75

BRAWLEY WELLHEAD

	SINGLE FLASH	DUAL FLASH	BINARY	RST SF	RST DF
Plant Capital $10^6\$$	6.8	10.2	6.6	8.5	13.4
Power mills/kWh					
Plant	78	71	59	66	72
Fuel	91	67	71	70	58
Total	169	138	130	136	130
Brine lbs/kWh	119	87	92	90	75

CONCLUSIONS

- Installation of RST units in place of throttling valve and flash tank improves performance of steam flash cycles at Heber and Brawley.
- Brine consumption is down, capital investment is up, and bus bar costs are down as compared to steam flash cycles at Heber and Brawley.
- Bus bar energy costs for binary system are lower (in one case equal) than either steam flash or RST systems.
- The tests planned at Roosevelt Hot Springs later this year should validate RST designs.
- Important to remember that all of the Brawley cases assume no scaling in plant equipment.

Table I

SUMMARY COMPARISON

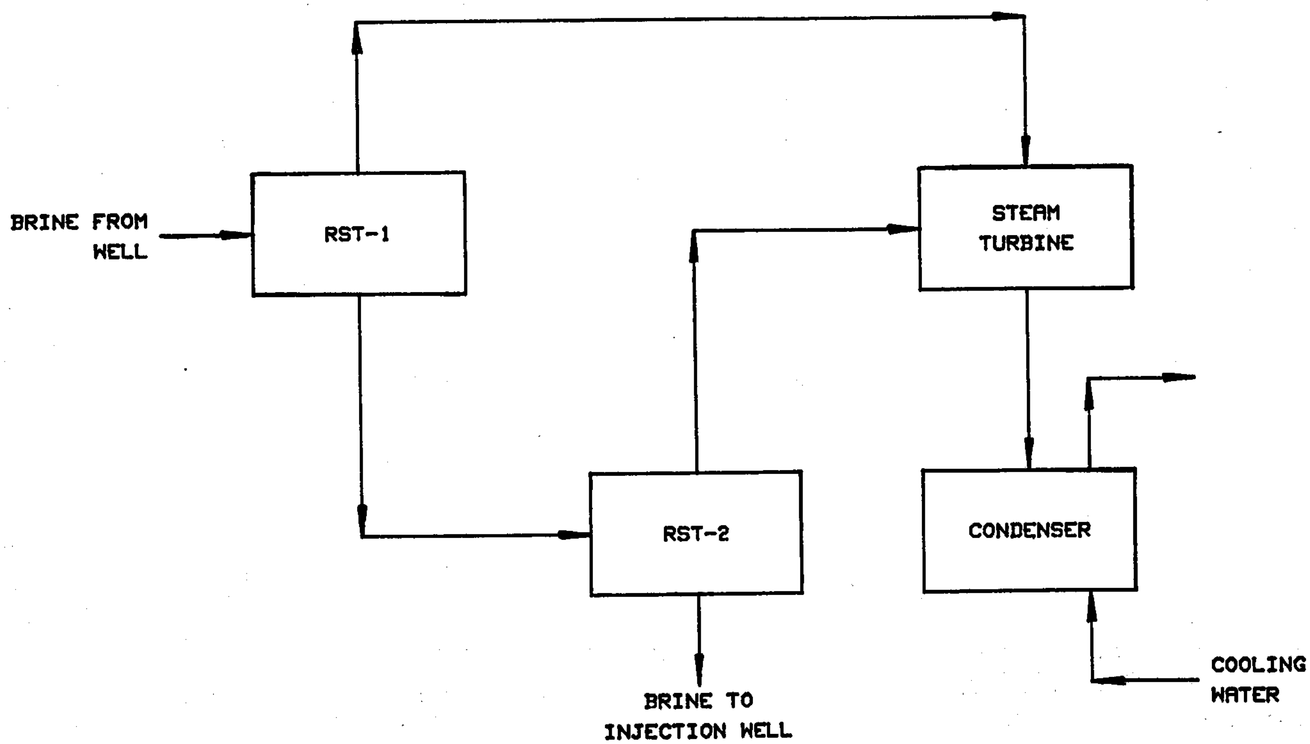
Concept	Efficiency		Complexity	R and D Status				Cost (3)		Resource				Applicability		
	Brine Util. (1)	Machine %	L=low (2) M=medium H=high	Paper Study	Lab Test	Field Tests	Commer. or Ready	Plant	Power	Suitable: Y=Yes, N=No <150°C	>150°C	Scaling	Geo-Pressured	Well Head	Central Plant	Element of Cent. Plant
Flashed Steam																
Single Stage	.59	-	L	X	X	X	C	.86	1.92	N	Y	Y	Y	Y	Y	-
Two Stage	.79	-	L	X	X	X	C	.87	1.57	N	Y	Y	Y	Y	Y	-
Binary																
Standard	1.00	-	M	X	X	X	C	1.00	1.00	Y	Y	N	Y	Y	Y	-
Flash	-	-	M	X	X	X	R	-	-	N	Y	Y	Y	Y	Y	-
Dual Cycle	-	-	H	X	X	X	-	-	-	Y	Y	N	N	Y	Y	-
Direct Contact	.73	-	M	X	X	X	-	-	1.08	Y	Y	Y	N	Y	Y	-
Gravity Head	1.15	-	M	X	X	X	-	-	0.87	Y	Y	N	N	Y	Y	-
Hybrid																
Fossil	17.0	-	M	X	-	-	-	-	0.90	Y	Y	Y	Y	Y	Y	-
Solar	-	-	M	X	-	-	-	-	-	Y	Y	Y	Y	Y	Y	-
Combined	-	-	M	X	-	-	-	-	-	N	N	N	Y	Y	Y	-
Total Flow																
Bladeless Turbine	.68	.54	L	X	X	-	-	.76	1.01	Y	Y	N	N	Y	Y	-
LLL Impulse Turbine	.57	.45	L	X	X	-	-	-	-	Y	Y	N	N	Y	Y	-
LLL Reaction Turbine	.51	.40	M	X	X	-	-	-	-	Y	Y	N	Y	Y	N	Y
Biphase RST-1 Stage	.73	.50	M	X	X	X	R	1.08	1.33	N	Y	N	N	Y	N	Y
Elliott Turbine	.73	.50	L	X	X	-	-	-	1.33	N	Y	N	N	Y	Y	-
Helical Expander	.63	.50	M	X	X	X	R	.53	.91	Y	Y	Y	Y	Y	N	Y
Horst Expander	.58	.46	H	X	X	-	-	.59	1.00	Y	Y	Y	Y	Y	N	Y
Thermoelectric	.50	-	M	X	-	-	-	2.81	2.50	Y	Y	N	N	Y	Y	-
Mist Lift	-	-	M	X	X	-	-	-	-	Y	N	Y	N	Y	Y	-
Shape Memory Effect	.17	-	M	X	X	-	-	2.11	3.50	Y	Y	Y	N	Y	Y	-
Ericsson Cycle	-	-	H	X	-	-	-	-	-	Y	Y	N	N	Y	Y	-

(1) Brine utilization efficiency is the ratio of power per unit brine for the concept divided by power per unit brine for a standard binary cycle. The resource chosen was Heber, see reference (9) of section 3.

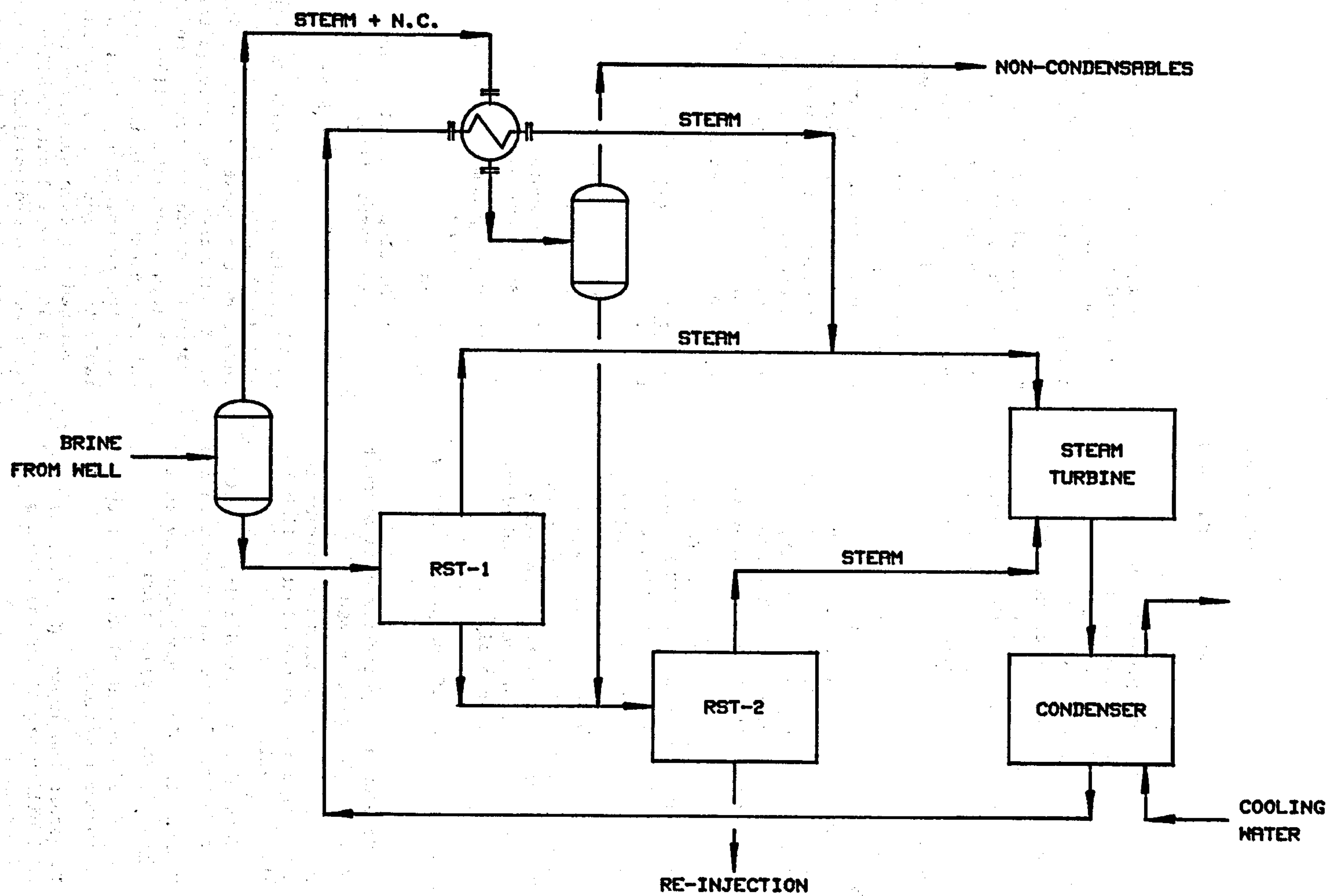
(2) Compared to a standard binary cycle.

(3) Relative costs: the ratio of the cost for the concept divided by the cost for a standard binary, assuming a 50 MWe net plant at Heber, see reference (9) of section 3.

<u>HEBER RST - TWO STAGE</u>



BRAWLEY 2-STAGE RST



RELIABILITY AND AVAILABILITY OF HEBER BINARY PLANT

EPRI Contract RP 1900-2

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Introduction This paper presents the results of an adaptation and application of a reliability and availability assessment methodology to the Heber Binary Plant. The assessment methodology was developed under EPRI Contract RP 1461; it has been applied previously to gasification combined-cycle (GCC) and advanced coal-fired plant (CFP) designs, as well as a number of operational oil-fired and gas-fired combined-cycle plants.

A factor essential to the economic viability of the binary geothermal concept is that the planned demonstration plant achieve a high level of availability. Further, it has been shown that reliability and availability are quantifiable design parameters that should be addressed throughout the design and development phase to ensure that a system's economic and performance goals are realized. For these reasons, EPRI contracted with ARINC Research Corporation (1) to adapt its assessment methodology to the Heber design so that initial baseline estimates of the plant reliability and availability could be obtained, and (2) to develop an operating model that could be used in evaluating design alternatives and obtaining updated assessments of the expected plant performance as the design evolves.

The specific objectives of the project are as follows:

- To develop a computer-based assessment model of the Heber design
- To exercise the model to obtain baseline estimates of the plant reliability and availability
- To determine the sensitivity of the baseline results to data uncertainties
- To rank the plant components by their effect on the baseline results
- To identify potential availability improvement options
- To assess the impact of potential reliability growth on the plant's performance

Plant Description The assessment model was based on the design illustrated in the *Preliminary Design Manual for a Geothermal Demonstration Plant at Heber, California* (Ref. 1). This design uses the binary cycle (geothermal brine/hydrocarbon mixture) to develop 50 MWe of output power from the moderate temperature brine of the Heber geothermal anomaly.

The geothermal brine is pumped from the anomaly to the plant, where its thermal energy is transferred to the secondary hydrocarbon fluid, which is then used to drive a turbine/generator set to produce electric power. The primary fluid is then returned and reinjected to the anomaly; and the hydrocarbon fluid is cooled, condensed, accumulated, and returned to the heat exchanger. The plant design consists of seven independent subsystems, summarized in Table 1 and shown schematically in Figure 1. Future plans call for the addition of one heat exchanger, one hydrocarbon condenser, and three cooling fan modules.

Technical Approach The study consisted of six tasks:

- Characterize the plant design and equipment
- Define system states, fault trees, and state definitions
- Develop component failure and repair data base
- Adapt and apply the assessment model
- Develop reliability growth estimates and assess their impact
- Prepare final report

On the basis of the design described in Reference 1, the plant was partitioned into seven independent subsystems (ISSs), shown in Figure 1. A fault tree was developed for each subsystem to relate the occurrence of a top-level event (e.g., subsystem failure) to the individual components within the subsystem that could cause the event. Figure 2 is an example of a fault tree. Probability expressions were then developed for each subsystem type on the basis of fault trees and data availabilities that represent the probabilities of the top-level events as a function of the constituent component failure and repair characteristics.

System states and their associated capabilities were defined in terms of the operational

Table 1 Heber Plant Independent Subsystems (ISSs)		
ISS	Subsystem	Description
1	Brine/Hydrocarbon Heat Exchanger	Two trains with four stages per train
2	Turbine/Generator	One turbine and one generator
3	Hydrocarbon Condensers/ Accumulators	Three sets of two condensers per accumulator and one set of one condenser and one accumulator
4	Hydrocarbon Circulation Pump	Six pumps normally operating
5	Cooling Tower Fan Modules	Seven fan modules normally operating
6	Cooling Water Circulation Pumps	Two pumps normally operating, with one spare
7	Brine Reinjection Booster Pumps	Two pumps normally operating

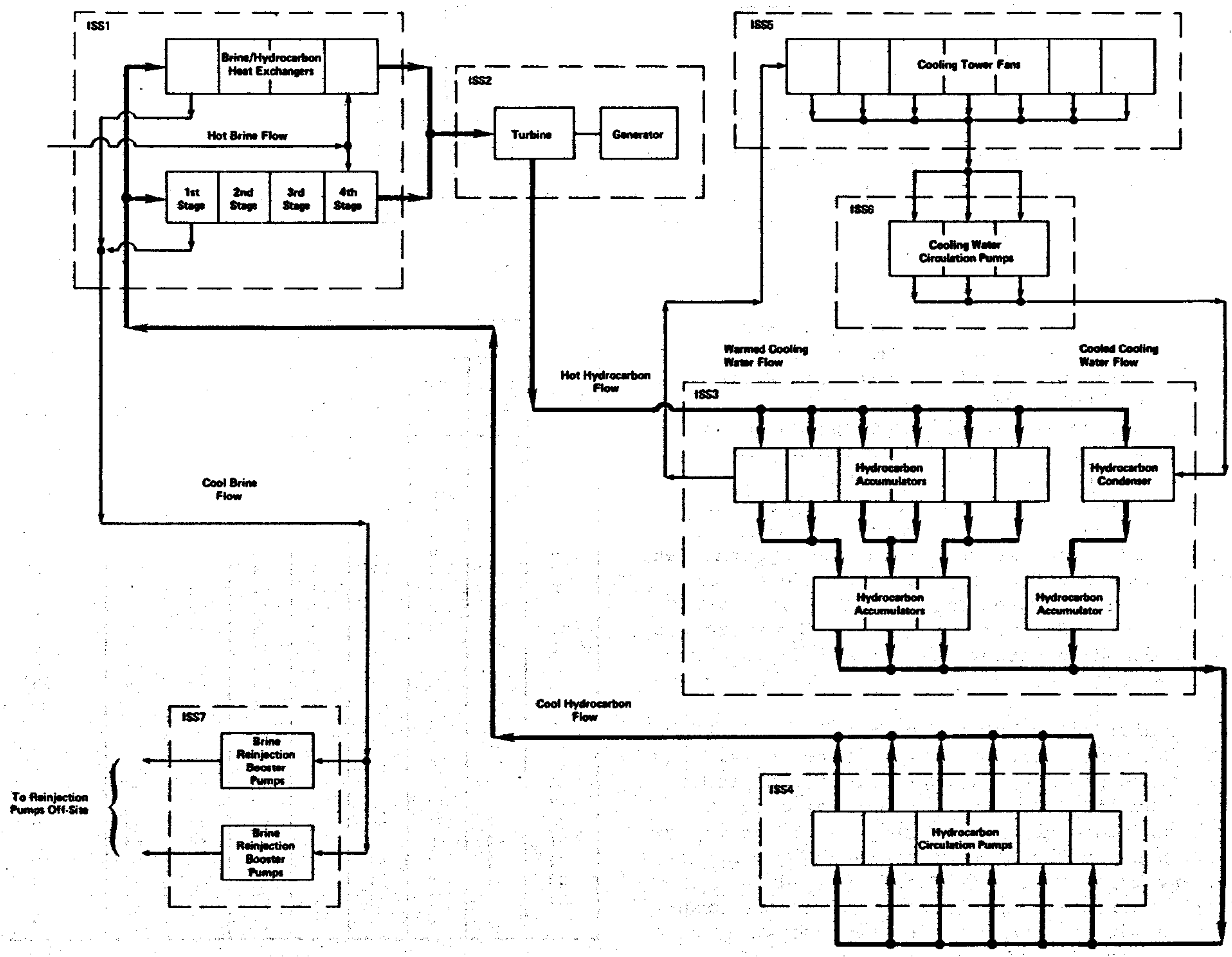

Figure 1 Heber Binary Plant Schematic

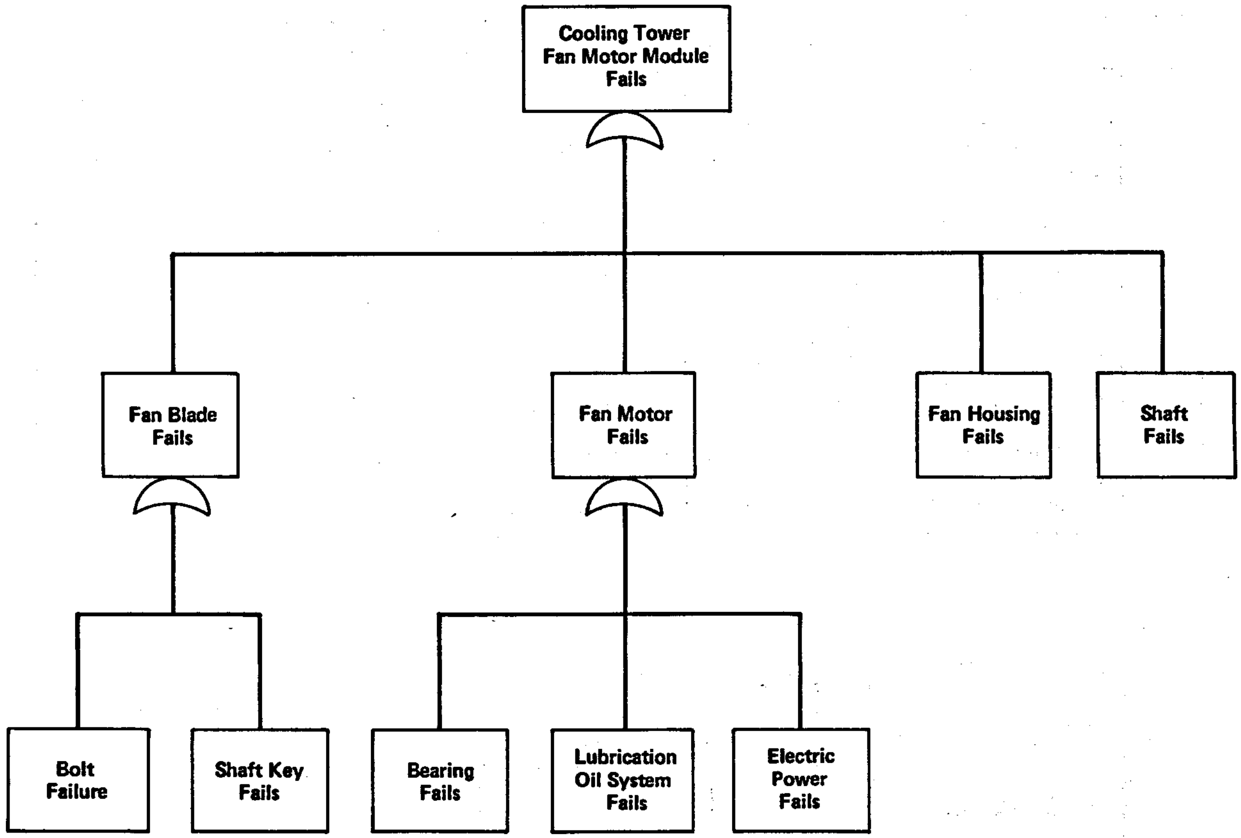

Figure 2 Example of Fault Tree

conditions of the seven identified ISSs. Twenty-five system states and their associated capabilities were defined, with the assistance of the Ben Holt Company (Ref. 2). These states and their capabilities (expressed as a percentage of maximum capacity) are shown in Table 2. The numbers in parentheses represent the quantity of component sets in each subsystem. The entries in the table represent the number of failed items for each subsystem that were used to define a given state (e.g., in State 1, no failures are permitted in any ISS except for ISS6, which has a standby spare and hence can have either zero or one failure but not two).

The individual subsystem expressions are then used in conjunction with the state definitions to define probability expressions that represent the likelihood of moving from each defined state to each other possible state, or remaining in the same state in a given short interval of time, $\Delta\tau$. This resulted in a 25-by-25 matrix of expressions, called the transition matrix, and used in the assessment model that will be described in the following section.

A component failure and repair data base was then developed. Table 3 summarizes those organizations which provided information for the study. A number of problems were encountered in developing this data base. First, there were virtually no data available on like components that could be used. There was a

Table 2 Heber System-State Definitions

State	ISS1 (2)	ISS2 (1)	ISS3 (4)	ISS4 (6)	ISS5 (7)	ISS6 (2+1)	ISS7 (2)	Percentage of Maximum Capacity
1	0	0	0	0	0	<2	0	100
2	0	0	0	0	1	<2	0	86
3	0	0	0	1	<2	<2	0	83
4	0	0	1	<2	<2	<2	0	75
5	0	0	<2	<2	2	<2	0	72
6	0	0	<2	2	<3	<2	0	67
7	0	0	<2	<3	3	<2	0	58
8	1	0	<2	<3	<4	<2	0	50
9	<2	0	2	<3	<4	<2	0	50
10	<2	0	<3	3	<4	<2	0	50
11	<2	0	<3	<4	<4	2	0	50
12	<2	0	<3	<4	<4	<3	1	50
13	<2	0	<3	<4	4	<3	<2	43
14	<2	0	<3	4	<5	<3	<2	33
15	<2	0	<3	<5	5	<3	<2	29
16	<2	0	3	<5	<6	<3	<2	25
17	<2	0	<4	5	<6	<3	<2	17
18	<2	0	<4	<6	6	<3	<2	15
19	2	<2	<5	<7	<8	<4	<3	0
20	<2	1	<5	<7	<8	<4	<3	0
21	<2	0	4	<7	<8	<4	<3	0
22	<2	0	<4	6	<8	<4	<3	0
23	<2	0	<4	<6	7	<4	<3	0
24	<2	0	<4	<6	<7	3	<3	0
25	<2	0	<4	<6	<7	<3	2	0

Table 3 Summary of Data Sources	
Petro-Chemical Industry Chevron Sun Oil Velsicol Great Lakes Chemical	Heavy Equipment Industry Elliott Magna Power
Power Industry EPRI NERC EEI CP&L PEPCO AP&L	Architect Engineer Industry Ben Holt Fluor

limited quantity of data on similar equipments (e.g., for different sizes of equipment or equipment operating in different environments) that could be extrapolated to the Heber design. The data that were available or could be estimated by knowledgeable sources were at a high level of indenture in the fault trees rather than at the lower component levels. Many of the sources contacted either did not collect this type of information or, in cases where they did, would not release it for proprietary reasons. As a result, the data base consisted of extrapolations of available hard data combined with estimates by consensus from the knowledgeable personnel in the organizations contacted.

A program designed for interactive time-share computer application was developed to determine the reliability and availability assessments and to perform sensitivity analyses. Baseline reliability and availability assessments were made by using the acquired data base, and component rankings were developed following sensitivity analyses. Finally, components with potential reliability growth were identified; a time-phased scenario of the growth was hypothesized; and the model was re-exercised for the improved components to produce an estimate of the potential availability growth with time.

Assessment Model Description The Heber plant, like other advanced power-generation plants, is a reasonably complex system capable of operating over a number of states, ranging from full capacity to no capacity. To adequately represent these conditions in assessing plant reliability and availability, a systems-effectiveness approach was employed. As noted earlier, this approach was initially developed and applied to a gasification combined-cycle plant. This assessment methodology is described in detail in References 3 and 4. The following definitions were employed in the assessment of the Heber plant by using this methodology:

- Reliability Measure. The time for the plant to reach an *a priori* defined level of effectiveness in the absence of corrective maintenance, given that the plant was initially in a completely "up" condition. (For this analysis a 50 percent level of effectiveness was used.) This time represents a measure of the inherent reliability of the plant design.
- Availability Measure. The steady-state effectiveness value when corrective maintenance is included.
- Effectiveness. The weighted contribution of each possible system state to the plant's output capacity. It can be expressed as an absolute (e.g., megawatts) or as a percentage of maximum capacity, and it represents an averaging over the possible system states or expected value for the plant. Further, since the likelihood of being in each particular state will vary with time, effectiveness will be a time-dependent quantity that will approach zero if repair is not permitted, and it will approach a finite steady-state value when repair is permitted.

The effectiveness function is determined by a Markov analysis and is defined for the interval $(t, t + \Delta t)$ by the following matrix products:

$$E(t, t + \Delta t) = A(t)T(t, t + \Delta t)C$$

where the matrices are defined as follows:

- $A(t)$ is a row matrix, called the availability matrix, whose elements $A_i(t)$ are the probabilities that the system is in each of its possible states at time t. If there are N_s possible states, then

  $$\sum_{i=1}^{N_s} A_i(t) = 1$$

  for all values of t. Initially, i.e., at $t = 0$, $A(0) = (1,0,\ldots 0)$ indicating that the system is in an "all up" condition, with zero probability of being in a state of degraded capability.
- $T(t, t + \Delta t)$ is a square matrix ($N_s \times N_s$), called the transition matrix, whose elements (T_{ij}) are the probabilities of the system's transitioning from state i to state j during the interval $(t, t + \Delta t)$. These probabilities are defined by the constituent

subsystem reliability and maintainability probability expressions and the state definitions. The time interval, Δt, is made sufficiently small so that the probability of multiple events occurring during the interval is negligibly small. Further, when corrective maintenance is not permitted (i.e., for the reliability assessment), all elements of the transition matrix containing repair events are set to zero.

- C is a column matrix having N_S elements, called the capability matrix. Each element (C_i) represents the capacity of the plant when it is in state i. For the Heber analyses, the capacity of each state was expressed as a percentage of the maximum capacity.

Analysis Results As noted earlier, the data estimates obtained were only at a high level of indenture (i.e., subsystem or major component) rather than at the level of the fault tree. Table 4 summarizes the baseline data for the components and subsystems. The estimated mean times between failures and mean times to restore are shown for the level of indenture at which the data were obtained. For those cases in which these data were at a major component level, the corresponding subsystem values were also determined and presented.

Table 4 Heber Data Summary

ISS	Subsystem or Component	Components MTBF (Hours)	Components MTTR (Hours)	Subsystem MTBF (Hours)	Subsystem MTTR (Hours)
1	Brine/Hydrocarbon Heat Exchangers			1,980	168
2	Turbine/Generator			16,545	307
	Turbine	25,820	370	--	--
	Generator	46,445	193	--	--
3	Hydrocarbon Condensers/ Accumulators			19,147	316
	Condenser	43,560	366	--	--
	Accumulator	158,400	168	--	--
4	Hydrocarbon Circulation Pumps			6,592	168
	Pump	7,920	168	--	--
	Motor	39,300	168	--	--
5	Cooling Tower Fan Modules			7,011	710
	Fan	15,840	1,512	--	--
	Motor	12,575	72	--	--
6	Circulating Water Pumps			210,900	57
	Pump	1,265,398	100	--	--
	Motor	253,080	48	--	--
7	Brine Reinjection Booster Pumps			9,900	48

Baseline evaluations of the Heber reliability and availability were obtained by using the data in Table 4 and by exercising the assessment model. The resultant curves of effectiveness versus time for the two assessments are shown in Figure 3. It can be seen that the time for the plant to decrease from 100 percent to 50 percent expected capacity in the absence of corrective maintenance was 37.5 days. Comparable values obtained from assessments of GCC and CFP designs were about 9 days and 8 days, respectively. Similarly, the availability assessment can be seen to approach a steady-state value of about 81 percent. The corresponding GCC and CFP availability measure values were 79 percent and 82 percent, respectively.

Table 5 presents the steady-state availabilities for each of the defined system states. The table shows that the most likely state is the "all up" state (State 1), with an availability of 34.2 percent. Further, it can be seen that the probability of at least 75 percent capacity is 0.71 and that the probability of a full outage is approximately 0.02. Finally, it was determined from the results of the baseline assessment that the probability of 100 percent capacity for five days was 0.885 and the probability of at least 75 percent capacity for sixty days was 0.725.

Sensitivity analyses were performed to determine the effect that changes in the baseline data would have on the resultant steady-state effectiveness value. Component rankings were developed in accordance with the following criteria:

- Power Lost -- the increase in steady-state effectiveness when a component is made perfect.
- Availability -- the change in steady-state effectiveness per change in component availability.
- Failure Rate -- the change in steady-state effectiveness per change in component failure rate.
- Mean Time to Restore -- the change in steady-state effectiveness per change in component mean time to restore.

The expressions used to determine the ranking scores are presented in the Appendix of this paper. The resultant rankings are shown in Table 6. The table indicates that the heat exchanger represents the most sensitive component, whereas the circulating water pump and motor have a comparatively negligible impact.

Reliability Growth As a part of the baseline data-collection effort, potential areas of reliability improvement were investigated, and, where possible, source estimates of

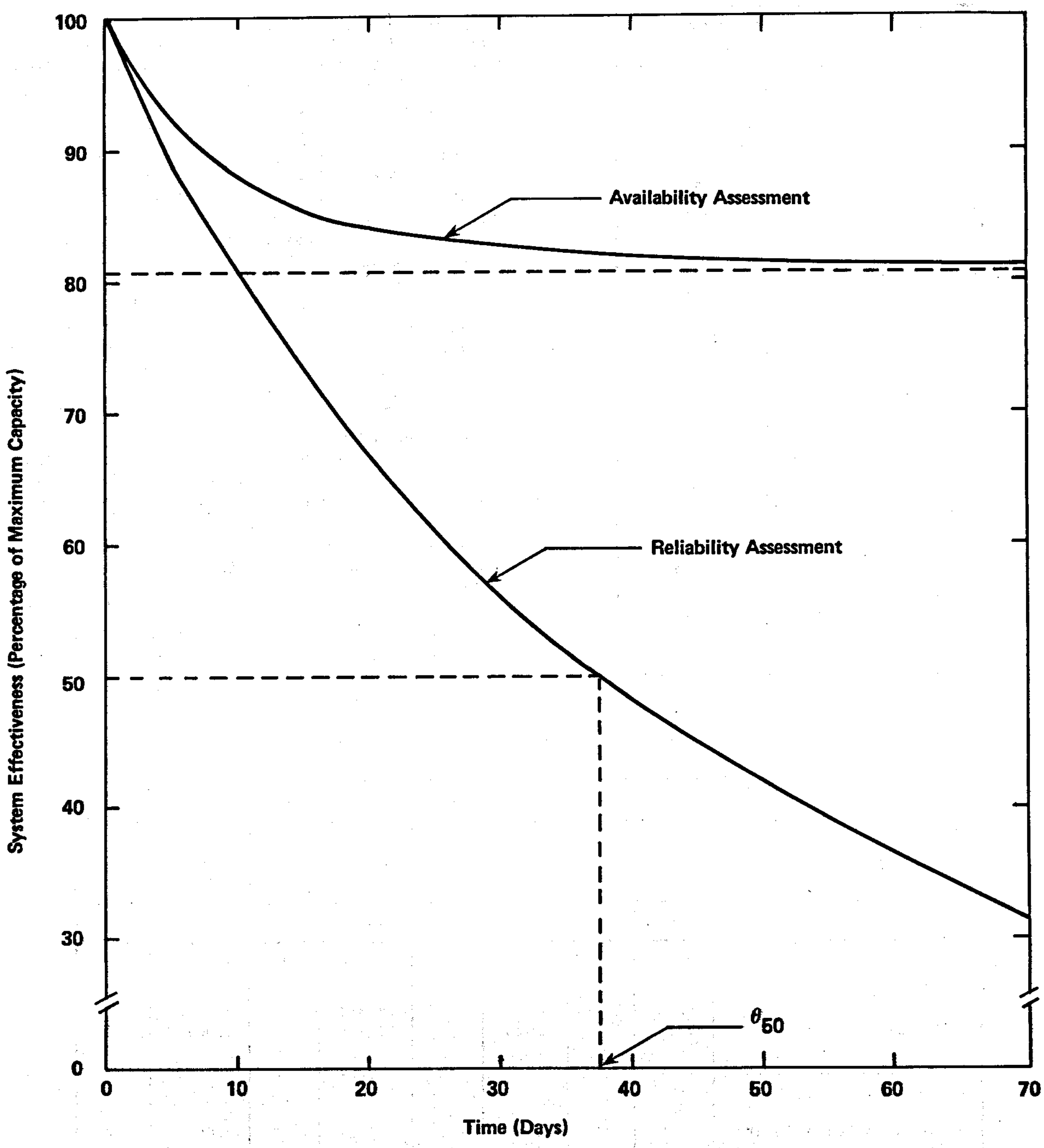

Figure 3 Assessment Results of Heber Baseline Reliability and Availability

expected growth were questioned. Table 7 presents a summary of the identified potential improvements, their estimated timing relative to the initial plant operation date, and their estimates of improved MTBFs. The impact of these improvements was evaluated by using the assessment model; this impact is illustrated in Figure 4. It can be seen that implementation of the identified improvements, coupled with reliability growth estimates by the sources, would increase the steady-state effectiveness by about nine percent over a ten-year period. In addition, further growth could be achieved by introducing bypass capabilities in the heat exchanger and the condenser/accumulator subsystems. This, for example, would permit operation of the plant in additional higher-capacity states when a failure occurs in a heat exchanger rather than losing the entire subsystem and dropping to 50 percent capacity.

Table 5 Summary of Steady-State Availabilities		
State	Percentage of Capacity	Percentage of Availability
1	100	34.2
2	86	23.7
3	83	8.6
4	75	4.5
5	72	8.7
6	67	0.6
7	58	1.4
8	50	14.4
9	50	0.1
10	50	<0.1
11	50	<0.1
12	50	1.0
13	43	0.2
14	33	<0.1
15	29	<0.1
16	25	<0.1
17	17	<0.1
18	15	<0.1
19	0	0.6
20	0	1.8
21	0	<0.1
22	0	<0.1
23	0	<0.1
24	0	<0.1
25	0	<0.1

<u>Conclusions and Recommendations</u> Evaluation of the Heber design, using the baseline data, produced reliability and availability estimates that were equal to or better than previously evaluated GCC and CFP designs. The heat exchanger has the greatest impact on the steady-state availability. An additional nine percent growth in steady-state availability could be realized through a combination of expected component reliability growth and the improvements resulting from the implementation of several design changes.

The assessment model can and should be used to update the assessments as the Heber design evolves and also to evaluate candidate design alternatives as they are proposed. The state-capacity definitions used were based on linearity assumptions within the plant. Heat-balance analyses should be conducted to obtain more accurate state capacity values, and the assessments and component rankings should be updated as necessary. The failure and repair data base should be expanded to lower levels of indenture, and the assessments and rankings should be updated accordingly. This will probably necessitate performing detailed component failure modes and effects analyses, since the data-collection effort indicated that the data were not available at these levels. Finally,

Table 6 Heber Component Rankings

Component	Ranking by Criterion							
	Power Lost		Component Availability		Component Failure Rate		Component Mean Time to Restore	
	Score	Rank	Score	Rank	Score	Rank	Score	Rank
Hydrocarbon/Brine Heat Exchanger	5.92	1	76.7	3	10,948	5	0.03291	1
Turbine	1.16	3	81.7	1	29,381	2	0.00308	6
Generator	0.34	7	80.9	2	15,485	4	0.00173	7
Hydrocarbon Circulating Pump	0.97	4	48.4	9	7,797	8	0.00586	3
Hydrocarbon Circulating Motor	0.20	9	47.6	10	7,929	7	0.00120	8
Cooling Tower Fan	5.86	2	69.7	4	87,824	1	0.00367	5
Cooling Tower Motor	0.36	6	64.1	6	4,563	9	0.00504	4
Circulating Water Pump	0	12	1.0	12	100	11	0	12
Circulating Water Motor	0	11	1.0	11	48	12	0	11
Brine Reinjection Booster Pump	0.31	8	64.5	5	3,066	10	0.00645	2
Hydrocarbon Condenser	0.39	5	51.8	7	18,645	3	0.00117	9
Hydrocarbon Accumulator	0.05	10	51.5	8	8,633	6	0.00032	10

Table 7 Potential Reliability Improvement Candidates				
Component	ISS Baseline MTBF (Hours)	Estimated Improved MTBF (Hours)	Improvement	Assumed Timing
Hydrocarbon/Brine Heat Exchanger	1,980	7,920	Change tubing materials to titanium	5th year of operation
Hydrocarbon Condensers/ Accumulators	19,147	34,165	Change tubing materials to a copper-based alloy	5th to 7th year
Hydrocarbon Circulation Pumps	6,592	11,290	Change to oil mist system	3rd to 7th year
Cooling Tower Fans	7,011	14,020	Change fan blading materials	3rd to 7th year
Circulating Water Pump Motors	210,900	361,545	Manufacturer's estimated reliability growth	5th to 10th year
Brine Reinjection Booster Pumps	9,900	19,800	Manufacturer's estimated reliability growth	3rd to 7th year

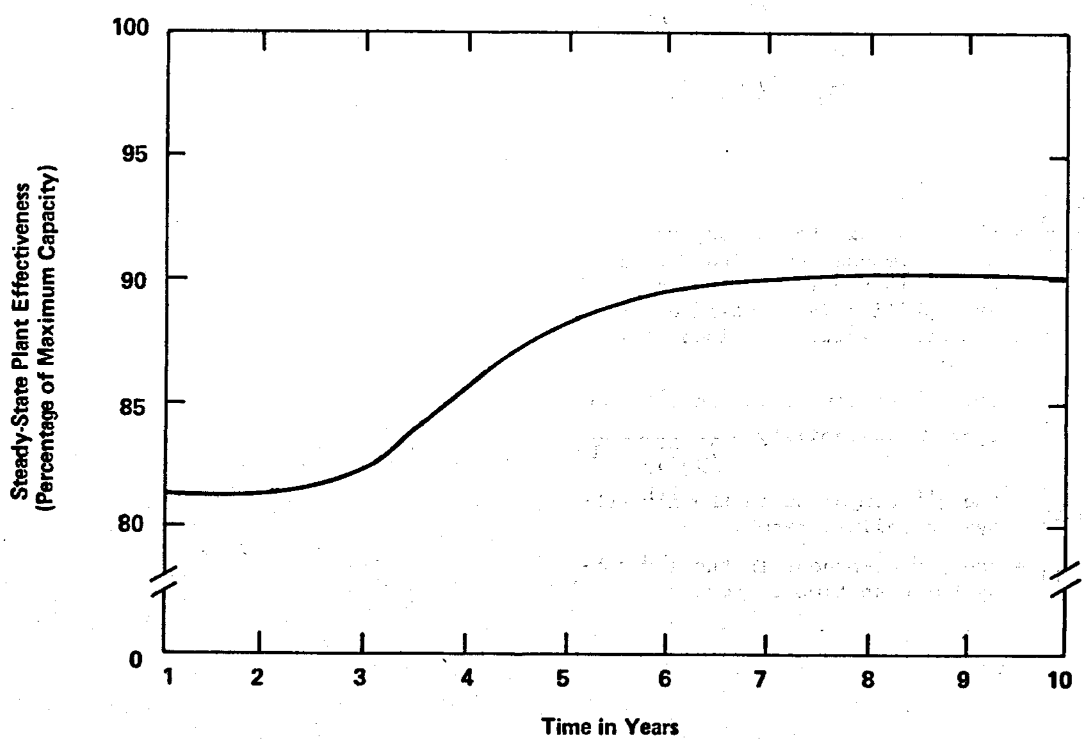

Figure 4 The Effects of Reliability Growth on Steady-State Effectiveness for Heber

consideration should be given to applying this analysis methodology to other geothermal plant designs and to establishing an overall geothermal component failure and repair data base that can support these efforts.

Appendix: Component-Ranking Expressions The following presents the mathematical formulations employed in obtaining the scores for the four component-ranking criteria used in the analysis.

- Power Lost = $\lim_{A_{ij} \to 1} \left(E_{ss}\right) - E_{ss}$

- Availability = $\dfrac{\delta E_{ss}}{\delta A_{ij}} = \dfrac{\delta E_{ss}}{\delta A_i} \dfrac{\delta A_i}{\delta A_{ij}}$

- Failure Rate = $\dfrac{\delta E_{ss}}{\delta \lambda_{ij}} = \dfrac{\delta E_{ss}}{\delta A_i} \dfrac{\delta A_i}{\delta A_{ij}} \dfrac{\delta A_{ij}}{\delta \lambda_{ij}}$

$$= \frac{\delta E_{ss}}{\delta A_i} A_i \; A_{ij} \; \tau_{ij}$$

- Mean Time to Restore = $\dfrac{\delta E_{ss}}{\delta A_i} \dfrac{\delta A_i}{\delta A_{ij}} \dfrac{\delta A_{ij}}{\delta \tau_{ij}}$

$$= \frac{\delta E_{ss}}{\delta A_i} A_i \; A_{ij} \; \lambda_{ij}$$

where

$\dfrac{\delta E_{ss}}{\delta A_i}$ = the change in the steady-state effectiveness resulting from a change in the i^{th} subsystem availability (A_i) obtained from the sensitivity exercises of the model

A_{ij} = the j^{th} component in the i^{th} subsystem availability = $\dfrac{1}{\lambda_{ij}\tau_{ij} + 1}$

λ_{ij} = the j^{th} component in the i^{th} subsystem failure rate

τ_{ij} = the j^{th} component in the i^{th} subsystem mean time to restore

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FIELD TESTS OF THE BIPHASE GEOTHERMAL ROTARY-SEPARATOR TURBINE

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ABSTRACT

An experimental Biphase Rotary-Separator Turbine (RST) was designed for moderate wellhead brine conditions. The 30-inch RST was fabricated, mounted in a trailer together with its controls and instrumentation, and tested under laboratory and field conditions. Electric-power production, clean-steam production, and brine repressurization for injection were measured at three different locations with various brine temperatures and compositions. The measured power output at design conditions was equivalent to the production of 25 percent more electricity per unit of brine than would be produced by an optimized single-stage flash power system operation at the same resource conditions. A full-size nozzle test rig was also field-tested to evaluate the critical performance parameter of nozzle efficiency operating on wellhead, high-salinity flows. Nozzle tests simplified the method of resource evaluation.

Significant flexibility in handling the range of resource temperatures leads to a 54-inch wellhead-size RST suitable for use on a variety of geothermal resources or on a resource that changes with time

INTRODUCTION

The rotary-separator turbine (RST) is a geothermal power-conversion system that extracts work from the thermal energy of geothermal brine. The system is capable of receiving two-phase flow directly from a geothermal well, separating the liquid and vapor phases after expanding them together in a nozzle, and supplying three forms of output energy: (1) electricity produced by a liquid turbine/generator driven by the accelerated liquid, (2) steam at pressure capable of producing electricity if expanded further in a steam turbine/generator, and (3) liquid (brine) at pressure suitable for reinjection back into the geothermal reservoir. The RST increases the efficiency of power generation from a geothermal resource by extracting power from the kinetic energy imparted to the liquid phase.

The Electric Power Research Institute (EPRI) awarded Biphase Energy Systems a contract to apply the Biphase RST concept to geothermal-power systems. The EPRI/Biphase project includes evaluation and development of the geothermal application through turbine design, fabrication, and field testing. This paper describes the testing of the 30-inch experimental unit, compares the RST system to single-stage direct flash based on performance measured in the tests, and discusses field-test simplification using a test rig for a full-size nozzle.

FIELD-TEST PROGRAM

The experimental RST was fabricated, mounted in a trailer together with its controls and instrumentation, and tested under laboratory and field conditions. Test objectives were satisfactorily met; these included:

1. Demonstrate mechanical turbine output power, clean steam separation and delivery, and delivery of pressurized return brine.

2. Demonstrate equipment reliability in the field operating environment.

3. Quantify performance trends; provide reliable design mathematical model; demonstrate wide flexibility in fluid conditions.

4. Compare Biphase wellhead system performance with alternate approaches to geothermal power.

The RST, Figure 1, has three rotating elements: the primary separator, the U-tube liquid turbine, and the liquid-transfer rotor. Geothermal brine enters the system through nozzles, and clean steam and repressurized brine leave the system; the brine exits via a stationary diffuser. A complete wellhead system would include an RST and a steam turbine, with the RST producing steam of the quality required by the steam turbine. The shaft power produced by the liquid U-tube turbine in the RST is the margin of performance superiority over a single-stage flash-steam system using only a steam turbine.

Initial test operation of the RST took place at the Biphase laboratories. Components were tested and developed separately. Then the test trailer was transported to East Mesa, California for a three-week period of operation. The trailer was

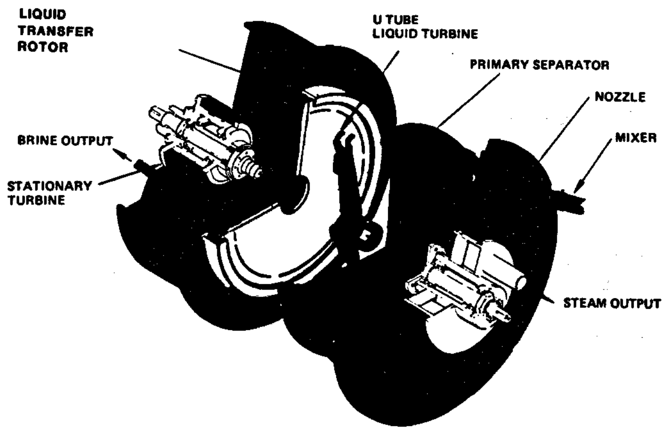

Figure 1. Rotary-separator turbine.

returned to the laboratory for performance tune-up involving the rotary-separator windage, then sent to Raft River, Idaho, for tests, and finally to Roosevelt Hot Springs, Utah.

Design conditions for the prototype were selected as shown in Table 1. RST inlet pressures of 80 psia and temperatures of 312°F are generally compatible with resource downhole pressures of 150 psia and temperatures of 350°F. Analysis and experiment have led to the expectation of satisfactory performance over a wide range of inlet condition; the three field test sites supplied brine temperatures ranging from 265°F at Raft River to 352°F at Roosevelt Hot Springs. The RST was operated near design conditions at Roosevelt and at East Mesa, and with a wide variety of off-design conditions indicated in Table 1. In addition to temperature variations, the three field sites supplied brine of various composition of dissolved solids and gases.

Item	Design Point	Laboratory	East Mesa	Raft River	Roosevelt
Fluid Inlet Temperature, (°F)	312		285-329	265-279	203-352
Nozzle Inlet Pressure (psia)	80	23-80	35-141	62-112	27-84
Exhaust Pressure (psia)	14.7	14.7	14.7	13.8 & 7.3	13.1
Total Flowrate (lb/sec)	4.7		1.6-9.3	1.9-5.6	0.5-4.1
Nozzle Inlet Steam Quality	0.05		0-0.05	0	0.05-0.10
Power (kW)	27.7		1.5-29.6	9.0-9.3	1.2-28
Steam Output Quality		0.9990-0.9995	0.9996	0.98-0.999	0.985-0.999
Brine Output Pressure (psia)	56		28-105	31-52	16.72
Hours Operation		114	112	30	60

Table 1. Design and range of operating conditions.

FIELD OPERATIONS

Prototype test operations at East Mesa utilized Well No. 6-2. Early difficulty with carbonate-scale formation in the RST nozzles was cured by addition of 2 to 10-ppm quantities of an organic phosphate. The test program was completed with no further scale problems on any of the test equipment. Results showed good performance of the nozzles, U-tube liquid turbine and diffuser, and reduced performance of the rotary separator due to high windage. High windage was traced to liquid droplets in the housing. When the equipment was returned to the Biphase laboratory, the nozzles, U-tube turbine, and separator geometry were tuned-up to eliminate the stray liquid. Windage was reduced by a factor of four. For the remainder of the program the component parts were unchanged, and performed as described by the mathematical model.

Tests at the DOE Geothermal Test Facility at Raft River, Idaho, were made with brine conditions significantly below design. An initial hook-up placed the test trailer approximately one mile from the wellhead. Wellhead brine temperature of 285°F decreased to 255°F at the trailer input, a temperature too low for meaningful tests. The trailer was then moved to the wellhead where tests were conducted. A series of tests was made employing a steam condenser to reduce back pressure to about one-half atmosphere. Brine enthalpy extraction under these conditions was more than doubled. In these subatmospheric tests the RST produced about 80 percent of the power that a single-stage steam turbine would have produced from the same brine flow. This means that an RST unit could be used without a steam turbine and still get most of the power that a direct-flash system could get from a low temperature hydrothermal resource.

The RST test trailer was moved directly from Raft River to Roosevelt Hot Springs, Utah. Brine conditions were in the range of RST design, so component performance was measured in the design ranges. Power output was measured at the design value of 20 kWe.

RESULTS

Significant results of the field tests included demonstration of hardware durability with various brine compounds, demonstration of significant flexibility in handling off-design conditions, and correspondence of test to a performance model. The model is now used with confidence for scale-up and optimization. Other results include measurement of power output, steam quality, diffuser performance, and resource-utilization advantage.

<u>Power Output</u> of the RST, measured under a variety of inlet pressures and inlet-steam qualities, is presented in Figure 2, with experimental points related to performance-model predictions. Design-point machine efficiency of 36 percent was measured at Roosevelt Hot Springs.

<u>Steam Quality</u> is important to a wellhead system where the steam from the RST is delivered to a steam turbine. Output steam quality was measured with a throttling calorimeter and also by a chloride analysis. The two methods agreed within one percent. The steam separation mechanism depends upon high rotor speed, so that the brine and steam are separated in a high-gravity field. At design rotor speeds, steam quality of 0.9996 was

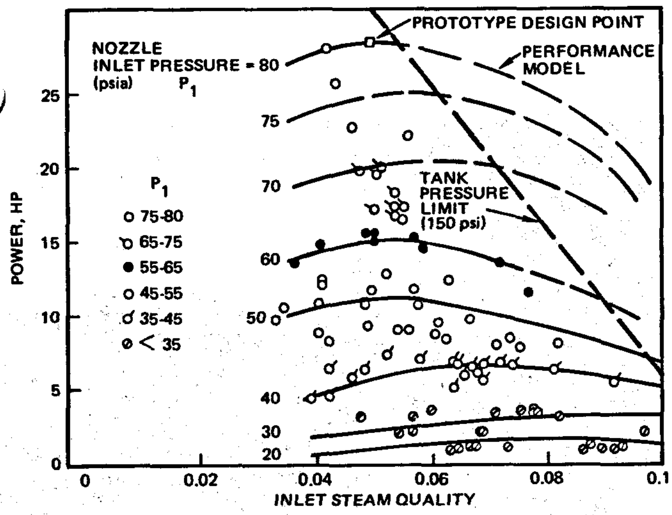

Figure 2. Measured output power as a function of inlet steam quality and nozzle inlet pressure.

measured. Figure 3 illustrates quality measurements at off-design conditions, and includes some measurements below 0.99 with rotor speeds well below design.

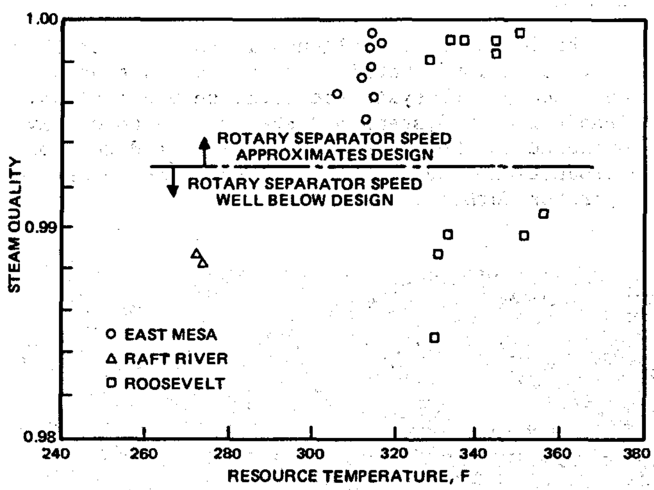

Figure 3. Experimentally-determined steam quality leaving RST, based on TDS analysis.

Stationary Diffuser performance is important for adjusting brine-delivery pressure as needed for reinjection. Brine repressurization is accomplished by retaining a portion of the liquid kinetic energy on the transfer rotor, and then converting this kinetic energy to pressure in a stationary diffuser. The energy partition is accomplished by adjustment of the turbine-to-separator speed ratio; as shown in Figure 4, pressures equal to or exceeding brine-entry pressures are obtained by operating the liquid turbine in the range 0.54 to 0.6 of separator speed.

Resource Utilization Advantage has been calculated using experimentally RST performance and inlet/outlet conditions, together with calculated steam turbine, condenser, and accessory power conditions.

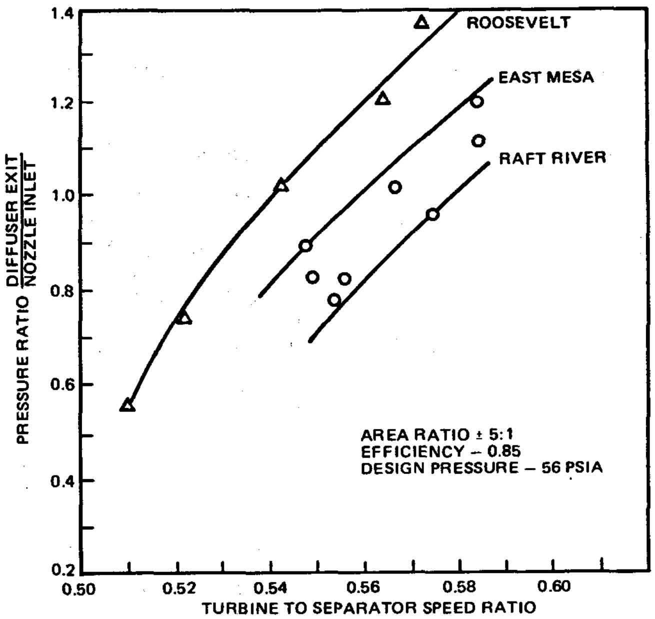

Figure 4. Experimental verification of stationary liquid-diffuser performance

The RST/steam-turbine power output is compared by the utilization ratio to an optimized single-stage flash system. The ratio, determined by the RST performance model shown in Figure 5, was confirmed by the experimental data.

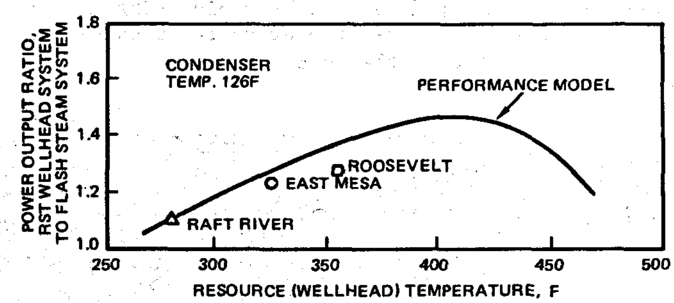

Figure 5. Comparison of experimental determination with theory, resource utilization advantage for Biphase single-stage RST/steam-turbine system to optimized single-stage flash system.

NOZZLE-CALIBRATION TESTS

The single most critical component-performance efficiency is that of the nozzle. For instance, the decline in power-output ratio (RST system compared to single-stage flash system) at lower temperature shown in Figure 5 is due primarily to the lower nozzle efficiencies at the lower temperatures. To verify nozzle-efficiency predictions, a calibration-test rig was assembled for field testing of nozzles that would be full-size for a wellhead unit. This calibration-test rig was operated at a Union Oil wellhead in the Salton Sea geothermal area. The test was designed to confirm predictions by the RST calculation model and to obtain off-design performance data. The results of the nozzle field tests are shown in Figure 6.

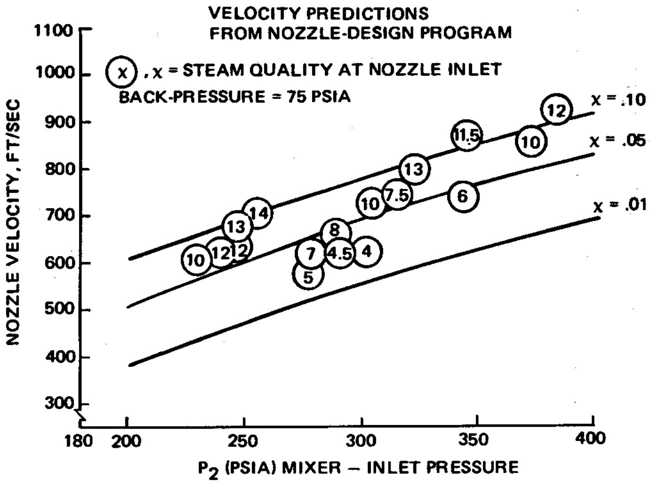

Figure 6. Experimental nozzle exit velocity.

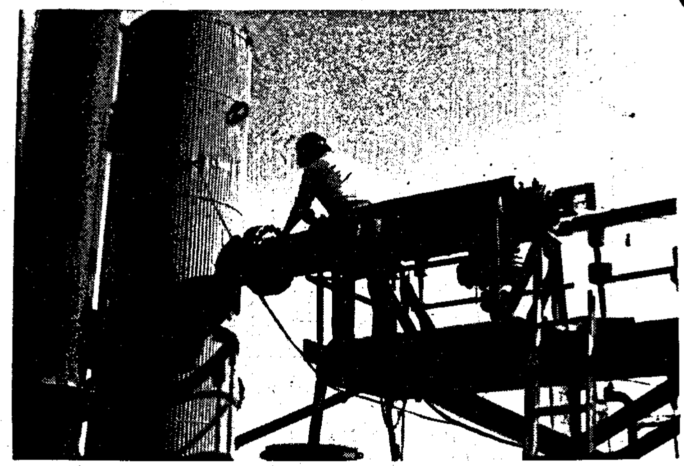

Figure 7. Nozzle test rig.

The test nozzle was full-sized relative to a wellhead RST. Nozzle velocity is determined from force measurements, and these data may be compared to theoretical results obtained from the mathematical model, Figure 6. The close agreement between observed and predicted performance at near-design conditions is very encouraging, because the four-nozzle design of the RST will make most conceivable operating conditions achievable using one or more nozzles flowing at or near design conditions. Figure 7 illustrates the nozzle rig.

SUMMARY

Field tests accomplished in the test trailer, Figure 8, and the nozzle test rig demonstrated consistency with system-performance predictions. Biphase Energy Systems and EPRI have accordingly continued in the design, production, and test of a production-type 54-inch wellhead-size Rotary Separator Turbine.

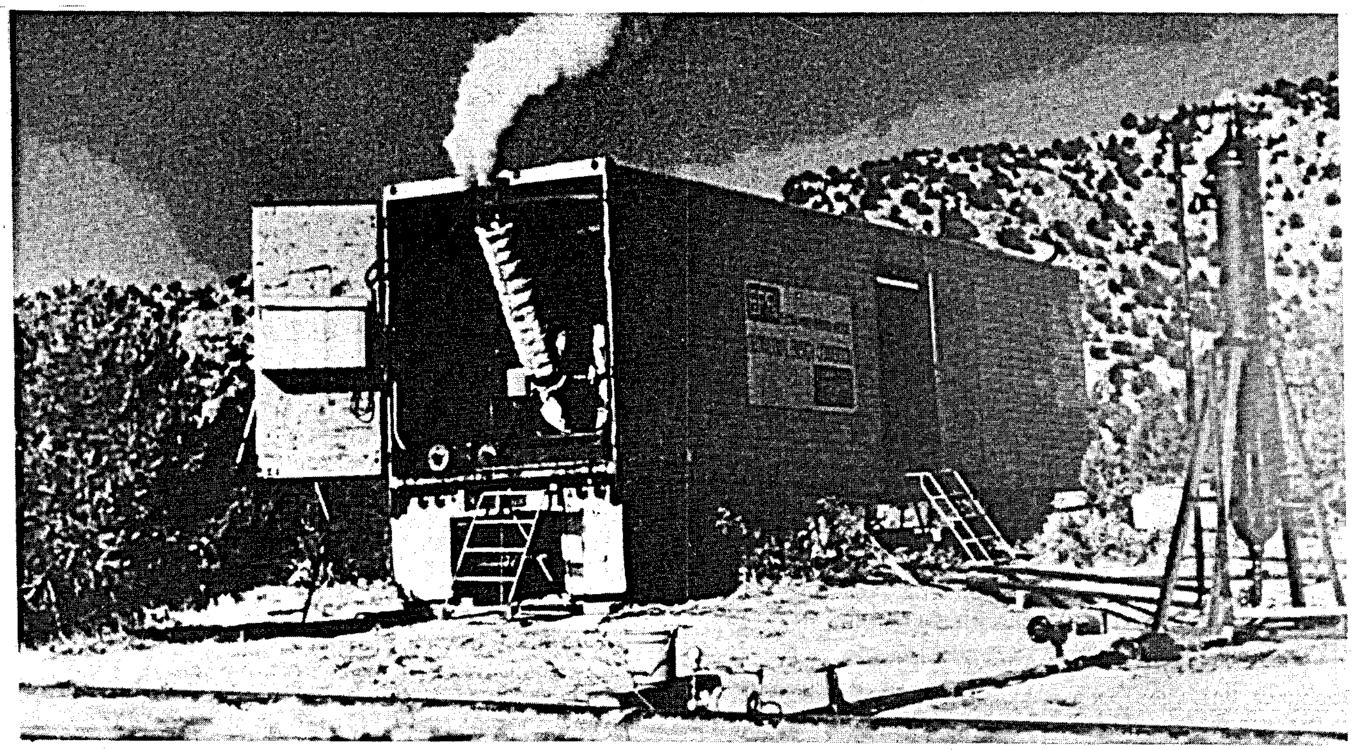

Figure 8. Geothermal test trailer.

UPSTREAM REBOILING FOR NONCONDENSABLE GAS REMOVAL

CONTRACT NO. RP1197-2

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I. Project Objectives and Results The objective of this project was to evaluate a heat exchanger process for removal of H_2S and other noncondensable gases from geothermal steam. The process was conceived by Coury and Associates, Inc. and has been developed and tested by both Coury and EPRI through this project and through other efforts by Coury. The heat exchanger process is shown schematically in Figure 1. Both the shellside and tubeside of the heat exchanger are at saturated conditions, with the tubeside at a pressure and temperature slightly lower than the shellside. This temperature difference causes heat transfer to occur so that saturated steam condenses in the shellside and saturated condensate evaporates in the tubeside. The incoming geothermal steam, directly from a well in the case of a vapor-dominated resource or from a vapor-liquid separator at hydrothermal locations, is almost completely condensed. The resulting condensate will dissolve some gases, but about 98 percent of the total noncondensable gases in the steam will remain in the vent gas stream. Over a typical range of geothermal steam compositions and process operating conditions, 90 to 99 percent of the H_2S will remain in the vent stream. The shellside condensate is transferred to the tubeside and is reevaporated as it circulates through the tubes. The total resulting tubeside vapor leaves the heat exchanger as clean steam.

In addition to achieving over 90 percent removal of H_2S and other noncondensable gases this process can operate at wellhead pressures and temperature and does not require any chemical additives to the main steam, thus making it suitable for operation upstream of a geothermal power plant turbine. Upstream removal of H_2S and other noncondensable gases has several advantages over processes which remove H_2S downstream of the turbine. These include: (1) the steam within the turbine is cleaner and less corrosive which should result in increased turbine reliability; (2) H_2S cannot get into the turbine condensate where it could require difficult liquid phase treatment to meet plant H_2S emissions requirements; (3) the removal of noncondensables ahead of the turbine reduces the steam requirements for the steam jet air ejectors which control the vacuum in the main condenser; (4) steam can be vented through the upstream unit, as a stacking operation when the power plant is not operating, thus avoiding the necessity to close down wells during such periods; and (5) the removal of gases from the condenser increases the power production in the turbine.

The project work included the testing of a small-scale, 150-ft^2 heat exchanger, similar to that shown in Figure 1. These tests were conducted with the cooperation of Pacific Gas and Electric Company at Unit 7 of The Geysers Power Plant, a dry steam geothermal resource north of San Francisco, California. The objectives of the test program were to: (1) demonstrate the capability of the process to remove at least 90 percent of the H_2S present in the incoming geothermal well steam; and (2) demonstrate the heat transfer performance of the falling-film vertical tube evaporator in a geothermal environment.

The test unit accumulated approximately 1000 hours of operating time with the following results:

- The measured H_2S removal rates were consistently better than 90 percent, with an average removal rate of 94 percent.
- At least 98 percent removal of the total noncondensable gases was indicated during the tests.
- Measured heat transfer rates were high enough to indicate acceptable economics for application of the process on a commercial scale. The average measured heat transfer coefficient was 576 Btu/(h·ft^2·°F) with indications that all measured values were conservative.
- The test unit demonstrated very simple and predictable operating characteristics during both steady state and transient conditions.

The project work also included studies for evaluating the cost and performance of various configurations and applications of the heat exchanger process. The results of these studies show the following:

- Alternative heat exchanger designs may improve heat transfer performance and reduce capital costs.
- The commercial-scale application of this

process would contribute about 4.4 mills/kWh to the electrical busbar cost of a typical 55-MW geothermal power plant.

- The effects of the steam pressure drop across the heat exchanger and steam consumption in the vent stream may be more than compensated for by beneficial effects on the total power plant system performance and on total net electric power production.

The final report for the project, Reference 1, presents a comprehensive discussion of the project work and results. In addition to the field test and studies mentioned above, the final report includes a complete preliminary design of a larger scale demonstration plant.

II. H_2S Removal

A. Predicted Removal Rates The removal of gases from geothermal steam is determined by how much of each gas dissolves in the liquid phase as the entering steam condenses. The amount of gas absorbed at equilibrium is controlled by three factors: (1) the partial pressure of the gas in the vapor phase; (2) the mass ratio of vapor to liquid in contact with each other; and (3) the pH of the liquid solution. The partial pressure of the gas depends on the amount of the gas present and the total pressure of the system. The mass ratio of vapor to liquid depends on the amount that is condensed; this ratio is a function of the vent rate, because more steam is condensed as less steam is vented. The pH of the liquid solution depends on the dissociation of the gases after they dissolve into the liquid phase. The amount of dissociation is determined by the appropriate equilibrium constants, which are a function of temperature, and by the concentration of the various gases in the steam. Thus, the major variables that affect gas removal are temperature, pressure, gas composition, and the percent of inlet steam vented.

If equilibrium is not achieved in the process, then removal is also dependent on the kinetic rates at which the various mass transfer steps occur. The question of equilibrium, or kinetics, has been evaluated resulting in the conclusion that the actual effect of kinetics will be insignificant with respect to the performance of the heat exchanger. This is discussed in more detail in the final report for this project (Reference 1).

A mathematical model was developed by Coury to predict the removal of H_2S and other gases from geothermal steam using the heat exchanger process. Figures 2 and 3 show the results of calculations using this model indicating better than 90 percent removal of H_2S for the wide ranges in H_2S, CO_2, and NH_3 concentrations that are expected to include most geothermal steams. Figure 2 represents a 98-percent condensing rate (2 percent vent rate) and Figure 3 shows a 90-percent condensing rate (10 percent vent rate). The inlet concentrations of H_2S and CO_2 covered in these figures range from 100 to 1000 ppm for H_2S and 3000 to 8000 ppm for CO_2. The inlet NH_3 concentration ranges from zero to 100 percent of the inlet H_2S concentrations. The pH values shown in the figures is dependent on the relative concentrations of the acid gases H_2S and CO_2 and the basic gas NH_3. As expected, the calculated H_2S removal increased with decreasing NH_3 concentrations, increasing CO_2 concentrations, and increasing vent rate. For conditions typical at The Geysers, as shown in Table 1, the model predicted better than 95 percent H_2S removal.

B. Test Unit Results Figures 4 and 5 show plots of H_2S removal versus vent rate and ΔT as measured with the test unit at The Geysers. The measurements ranged from 98.1 percent to 87.3 percent (the one point lower than 90 percent), with an average of 94.0 percent and a standard deviation of 2.1 percent. Although no conclusive correlation is shown between the H_2S removal rate and ΔT (no direct correlation is expected based on theory), these figures do indicate that the H_2S removal rate is dependent on the vent rate, increasing as the vent rate is increased, as predicted by theory. As seen in Figure 4, however, the linear curve fit of the data gives values slightly less than theoretical values based on average conditions at The Geysers, with this difference in percent removal values ranging from about 1 at a vent rate of 1 percent to about 3 at a vent rate of 10 percent.

Most of the data represented in Figures 4 and 5 are from baseline tests with vent rates between 2 percent and 8 percent of the inlet steam flow rate and ΔT's across the heat exchanger of between 5°F and 9°F. During the baseline tests the inlet steam composition was not modified and was similar to that shown in Table 1. A few of the data points in Figures 4 and 5 represent special tests such as high vent rate tests and gas injection tests. As expected, the high vent rate tests typically showed high levels of H_2S removal. Table 2 shows the results of detailed analyses of H_2S and other noncondensable gases in the various flow streams for four gas injection test cases during which the inlet steam composition was modified by injecting H_2S and NH_3, and one baseline test case during this same general time period. With each of the five cases in Table 2, the measured H_2S removal rates are compared with the predicted removal rates for the measured inlet H_2S and NH_3, and CO_2 concentrations and the measured vent rates for each case. The measured percent H_2S removal values ranged from 2 to 5 less than the predicted percent removal values, as the ratio of

NH_3 to H_2S concentration in the inlet steam ranged from 0.2 to 2.0.

As can be seen from Table 2, the predicted removal rate for H_2S remained fairly constant during the injection tests, ranging from 95 percent to 98 percent, even though the NH_3 to H_2S ratio increased. This is because the absolute amount of H_2S decreased as this ratio increased, and the two effects almost balanced each other. The measured H_2S removal rates also remained essentially constant as would be expected, ranging from 92 percent to 95 percent. Although these values are all somewhat lower than the predicted values, they are still within the limits of the probable error band based on the accuracy of the analytical methods. The predictive model thus appears to be adequate, although the number of tests were limited. Most importantly, these tests demonstrated the high capability for H_2S removal over a wide range of steam composition.

An error analysis of the H_2S removal data indicates that the expected variations in measured values of percent H_2S removal range from 0.5 to 2 due to normal fluctuations of H_2S and NH_3 concentrations at The Geysers, and from 1 to 4 due to normal errors in the chemistry analyses. In accordance with these ranges of probable errors, error bands of ±1 and ±4 are indicated in Figure 4. As can be seen, most of the data points and the predicted values are inside the ±4 band.

Table 3 shows the predicted variations in H_2S removal rates due to variations in separate parameters including vent rate, inlet H_2S concentrations, and inlet NH_3 expected during the field test at The Geysers. Table 3 also shows the calculated effect on H_2S removal rate measurements due to estimated errors in the chemistry analysis techniques used during The Geysers tests.

III. Heat Transfer Performance

A. Predicted Performance Capital cost of the heat exchanger can be related almost completely to its size as defined by its surface area. The required surface area (A) is directly proportional to the heat load (Q), and inversely proportional to the heat transfer coefficient (U) and the temperature driving force (ΔT), as expressed below:

$$A = \frac{Q}{U \Delta T} \qquad (1)$$

For a given application, Q is essentially fixed by the amount of steam required to supply the turbine and ΔT is fixed by considering the allowable drop in steam pressure and temperature upstream of the turbine. The U value, however, is dependent on heat exchanger size and design.

The heat exchanger test unit at The Geysers and heat exchangers used in the cost models for the commercial scale cost estimates, presented in the following section, are vertical tube evaporators (VTE) as shown in Figure 1 with smooth tubes. Alternative heat exchanger designs with predicted improved heat transfer performance have been reviewed. These alternative designs are the VTE with doubly fluted tubes and the horizontal tube evaporator (HTE) with smooth tubes. Representative U values for these three design options have been estimated for this application by extrapolating data obtained in other applications, using a consistent theoretical approach, so that these U values can be used to compare heat transfer performance of these three options.

Doubly fluted tubes were developed by the desalination industry to increase the heat transfer coefficients over the smooth-tubes VTE unit. The tubes are fabricated with ridges both on the inside and outside tube surfaces. A number of different configurations are used, and a typical design is shown in Figure 6.

The major advantages of the doubly fluted tubes are that the condensing heat transfer coefficientis greatly improved. This is due to surface tension effects that cause most of the condensate to flow through the channels, leaving the ridge area with a very thin condensate layer that has a very low resistance to heat transfer.

In the HTE spray-film unit, the geothermal steam is introduced on the tubeside and condensate on the shellside. The condensate would be sprayed over the outside of the tubes, and the steam would condense within the tubes and flow out of the ends. Figure 7 shows an HTE configuration for the heat exchanger process.

The major advantage of the HTE is that the heat transfer coefficient is significantly improved over a smooth tube VTE design even while using smooth tubes in the horizontal unit. The primary gain is due to the improved condensing side coefficient, because of a reduced overall film thickness.

Table 4 shows the comparative estimated U values and surface area requirements for commercial applications of the three heat exchanger options discussed above. The test unit at The Geysers and the heat exchangers used in the commercial scale cost models discussed in the following section were VTE units, with smooth tubes. The estimated U value for this design option shown in Table 4 is 740 Btu/($h \cdot {}^\circ F \cdot ft^2$), while a conservative lower U value of 600 Btu/($h \cdot {}^\circ F \cdot ft^2$) was used in the commercial scale capital cost calculations discussed in the following section.

In Table 4 the comparison of data between VTE units with smooth tubes and those with fluted tubes indicates that there is very little difference in performance within the level of accuracy of this estimate. The anticipated improvement in the overall U value for fluted tubes was minimized by the high thermal conductivity of 304 SS which resulted in large tube wall resistances for the fluted tube. The same conclusions apply to titanium--another acceptable tube material for this application-- since its conductivity is about the same as that of 304 SS. The HTE smooth tube design appears to be significantly different in heat transfer performance when compared to VTE units. The required heat transfer area for an HTE unit is about two-thirds of that for the vertical tube exchangers.

The economic comparison depends on the unit cost per surface area of the three design options. With the understanding that the unit cost of fluted tubes will be somewhat higher than smooth tubes, it becomes obvious that the capital cost of the VTE with fluted tubes will probably not be lower than that of the VTE with smooth tubes. On the other hand, a significant capital cost savings is possible with the HTE because of the much less surface area required.

B. Test Unit Results The measured U values are shown plotted with respect to vent rate and ΔT in Figure 8. These values ranged from 333 to 788 Btu/(h·ft^2·°F) with an average of 576 and a standard deviation of 85. As can be seen in Figure 8, correlations between the measured U values and the vent rate and ΔT can not be obviously shown from the field data. Intuitively, the U value would be expected to increase as either the vent rate or ΔT was increased due to a decrease in the noncondensable blanketing effect, either by purging the shellside of the heat exchanger or by increasing the turbulence on the shellside because of the higher flow rates associated with the higher ΔT.

Throughout the test program the measured U values were consistently lower than predicted values. In an attempt to explain these lower values, the test unit heat exchanger was chemically cleaned to determine if film or scale formation on the heat transfer surfaces was causing the lower measured U values. No conclusive difference could be seen after cleaning, thus implying that scaling was not a significant problem.

It is believed that a significant factor leading to the low measured U values was that the blanketing effect of noncondensable gases was relatively high because of the small size of the test unit; this will have a relatively much smaller influence on large units. However, the larger part of the discrepancy between measured and expected U values was due to leaks of condensate from the top of the tubesheet, through the tubesheet seal area, into the evaporator sump. These leaks were discovered towards the end of the test program,and were due to an inadequate seal design that has been corrected. Such leaks do not affect the performance of the unit in any way, but result in low measured values for U since this value is calculated on the basis of the amount of condensate transferred externally from shellside to tubeside. As the pressure difference from the shellside to the tubeside of the heat exchanger increased, as was the case during the test runs at high ΔT values, the leakage rate also increased, thus resulting in even lower measured U values. In reality, based on theory and on the results of most of the tests, it is believed that the actual U value was quite constant over the range of test conditions.

IV. Cost and Performance Estimates for Commercial Scale Units

A. Cost Estimates Figure 9 is an example of a commercial scale H_2S abatement system that would be appropriate at both a dry steam resource such as The Geysers and a liquid dominated resource where liquid is flashed to produce steam. This system consists of a two-stage heat exchanger process for removing H_2S and other noncondensables and a Stretford plant for disposal of the removed H_2S. Geothermal steam enters the first-stage heat exchanger unit and is separated into clean steam and a small vent gas stream. The clean steam is sent to the turbine and the vent gas goes to the second stage. Blowdown from and makeup to the first-stage sump are controlled to limit the buildup of various chemical species in the tubeside condensate.

In a manner similar to that of the first stage, the stream entering the second stage is also separated into clean steam and a vent stream. Clean steam from the second stage is used to supply the after-turbine condenser vacuum system and the Stretford process. Vent gas from the second-stage heat exchanger goes to the vent condenser. The second-stage sump also has provisions for blowdown and makeup.

The vent condenser cools the second-stage vent gas down to temperatures required for discharge to a Stretford unit, normally around 120°F. The condensate formed in the condenser is injected into disposal wells or discarded by some other means.

Table 5 presents a cost summary for a commercial scale system as shown in Figure 9, sized for a typical 55-MW geothermal power plant unit. The costs shown are based on 1979 dollars and the design bases for these costs are shown in Table 6. Table 7 summarizes the major equipment items included.

The capital cost for the heat exchanger process system is estimated at \$5.6 million. Based on vendor quotes, a 2.5-ton-per-day Stretford unit cost is \$2.6 million, giving a total abatement system cost of \$8.2 million. Total direct annual operating costs were \$425,000 or 1.0 mill/kWh. With annualized capital charges of 18.5 percent, the total operating and capital costs are \$1,945,000 or 4.4 mills/kWh.

The commercial cost estimates presented above are based on a Stretford unit being used for ultimate disposal of the removed H_2S. Under proper geologic conditions, however, one alternative to this approach is to reinject the high pressure H_2S-rich vent gas into an outlying geologic formation which has little or no interaction with the producing field. If this were done, the substantial capital and operating costs associated with the Stretford unit could be avoided.

B. Power Production Performance Effects

The heat exchanger process could result in a slight loss in power production because of the vented steam and the lower pressure of the steam which goes to the turbine. However, since the process removes all of the noncondensable gases ahead of the turbine, the demands of the steam jet air ejector system are reduced and enough clean steam can be obtained from the second-stage heat exchanger to drive the ejectors. The potential power which can be produced per unit of wellhead steam must take all of these factors into account.

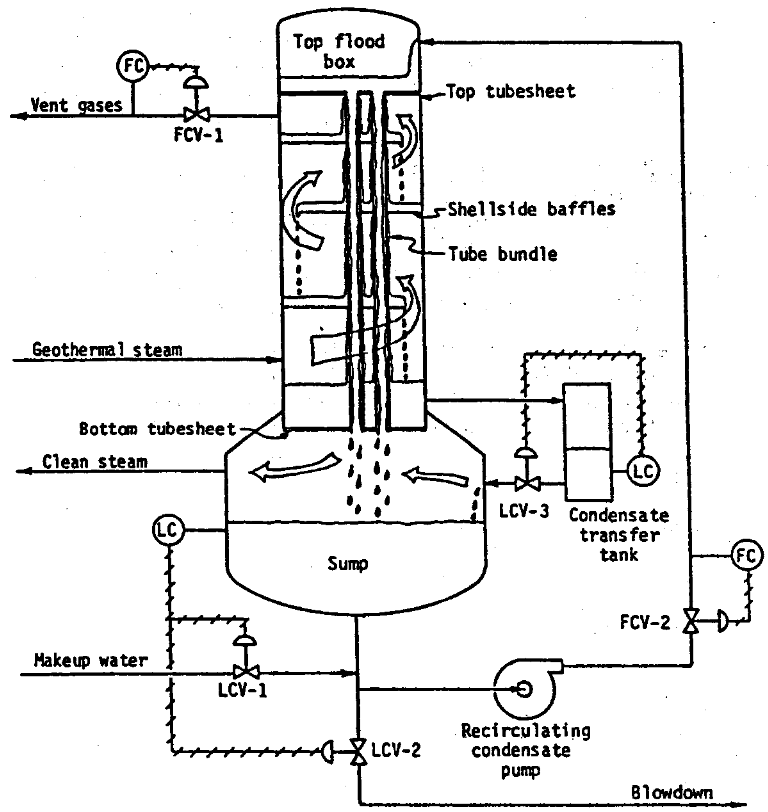
The amount and condition of the steam going to the turbine per mass unit of steam delivered to the heat exchanger process depend on the vent rate and ΔT of the first-stage exchanger. As the vent rate increases, the amount of steam available to the turbine decreases. As the ΔT increases, the temperature and pressure of the clean steam decreases so that less power can be derived per unit of steam. Calculations of theoretical power were done for various ΔT's and vent rates. The results are presented in Figure 10 which shows the relative power produced by the steam from the heat exchanger process versus using 350°F saturated wellhead steam directly. The figure is based on typical Geysers ratios of 95 percent of the wellhead steam going to the turbine and 5 percent going to the ejectors for the case without the heat exchanger process. If ejector requirements are different, then a different set of curves would apply. Calculations show that 2 percent going to the ejectors may be sufficient at The Geysers with the heat exchanger process upstream of the turbine. When the upstream pressure losses are considered, such as those caused by turbine throttle valves, the reduction in power output due to the heat exchanger process may be reduced. The selection of the vent rate, which depends on the steam composition and H_2S removal requirements, has a large effect on the relative power production. To summarize, the effect of the heat exchanger process on power production depends on the combined results of the design factors discussed above which will vary with each specific application. In certain situations the addition of the heat exchanger process could result in no net power loss at all and, in some special cases (low ΔT's and low vent rates), a net power increase might be conceivable.

Varying the ΔT affects both the heat transfer area and power production. For example, reducing ΔT increases the heat exchanger area required but also increases power production. As a result, ΔT must be optimized by balancing capital cost against power production. Figure 11 shows the effect of changing ΔT on capital costs for a 55-MW system. The base case used in Figure 11 is the commercial scale cost estimate previously discussed. A 0.6 power law dependence based on surface area is adopted based on normal process industry scale-up cost estimating techniques.

Changes in the heat transfer coefficient also affect the heat transfer area. Different designs such as fluted tubes or a horizontal tube spray film exchanger, as discussed earlier, could provide higher heat transfer coefficients. The cost estimate developed was based on a 600 Btu/(h·ft^2·°F). This is considered a conservative estimate based on pilot plant data. Problems with leakage in the pilot plant exchanger likely have caused calculated values of the heat transfer coefficient to be low. For this reason, Figure 11 includes capital cost comparisons for design heat transfer values of both 600 and 1000 Btu/(h·ft^2·°F). Knowing the cost of power, load factor, equipment design life, and interest rate, the heat exchanger could be designed to run at whatever ΔT gives the lowest combination of capital and operating costs.

V. References

1. Glenn Coury and R. A. Babione (1981), "A Heat Exchanger Process for the Removal of H_2S Gas from Geothermal Steam--Final Report," Prepared for Electric Power Research Institute, Palo Alto, California, March 1981.



FC - Flow controller

LC - Level controller

FCV - Flow control valve

LCV - Level control valve

Figure 1. Heat Exchanger Process Vertical Tube Evaporator With Baffled Shellside Configuration.

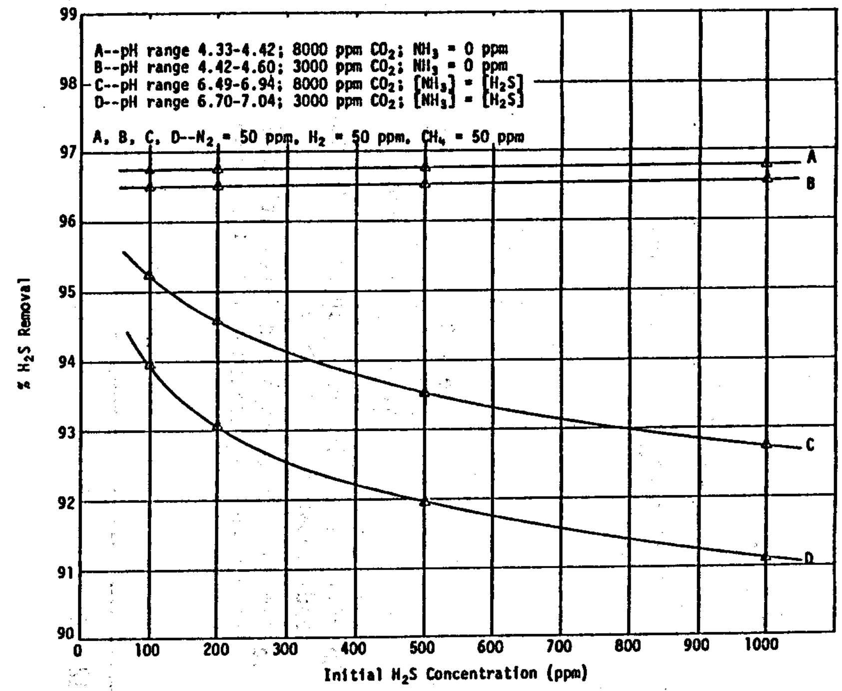


Figure 2. Predicted H_2S Removal at 98% Condensation

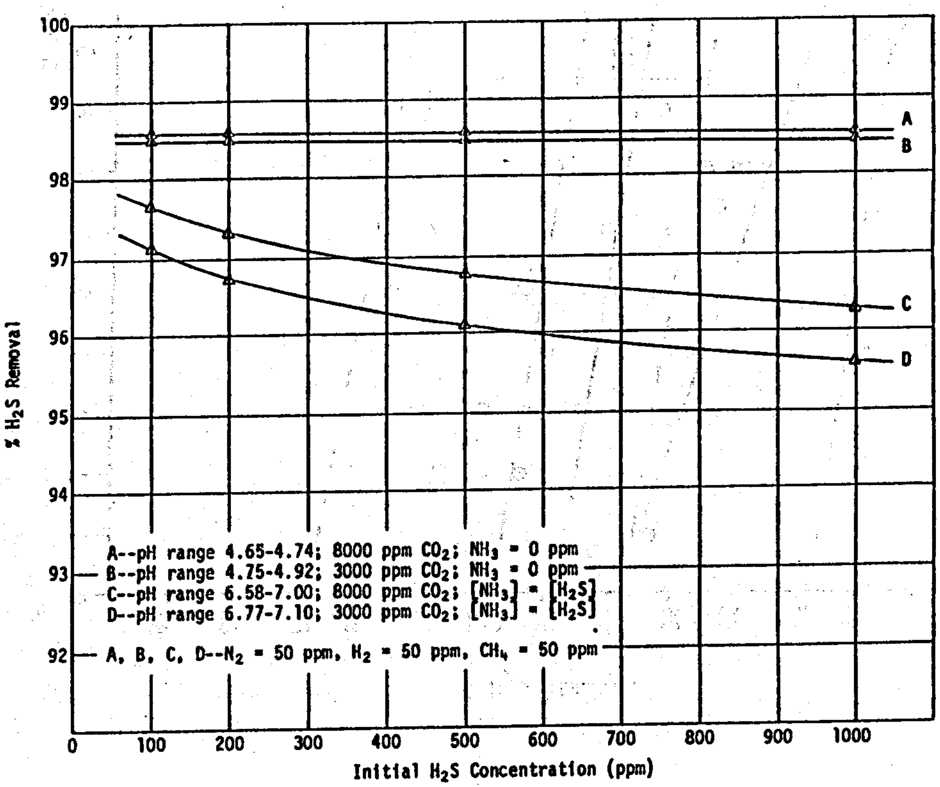


Figure 3. Predicted H_2S Removal at 90% Condensation

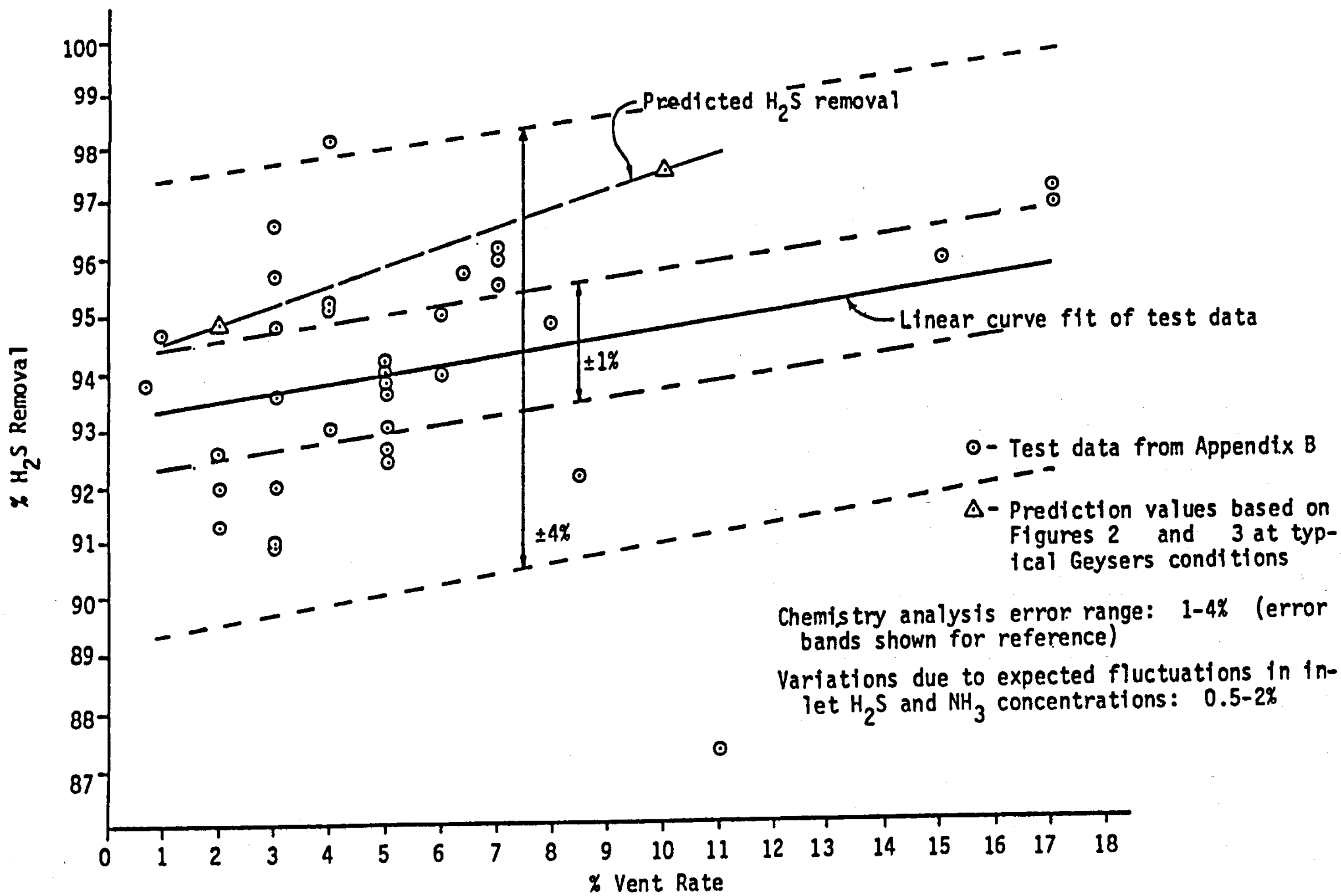


Figure 4. Test Unit Performance: H_2S Removal Versus Vent Rate

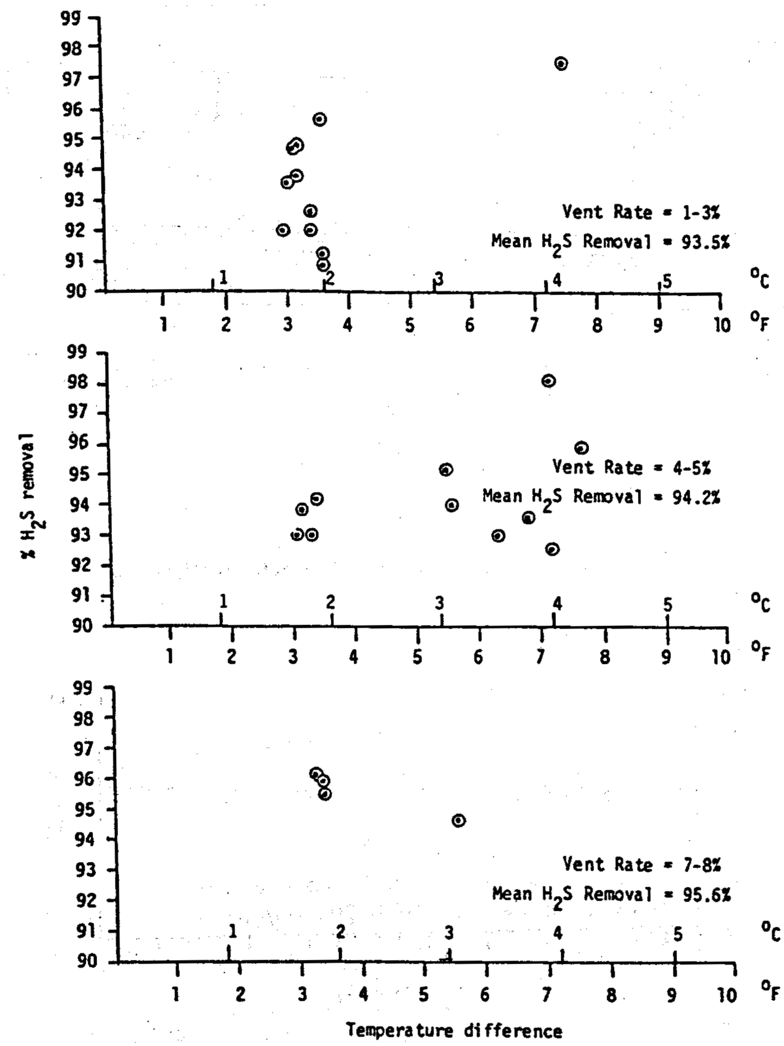


Figure 5. Test Unit Performance: H_2S Removal Versus Temperature Difference

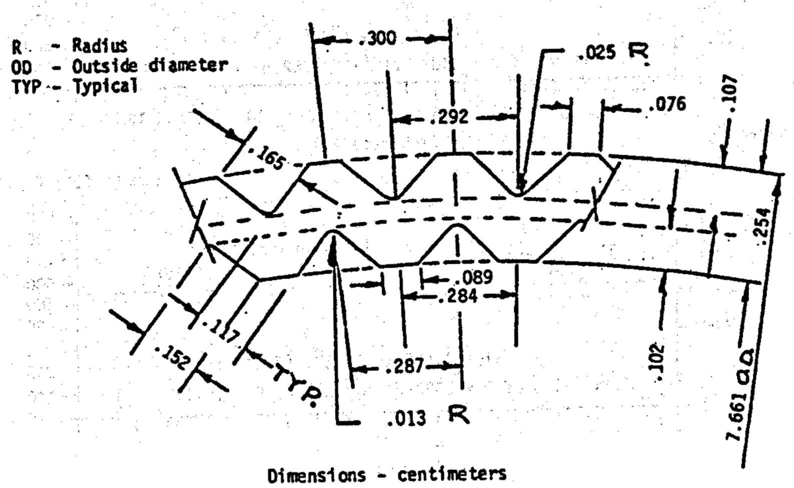


Figure 6. Cross Section of a Doubly Fluted Heat Exchanger Tube

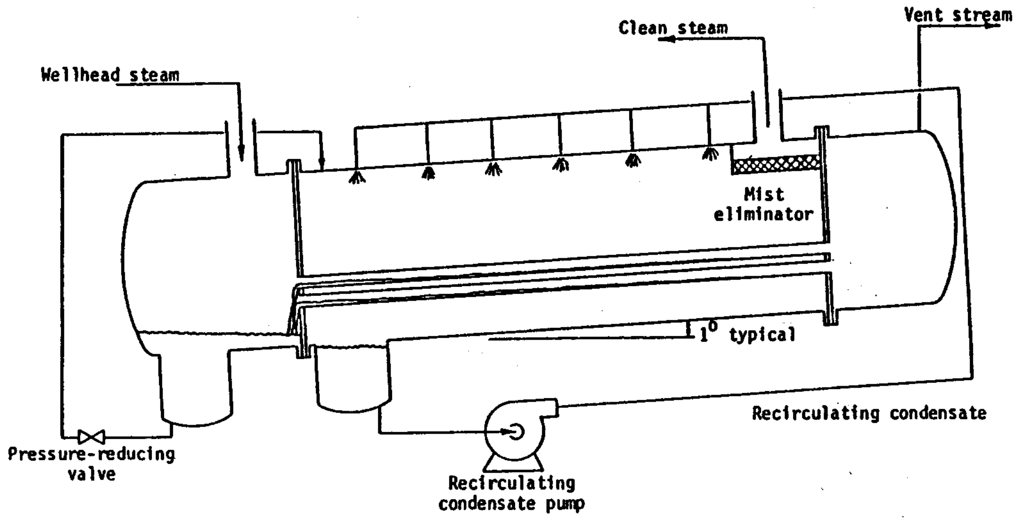


Figure 7. Horizontal Tube Evaporator Configuration

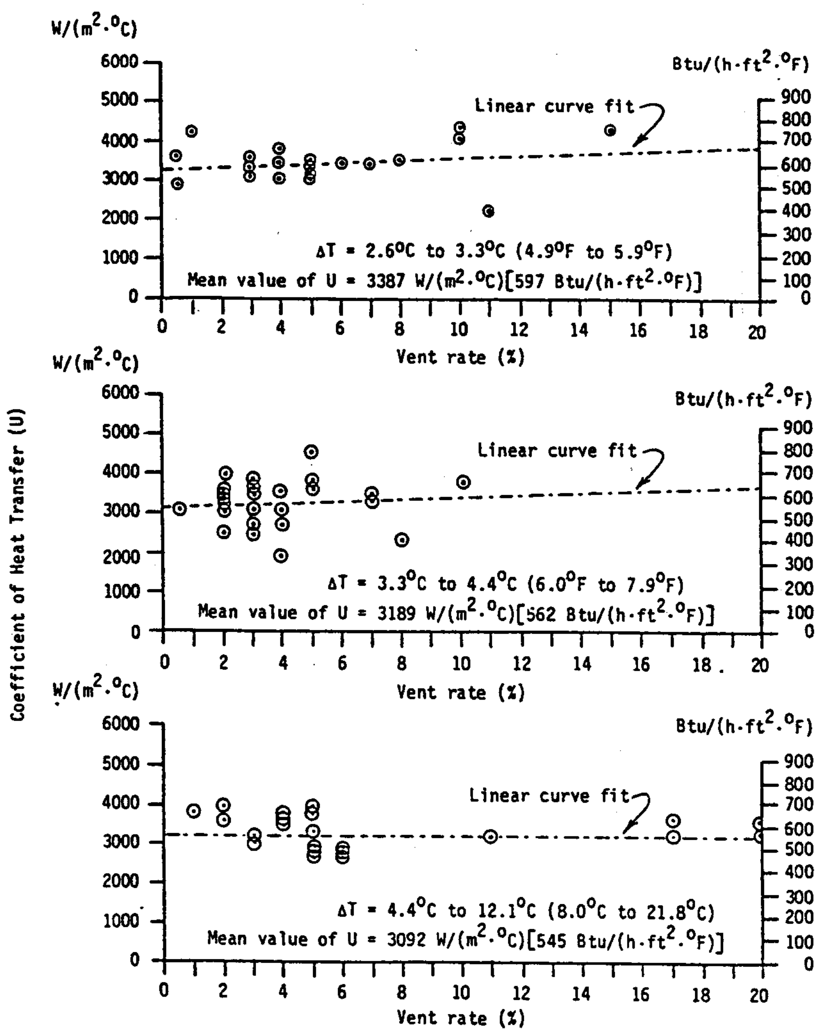


Figure 8. Test Unit Performance: Coefficient of Heat Transfer Versus Vent Rate

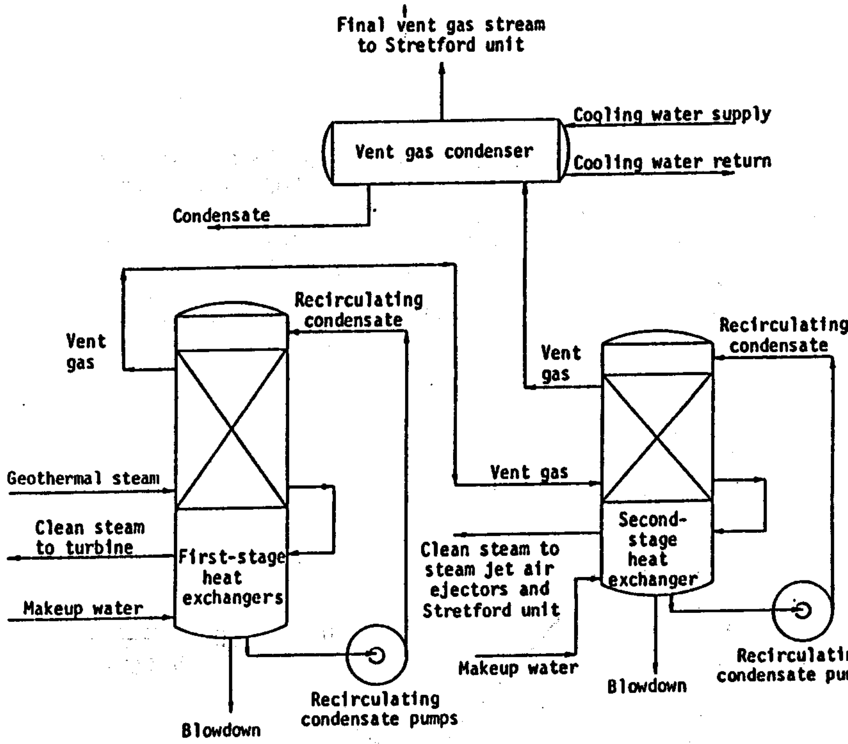


Figure 9. Process Flow Diagram, Commercial-Scale Heat Exchanger Process H_2S Abatement System

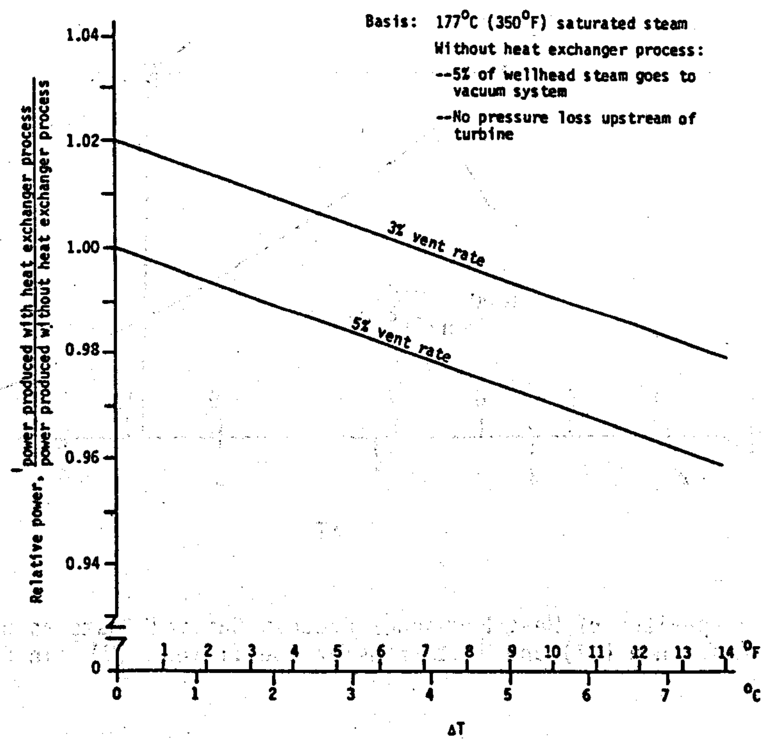


Figure 10. Comparison of Power Production Using Heat Exchanger Process as a Function of ΔT and Vent Rate

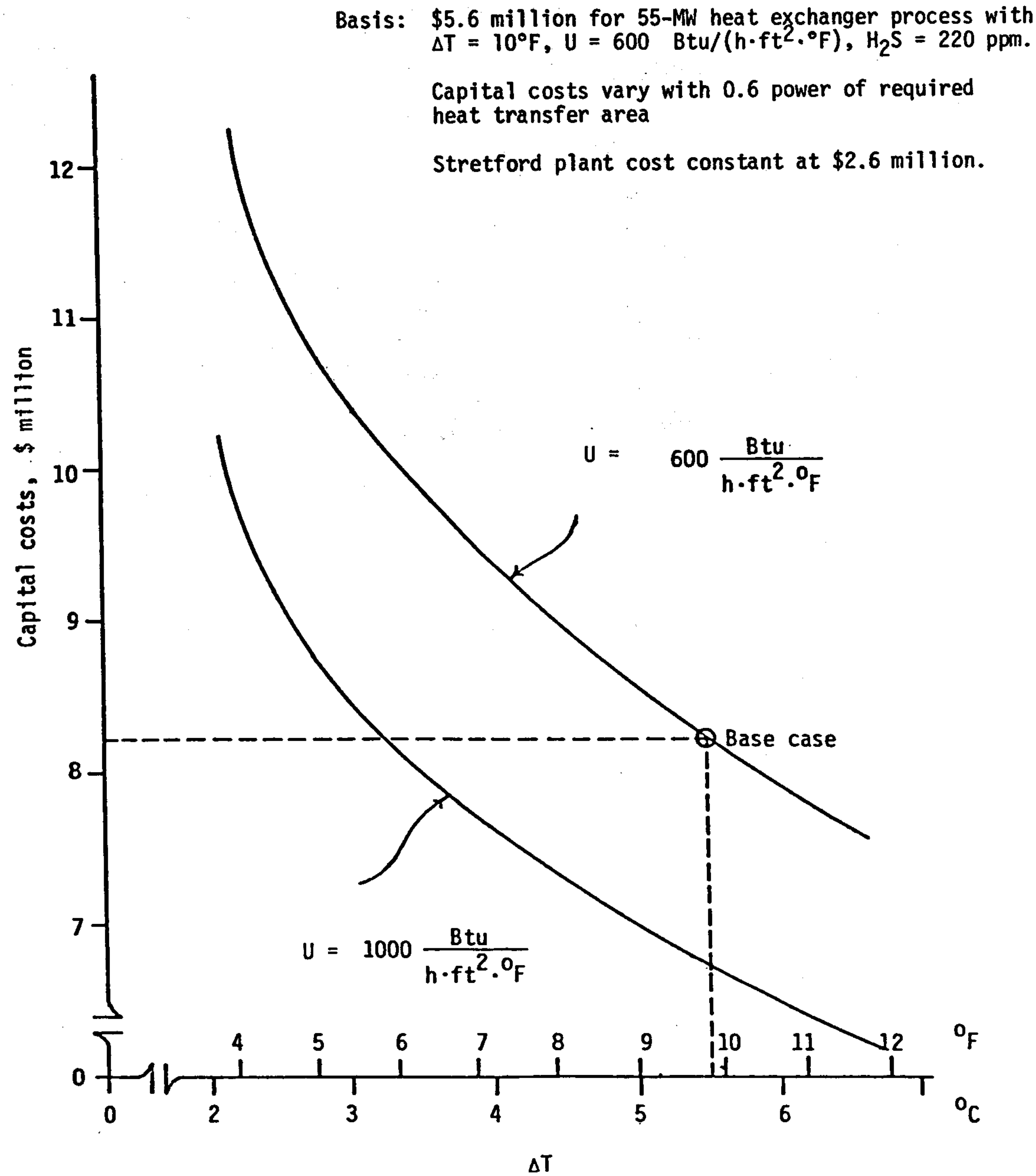


Figure 11. Comparison of Heat Exchanger Process Capital Costs as a Function of Temperature Difference (ΔT) and Heat Transfer Coefficient (U) in First-Stage Heat Exchanger

TABLE 1

STEAM COMPOSITIONS AT THE GEYSERS GEOTHERMAL FIELD

Component	Average Concentration (ppm)	Range (ppm)
CO_2	3000	300 - 6000
H_2S	220	70 - 570
NH_3	100	10 - 330*
CH_4	200	
H_2	50	
N_2	50	
B	20	
Total	3640	

*Total concentration of NH_3 ranges from about 50% to about 100% of the H_2S concentration for a particular set of conditions.

TABLE 2

H_2S REMOVAL VS. INLET H_2S AND NH_3 CONCENTRATIONS

TEST DATE	1/18/80	1/22/80	1/23/80	1/24/80	1/25/80
INLET H_2S (PPM)	722*	801*	317	380*	310
INLET NH_3 (PPM)	171	173	632*	228*	120
INLET CO_2 (PPM)	4,410	4,040	3,093	4,022	3,991
INLET RATIO OF NH_3:H_2S	0.24	0.22	1.99	0.60	0.39
CLEAN STEAM H_2S (PPM)	55	46	23	19	18
CLEAN STEAM NH_3 (PPM)	173	115	254	155	89
% VENT	5	6	5	6	5
ΔT (^oF)	11	10	11	9	10
H_2S REMOVAL (%)	92	94	93	95	94
NH_3 REMOVAL (%)	0	34	60	32	26
PREDICTED H_2S REMOVAL (%)	97	98	95	97	97

* CONCENTRATIONS INCREASED ARTIFICIALLY BY GAS INJECTION

TABLE 3

COMPARISON OF EFFECTS ON MEASURED H_2S REMOVAL VALUES

Process Parameter or Analysis Error	Process Parameter Range or Error Assumptions	Predicted Variation of Measured H_2S Removal Values	Reference
Vent rate	2-10% of inlet flow rate	∿ ±3 to 4%	Figures 2 and 3
Inlet H_2S concentration	150-350 ppm	∿ ±0.5 to 1%	Figures 2 and 3
Inlet NH_3 concentration	50-100% of inlet H_2S concentration	∿ ±1 to 2%	Figures 2 and 3
Chemistry analysis error	*	∿ ±1 to 4%	*

* The chemistry analysis errors are assumed to be ±5% for the inlet steam H_2S concentrations and ±5 ppm for the clean steam H_2S concentrations. This is based on communications with PG&E personnel who are familiar with these techniques and also on the standard deviation of the measured concentrations. A detailed discussion is presented in Reference 1.

TABLE 4

COMPARISON OF PREDICTED HEAT EXCHANGER HEAT TRANSFER PERFORMANCE

Unit	Tubes	Overall Heat Transfer Coefficient-U $Btu/(h \cdot ft^2 \cdot {}^oF)$	Total Heat Surface Area-A Ft^2
VTE	Smooth	740	120,000
VTE	Fluted	780	110,000
HTE	Smooth	1100	80,000

1. Tubes - 304 stainless steel - 2 in. OD x 0.049 in. wall thickness
2. $\Delta T = 10^oF$
3. $Q^* = 871 \times 10^6$ Btu/h

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*Based in flow requirements of 1.1×10^6 lb/h of 350^oF saturated steam for a typical 55-MW geothermal power plant unit.

TABLE 5

H_2S ABATEMENT SYSTEM COST SUMMARY IN 1979 DOLLARS

Capital Investment:	
Heat exchangers	$2,900,000
Pumps	100,000
Piping, valves, controls, insulation	900,000
Major equipment cost	3,900,000
Construction @ 20% of major equipment cost	780,000
Subtotal	$4,680,000
Engineering and fees @ 20%	940,000
Total capital cost -- heat exchanger process	5,620,000
Stretford unit	2,600,000
Total capital cost H_2S abatement system	$8,220,000
Annual Cost of Investment:	$1,520,000
Annual Operating Costs:	
Power @ 4.5¢/kWh	$ 53,000
Operating and maintenance (heat exchanger process)	112,000
Operating and maintenance (Stretford unit)	260,000
Total	$ 425,000
Operating costs (mills/kWh)	1.0
Total annual capital and operating costs	$1,945,000
Total annual capital and operating costs (mills/kWh)	4.4

TABLE 6

BASES FOR H_2S ABATEMENT COST SUMMARY

Generating Capacity Basis -- 55 MW

Supply Steam to First Stage H.X. - 1.1×10^6 lb/h, $350^{\circ}F$ saturated, 220 ppm H_2S

Overall H_2S Removal -- 95 percent

On-line Time -- 8000 hours per year

Process H.X. Design -- VTE smooth tube

Process H.X. Materials of Construction -- 304 S/S

First-Stage H.X. U Value -- 600 $Btu/(h \cdot ft^2 \cdot {}^{\circ}F)$

First-Stage H.X. Condensing Rate -- 95 percent

Second-Stage H.X. Condensing Rate -- 50 percent

Vent Gas Condenser Temperature -- $120^{\circ}F$

Stretford Unit Production -- 2.5 tons of sulfur per day

Annualized Capital Costs -- 18.5 percent of total plant cost

H_2S Removal Process O&M Costs -- 2 percent of removal plant cost

H_2S Disposal Process O&M Costs -- 10 percent of disposal plant cost

TABLE 7

REMOVAL PROCESS PLANT MAJOR EQUIPMENT LIST

First-Stage Heat Exchangers	-- 3	33 percent units
Second-Stage Heat Exchanger	-- 1	100 percent unit
Vent Gas Condenser	-- 1	100 percent unit
First-Stage Circulation Pumps	-- 4	33 percent units
Second-Stage Circulation Pumps	-- 2	100 percent units

PILOT PLANT FOR NONCONDENSABLE GAS REMOVAL BY UPSTREAM REBOILING

RP1197-4
(Proposed)

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Introduction. Geothermal steam at The Geysers contains non-condensable and particulate materials which can be costly to deal with. There are direct effects such as deposition of borates inside steam turbines and the equipment or chemicals needed for H_2S removal. There are also indirect costs such as that for replacement power when units require maintenance, or the derating of units when side effects of some mitigation measure interfere with plant design. PGandE is studying the Coury Process in the course of a continuing search for cheaper and more flexible ways of dealing with these problems.

The preceding paper in this conference is an account of laboratory-scale work done on the process. Proposed as the next development step is a 42,000 lb/hr pilot plant at The Geysers.

Status. Conceptual design of the pilot plant was done last year by Coury and Associates. PGandE and C&A expect soon to begin detailed design of the pilot plant, with costs to be shared by EPRI and PGandE. The procurement and construction schedule have not yet been established.

Importance. The Coury approach is attractive because it would have minimum impact on the power plant proper and should have low operating costs. The equipment is not highly integrated with the power plant. It could be retrofitted to existing units without the long outages that go with surface condensers. It has potential for reliable, simple and non-interfering operation. Questions requiring evaluation are the size of capital costs, the loss in thermodynamic availability of the energy processed, and the fact that H_2S is only diverted, not converted; an additional sulfur recovery or disposal step is required.

Objectives. The pilot-scale study will have as its objectives:

- to determine overall heat transfer coefficients and removal efficiencies under various operating conditions,
- to accumulate data necessary for sizing the heat exchangers for a full-scale application,
- to develop information necessary to predict capital and operating costs,
- to evaluate equipment servicability for unattended operation,
- to determine the behavior of the system during upsets and transients.

Conceptual Design. The conceptual design and test program are based on siting at Unit 13. The low levels of non-condensable gases at Unit 13, coupled with the inclusion of a chemical injection system will make possible testing over a broad range of gas concentrations. Furthermore, if most of the gas reaching the condenser/reboiler is injected gas, fluctuations in steam-field gas concentrations will be attenuated, and the sampling and analysis problems will be eased.

In order to utilize the steam fed to it, the pilot plant is sized to supply the unit's main condenser gas ejectors. Provision is made to supply the gas ejectors with untreated steam when the pilot plant is unavailable

A second stage condenser/reboiler is included in the pilot plant to simulate the control situation of the full-scale design. The purpose of a second stage in a commercial-scale plant is to recover steam (representing water and energy) which would otherwise be lost in the vent-gas stream from the first stage.

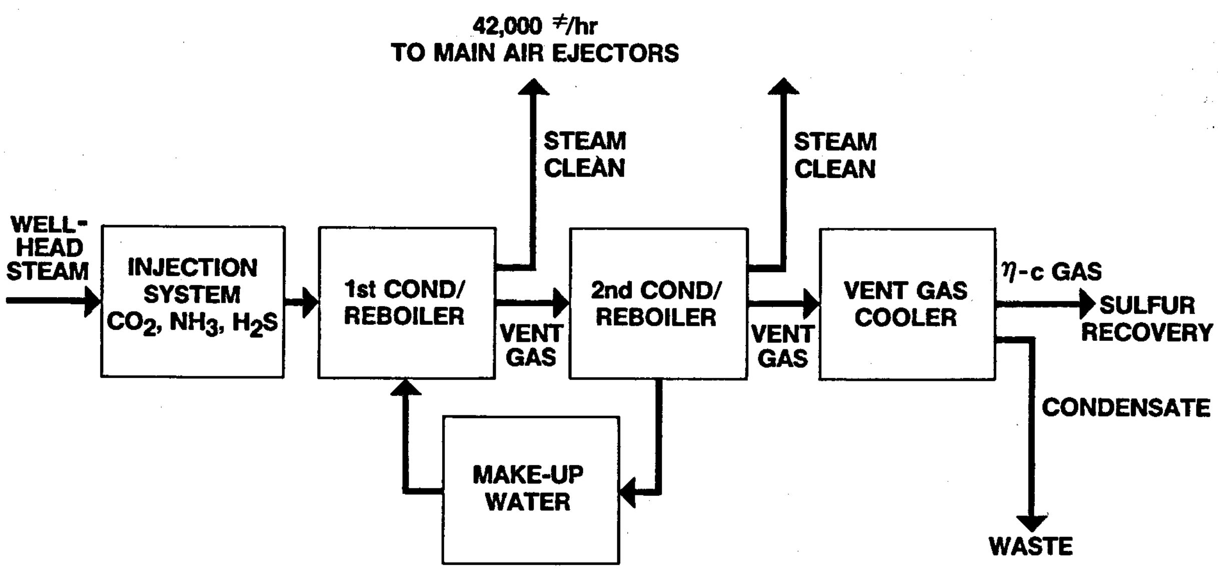
TEST PROGRAM. The objective is to make heat and mass balances on the vent gas cooler, the two condenser/reboilers, and the overall system. Flow rates and concentrations of H_2S, CO_2, and NH_3 will be required on nine streams.

Steam flow rate, reboiler recirculation rate, and rate of vent gas withdrawal will be treated as independent variables.

Present plans call for manual sampling and chemistry, sending liquid-phase ammonium analyses to an off-site laboratory and doing other analyses in the field.

The accompanying figure indicates the major systems of the pilot plant.

Coury Process Pilot Plant



RADIAL INFLOW TURBINE UPDATE

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Los Angeles, CA 90064 (213) 477-3083

This study was started in association with EPRI back in 1977, initially to create radial inflow turbine designs based on experience and applicable to a broad range of hot water geothermal brines. The brine heat is used to boil a hydrocarbon mixture of isobutane and isopentane; the gas is then expanded through the turbines.

Having a very broad application, the original concept had two back-to-back turbines and a single wheel turbine. This permitted a very wide range of operation and could be simplified to suit a particular application.

What I am about to give you is an update on the progress in the radial inflow turbine field. The Heber application has varied in concept, but the latest has been to make use of the varying condensation temperature possible with varying dewpoint temperature. As Thom Page of San Diego Gas and Electric pointed out, this saves 16% on brine usage and some capital saving.

This philosophy has changed the design point appreciably so we are able to look at a very simple construction, aligning very well with machinery already manufactured and tested,

Figure 1 shows the layout of such a turbine. The gas, entering via the connection at the top into an annulus, travels or passes through variable nozzles which generate an angular swirl and thence enters the turbine where the angular swirl is removed and some further expansion takes place. With varying condensing temperature, an ability is required to operate with varying back pressure and with varying energy drop across the machine.

A multi-stage machine soon gets badly mismatched between inlet and discharge stages. Working with fixed speed and variable speed gas turbines for many years has given the author understanding in this area. This is why we see multiple spool gas turbines in existence today with each spool rotating at its own speed. A multi-stage turbine would work quite well over a large enthalpy range; that is energy drop across the machine if it had variable nozzles for each stage. We have and do adapt this solution at Rotoflow. In this case, because of the large enthalpy capacity of the radial turbine, only a single radial stage is needed. The next question to be asked is what happens in the machine with varying discharge pressure.

1. The energy drop changes.

2. The volume changes.

How does the radial inflow turbine operate under these conditions?

First, let's look at flow. All Rotoflow turbines are equipped with variable inlet nozzles which completely removes the necessity for an upstream throttling valve; no energy is wasted as it would with an upstream throttling valve, and in order to maintain control, there is no necessity for any pressure drop across any upstream throttling valve. The variable inlet nozzles do all the controlling, and all the kinetic energy goes into power conversion.

To illustrate this, Figure 2 shows how a radial inflow turbine handles flow versus what occurs with an axial multi-stage unit with upstream throttling.

The latter data is taken from the EPRI report, ER 513. The dotted line shows the excellent efficiency/flow characteristic obtained from data recently received from N.A.S.A. on one of our 26-inch turbines. This is probably the most complete set of data run on one of these machines.

The reason for this excellent flow/efficiency characteristic of the radial turbine is shown in Figure 3. Put very simply, at partial flow conditions, the radial inflow turbine develops a dead zone towards the center with the gas being concentrated to the outside and develops close to its correct discharge conditions. The N.A.S.A. data confirms this well.

The next question is what happens with the varying energy drop associated with varying condensation temperature.

For the Heber application, we are using a mixture of isobutane and isopentane as the Rankine cycle gas. The design back pressure is 56 lbs. per square inch absolute, and at this condition the gas from the nozzle has a velocity of 965 ft/sec, and the tip speed of the turbine is 896 ft/sec.

The relative velocity between the gas and the turbine wheel tip is small, permitting radial entry at low velocity which is partly the reason why it can handle condensing streams and commonly does (0-52% liquid at the discharge).

When the back pressure reduces, the pressure falls and volume increases. This results in some increase in pressure drop across the wheel, but let us ignore this compensating factor for a minute and consider what happens with all the changes in energy taking place across the nozzles.

In the Heber application, 10% change in overall enthalpy is equivalent to a change in wet bulb from 80°F to 55°F and a change in back pressure ratio from 7.6 to 10.6 to 1.

With the radial inflow turbine, these changes are equivalent to a velocity change across the nozzles of approximately 90 ft/sec relative to the turbine and corresponding to less than 1/2% loss. This loss would be far larger in an axial turbine, a maximum of 5%, due to the higher relative velocity between gas and blading.

These theoretical studies have recently been confirmed in the very extensive work on the 26-inch Rotoflow turbine carried out at the National Aeronautics and Space Administration facility at the Lewis Laboratories. This turbine demonstrated 87% efficiency at 11,100 HP and a pressure ratio of 6:1.

In a 56-inch turbine, this is equivalent to 56,000 HP in blade loading, and it demonstrated the very flat flow efficiency curve shown in Figure 2. We believe the only turbine capable of fully utilizing the variable back pressure concept to be the radial inflow turbine.

We have been questioned on our choice of materials, but this is certainly flexible. The significant advantage of radial inflow turbines is the very large temperature drop across the nozzles, 98°F, which means average turbine temperatures of 175°F. This is cool enough for us to use already proven materials in the size range for a 90,000 HP machine.

Figure 4 shows a machine built for the Air Force test facility at Tullahoma, Tennessee; it contains a 53-inch wheel using A355 alloy and has been tested to 5,000 rpm. In comparison, the Heber unit will run at 3,600 rpm.

This is not just one unit. Figure 5 shows an early picture of 5 machines on site. This is part of a huge facility for testing gas turbines and we expect considerable feedback from these machines such as we have obtained from N.A.S.A.

In terms of power loading, we have 12 turbines operating in Algeria with an inlet pressure of about 1400 psi and a power density per unit blade area equivalent to 100,000 HP in a 53-inch machine.

Sealing systems have been demonstrated. Figure 6 shows the turbine used in a closed loop system which demonstrates self-sustained ocean thermal energy conversion, a world's first!

All these machines and a thousand others like them operating in every major country in the world are built on similar principles utilizing the many patents originated by Dr. Swearingen.

All these machines utilize a system in which the shaft, bearings, wheels, and seals are assembled in one unit that can be rapidly changed as a cartridge unit. A 10,000 HP machine loses $300,000/day in lost product for every day it is shut down. So, we do understand the need for minimum down time and much attention has been given to this. Our average in unscheduled down time is one day in 5 years.

Figure 7 shows such a cartridge unit. It has a 53-inch wheel, high speed electro-hydraulic nozzle controls, which will handle load rejection with ease. The alternative to variable inlet nozzles is a very large inlet valve closing in a small fraction of a second. This type of valve is unproven at this time and may require considerable development for repeated operation.

For a geothermal application, we have considered thrust balance, turbine stresses and low cycle fatigue. The bearings will take 40,000 lbs. of thrust load, which is excellent for two reasons. First, the axial load that occurs with an earthquake having one-half the force of gravity in the axial direction is 20,000 lbs. which is equal to one-half the weight of the generator rotor and turbine (the generator having no thrust bearings). Second, pressure variations have been calculated to produce 5,000 lbs. of axial thrust with a single turbine and balanced in a back-to-back configuration.

Copies of a final report containing more detailed information have been made available by EPRI to interested parties.

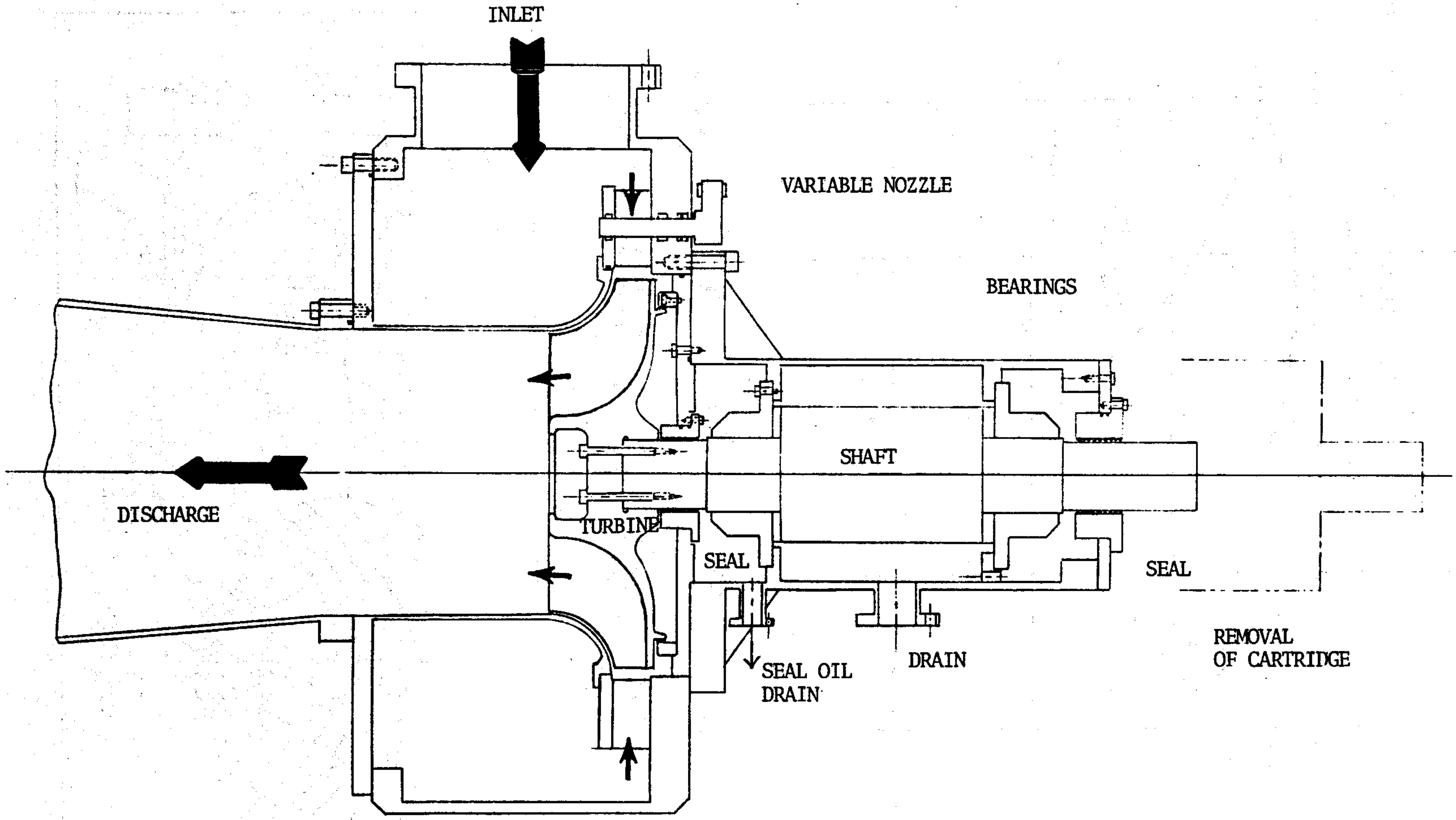

INLET
VARIABLE NOZZLE
BEARINGS
SHAFT
DISCHARGE
TURBINE
SEAL
SEAL
SEAL OIL
DRAIN
DRAIN
REMOVAL
OF CARTRIDGE

FIG. 1

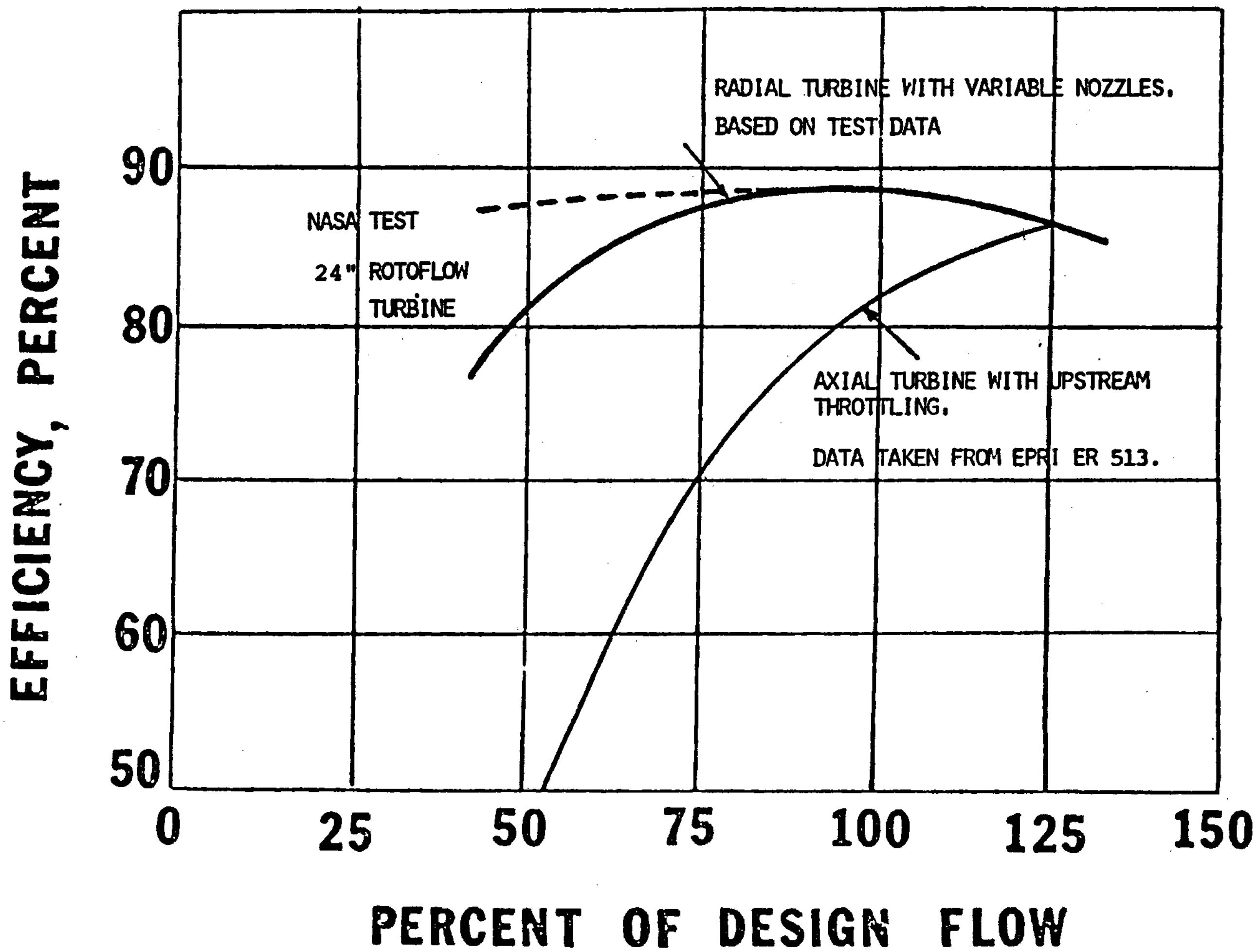

RADIAL TURBINE WITH VARIABLE NOZZLES.
BASED ON TEST DATA
NASA TEST
24" ROTOFLOW
TURBINE
AXIAL TURBINE WITH UPSTREAM THROTTLING.
DATA TAKEN FROM EPRI ER 513.
EFFICIENCY, PERCENT
90
80
70
60
50
0
25
50
75
100
125
150
PERCENT OF DESIGN FLOW

FIG 2

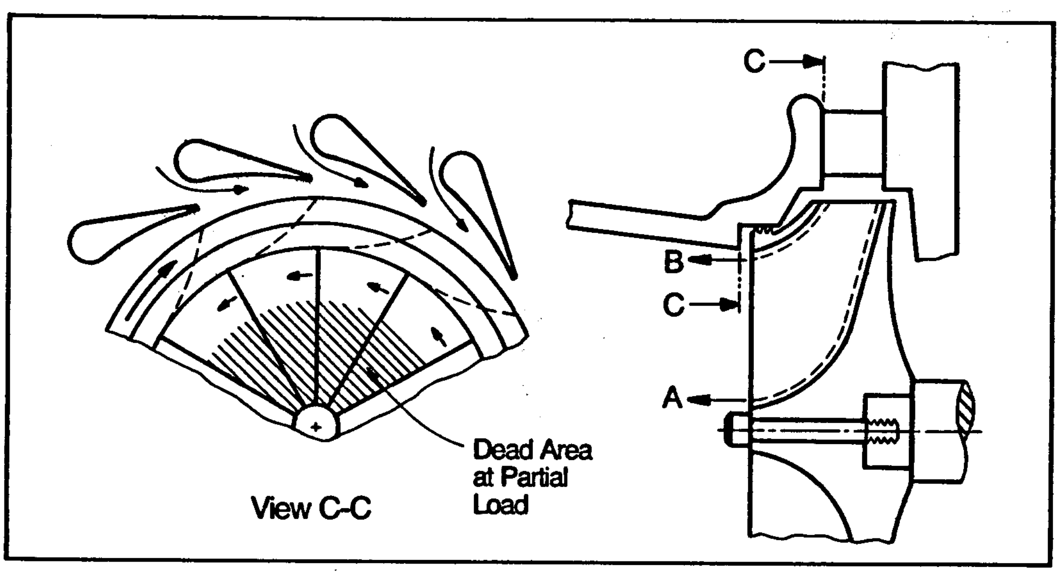
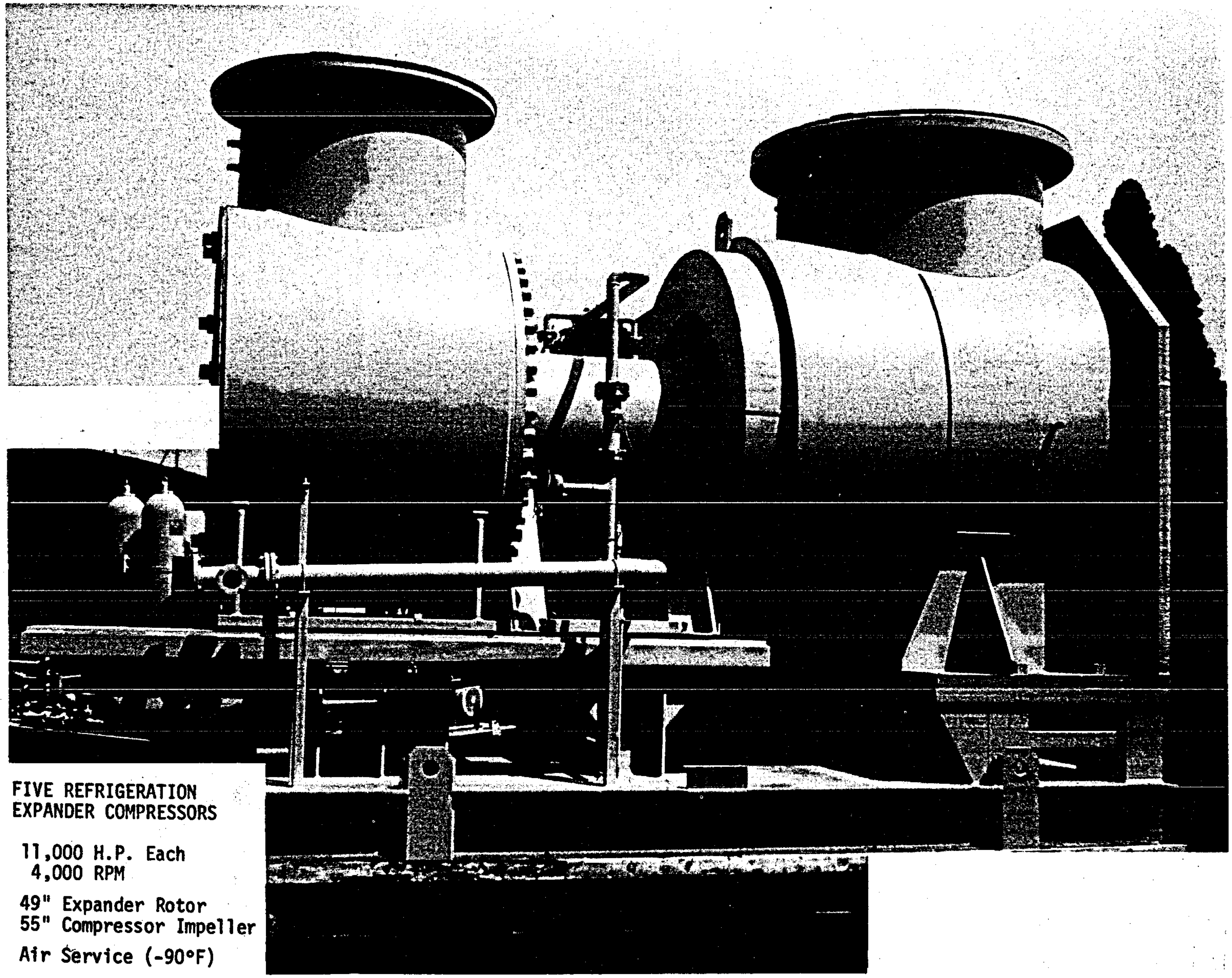

C
B
C
A
Dead Area
at Partial
Load
View C-C

FIG 3

FIG 4



FIVE REFRIGERATION
EXPANDER COMPRESSORS

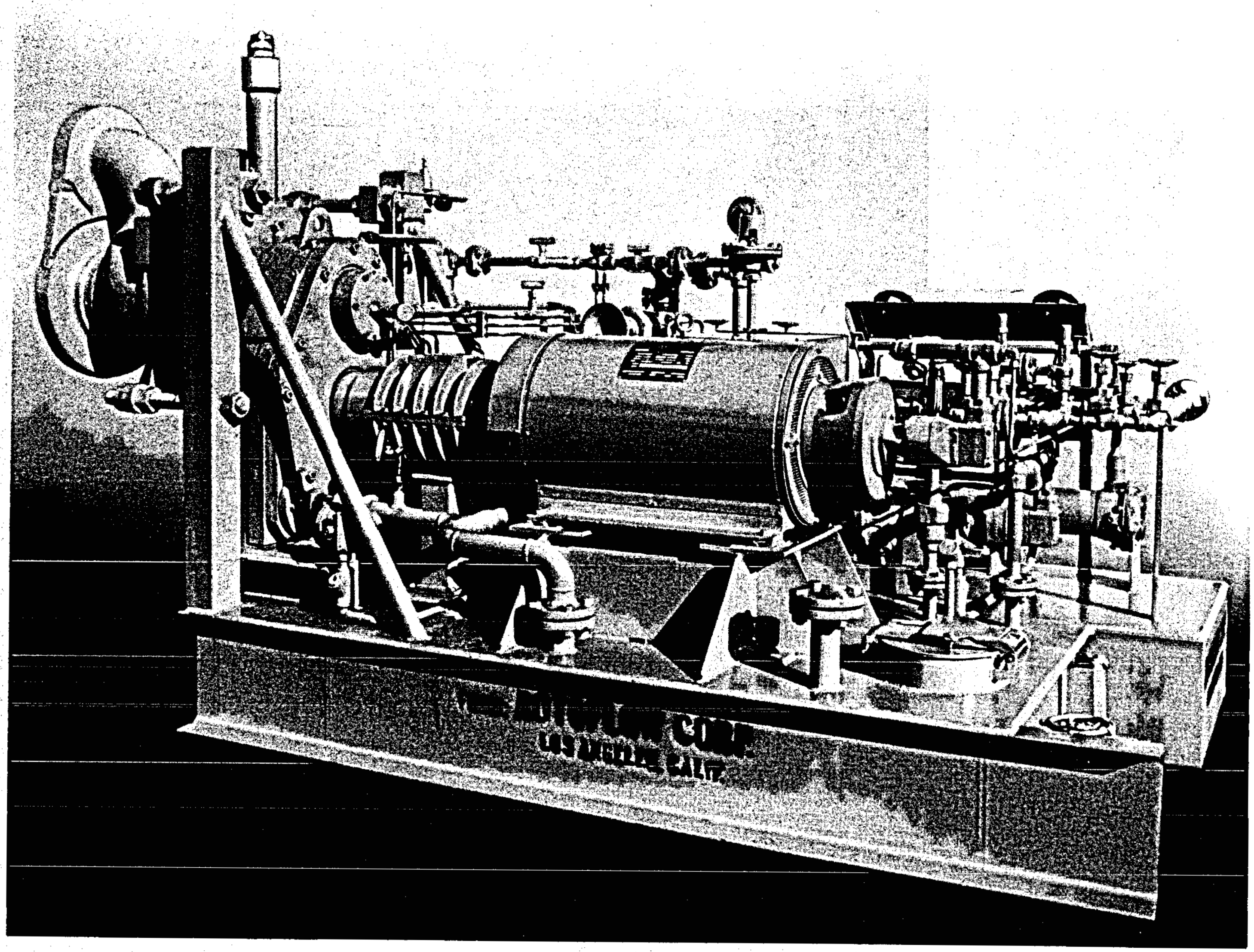
11,000 H.P. Each
4,000 RPM

49" Expander Rotor
55" Compressor Impeller

Air Service (-90°F)

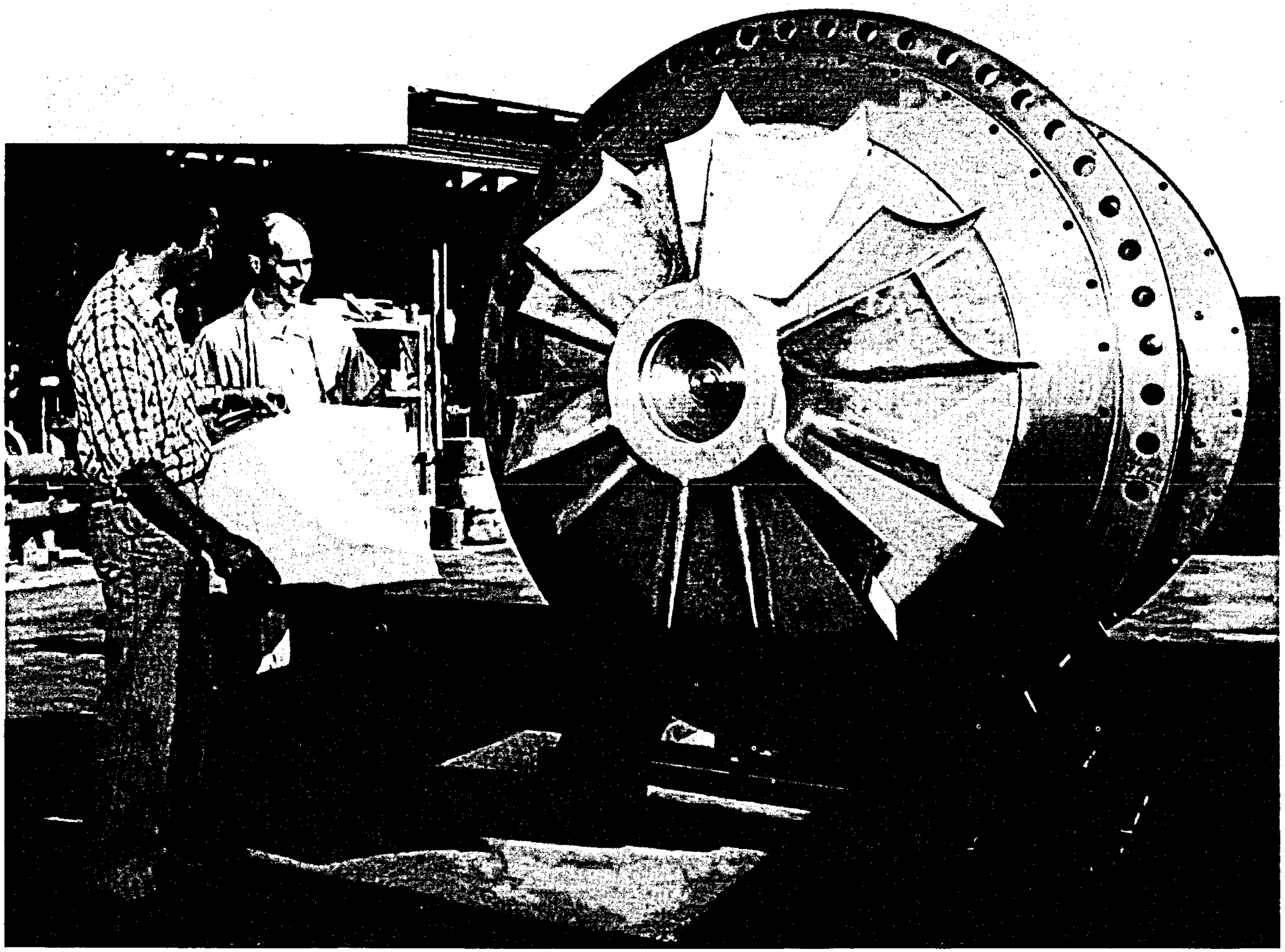
FIG 5.

FIG 6



Back view of Rotoflow machine for OTEC system, showing generator.

FIG 7



Mechanical center section of Rotoflow refrigeration turbine system can be removed intact from main unit. Compressor impeller above has 55-inch diameter.

GEOTHERMAL STEAM SEPARATOR EVALUATION

RP 1672-1

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Introduction The current technology for handling geothermal fluids has been developed to meet the specific needs of operating geothermal installations at locations such as Lardarello, Italy; the Geysers, California; Wairakei, New Zealand; Cerro Prieto, Mexico; and various locations in Iceland and Japan. The geothermal fluids at each location--vapor or liquid dominated--present unique problems in terms of mineral content, moisture content, operating temperature and pressure, and other properties.

These fluids contain many types of dissolved minerals in a wide range of concentrations. There is a need to develop criteria for the optimum selection of steam separation equipment that will meet the requirements imposed by the fluid characteristics in these fields.

The carryover of brine droplets with separated steam can hinder system performance and increase capital and maintenance costs.

Bechtel undertook a study of geothermal fluid process technology to help establish criteria for the selection and/or design of steam separators. The specific objective of this study is to establish the performance requirements for steam separators in a geothermal environment and analyze the applicability of current technology for separator apparatus. The result of this analysis is used to select four candidate separators, three of which will be the subject of a detailed analysis and field testing during the project.

Geothermal Steam Contamination Problems The project deals with geothermal steam extracted from hydrothermal resources. Hydrothermal resources can be subdivided into either liquid or vapor dominated resources depending upon the amount of steam present. In either case, the steam is used to generate electrical power either directly in a steam turbine or indirectly in a binary process.

This steam can be contaminated from the following sources:

- Moisture carryover
- Carryover of dissolved solids from the liquid phase (steam purity)
- Vaporization of partially volatile solid materials
- Entrainment of suspended solids, such as sand and mud

This study considers the first three contaminants. The removal of suspended solids is solved by other equipment than that used for moisture and phase separation. The problems of non-condensible gases such as carbon dioxide and hydrogen sulfide were not included within the scope of this project.

In a typical geothermal power production facility, fluid from a geothermal well enters a steam separator. This is the primary separator whose function is to separate steam from a steam-water mixture. The brine then enters a flasher. This is a secondary steam generator which creates a two phase mixture from the brine and separates out the steam.

In both cases, the steam generated contains the contaminants of interest--moisture, dissolved solids, and volatile solids. This steam is characterized by its quality and purity.

Quality is defined as the fraction by mass of vapor in a mixture of liquid and vapor. It is expressed as a percentage so that 100% quality is a saturated vapor (0% moisture) and 0% is a saturated liquid (100% moisture). A saturated vapor is also known as dry steam.

Purity is the insoluble matter (residue) found upon evaporation of a sample of the condensed steam. It is expressed as parts per million, ppm, by weight.

Excessive moisture and dissolved ions can lead to problems with mechanical components (particularly the steam turbine but also downstream components such as the condenser) and affect the plant performance. These problems arise from the following effects:

1) Corrosion results from chemicals carried over with the steam.
2) Erosion of turbine surfaces results from water droplets.
3) Depositon can cause either turbine problems by deposits of solids which reduce the pas-

sage area with resultant loss in efficiency and capacity. It can also lead to problems with other equipment. For example, there can be a significant loss in the heat transfer rate in the condenser.

4. Moisture in the steam leads to a loss of turbine efficiency. It is estimated there is about a three-quarter percent loss in turbine efficiency for every percent moisture in the steam to the turbine.

One of the most troublesome chemical elements for a steam turbine is silica. This can be carried over either as a dissolved solid or in a volatile form. Conventional steam turbines set limits of silica in the steam of 0.01 to 0.02 ppm and at this level, no silica deposition occurs. Thus, many years of operation can be expected without turbine maintenance. Two years or less appears to be common as an operational time for a geothermal steam turbine. However, a case is reported for which the geothermal steam turbine has operated over 15 years without silica depositon. In addition to maintainance problems, there can be a loss of turbine output which can represent a very significant cost. For an assumed case, based upon Cerro Prieto experience, the cost is in excess of $2 million per year per 37.5 MW power plant.

Steam Separators A review was made of the types of steam separators most commonly used or under consideration for geothermal power plants. This was accomplished by a literature review and the submittal of a questionnaire to users, designers, and developers. The most commonly used separators are the bottom outlet cyclone (also known as BOC or Webre type), the impingement type, wire mesh, centrifugal/impingement, and scrubbers. Moisture and salinity removal efficiencies of 99.95 percent are reported for the BOC type. A summary of their performance is shown in Table 1. Of the separators listed, the highest removal efficiencies are for the wire mesh, impingement, and centrifugal/impingement types.

Test Program As part of this project, a field test unit is being built to determine the performance and efficiency of the selected separator types under geothermal operating conditions. The design conditions for a 50MW geothermal power plant have been used to establish the desired operating conditions. Testing is expected to begin near the end of 1981.

Two 50 MW plant design cases were examined to establish design conditions under which steam separators must work. The first case is representative of a high salinity, high temperature brine as found near the Niland area of Southern California. The second case is representative of moderate temperature, low-to-intermediate salinity geothermal fluids, as found in the areas near Heber and Ease Mesa in Southern California.

The test unit will be able to test for these brines the following devices:

- Bottom outlet cyclone
- Impingement type separator (in conjunction with the BOC)
- Mesh type separator (in conjunction with the BOC)

The BOC produces an adequate steam purity by itself for many locations. However, when combined with either the impingement or the mesh type separator, improved purity can be expected.

Conclusions The following conclusions are made:

1) Moisture and salinity in the steam can cause significant problems, especially for the turbine. This results in a substantial increase in cost due to downtime and reduced plant output.
2) One of the most troublesome chemical elements is silica as it causes depositions on the turbine blades. Other elements affect turbine material selection due to their corrosive properties.
3) Adequate steam purification can decrease the

Table 1 **STEAM SEPARATOR COMPARISON CHART**

TYPE \ CHARACTERISTIC	APPLICATION	PRESSURE DROP
B.O.C.	PP	HIGH
WIRE MESH	MR	LOW
IMPINGEMENT	MR	LOW
CENTRIFUGAL/ IMPINGEMENT	MR	MED
SCRUBBERS	MR, PI	MED

Application: PP--Primary Phase
MR--Moisture Removal
PI--Purity Improvement

Pressure Drop: Low--<5 in H_2O
Med--5 in H_2O to 5 psi
High-->5 psi

silica level to the turbine so that no deposits will occur. Silica levels of 0.02 ppm in the steam are required. Steam purification methods by other than mechanical means may be required to reach this level.

4) The amount of steam purification required depends upon the plant operating conditions (pressure and pH) and salinity content of the geothermal brine.

5) Although the bottom outlet cyclone separator appears to do an adequate job of moisture removal and purity improvement, further improvements in performance can be obtained by the use of other moisture removal devices. This may significantly increase the plant efficiency and performance, and decrease the cost of operation.

GEOTHERMAL SCALE CONTROL BY CRYSTALLIZATION

RP-1525-2

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Introduction The deposition of scale in a geothermal power plant is considered a major risk. Unless scaling can be reduced to an acceptable level by an on-line treatment technique, the geothermal plant must be designed with redundant trains to permit the shutdown and off-line cleaning of a portion of the plant while the balance of the plant continues to operate. This approach not only increases capital investment but involves a substantial expenditure for the chemicals and labor required for descaling. This paper reports the development of a crystallization technique to minimize scale formation in a geothermal power plant without the use of acid or scale inhibitors.

Problems Resulting from Scales The seriousness of scale deposition has been amply demonstrated in plants which manufacture industrial chemicals as well as in geothermal plants. The continued deposition of scale leads to obstruction of process equipment, the blockage of pipe lines, and the "freezing" of valves and pump shafts. A layer of scale on metal surfaces occludes stagnant pockets of liquid, causing locallized pitting attack. Several examples are cited here.

Bechtel was directly involved in tests on a large flashed-steam geothermal pilot plant fed with very saline geothermal brine in the Salton Sea area of Southern California. A thin layer of silica/sulfide scale caused serious pitting corrosion in the carbon steel feed line to the plant. Silica scale, which had deposited in some process vessels to a depth of almost two feet, required hand cleaning and hydroblasting for its removal. Scale deposited so rapidly on thermowells and pressure gauge taps as to make the readings meaningless. Valves froze. Pump shafts required replacement every two months. Initially, an injection well was clogged by scale.

As a second example, at a 3-plant geothermal desalination installation at East Mesa, calcium carbonate scale reduced the flow passage in a 10-inch pipe to an opening four inches in diameter after only four months' operation. A barium sulfate deposit reduced the heat transfer of tubing to only a fraction of its initial value.

Techniques of Scale Control Although the list of failures enumerated above appears to be discouraging, there are methods for dealing with at least some of the problems. In this section are discussed Bechtel experiences and the experience of others in scale control:

- Redundancy, while not a scale control technique, provides the plant designer with one alternative in dealing with this problem. As an example, the plant can be designed with three trains, each of 50% of the total plant capacity. The rated output is delivered by two of the trains while the third is shut down for cleaning. Redundancy involves a substantial increase in plant investment. In addition, there is the added cost for the labor and materials required for descaling. The three-train concept contains the tacit assumption that the cleaning of one train can be accomplished before a second train must be shut down. If this assumption is not valid, it may be necessary to provide four or more trains.

- The operation of several geothermal pilot plants presented the opportunity to test another alternative scale control technique. At the East Mesa Test Site of the U.S. Department of the Interior, several additives were tested in three geothermal desalination plants.

The most successful was a compound marketed under the name of Dearborn #8010, which was effective in controlling scaling by calcium carbonate, calcium sulfate, barium sulfate, and strontium sulfate.

In the Niland area of the Imperial Valley of Southern California, on the other hand, the brine chemistry is entirely different. Of all the scale control additives tested there, only one showed any promise against silica and heavy metal sulfides, the principal offenders, and that inhibitor deteriorated rapidly at the elevated brine temperatures.

- An interesting alternative was developed for the control of silica scaling. It was discovered that when the brine became supersaturated in silica as a result of a drop in temperature, the SiO_2 formed submicroscopic micelles. These micelles could be prevented from agglomerating for long periods of time by maintaining the brine at a low pH. For example, a pH value of 3.0 to 3.5 retarded scaling for periods as long as two hours, a sufficient length of time to permit reinjection and migration of the brine into the subterranean formation. To avoid excessive corrosion at such low pH values, however, it would have been necessary to construct, or at least to line the plant and reject brine lines with the more costly corrosion-resistant alloys. Consequently, in spite of the promising laboratory results, brine acidification was not considered for the 10 MWe geothermal power plant operated by the San Diego & Gas Electric Co., where the Niland brine's scaling tendencies severely hampered the functioning of the plant.

- In that plant, the reject brine was stabilized by contact with a slurry of suspended scale in a reactor-clarifier which followed the flash chambers, thus protecting the injection well and the surrounding geologic formation. In addition, tests were begun on slurry seeding for scale control upstream in the geothermal flashed steam plant so as to protect the plant equipment and lines from scale.

Of all the alternatives for controlling the scaling of high silica brines, slurry seeding appears to have the best potential. The use of slurry seeding is an old, established process. It has been applied for many years to to the crystallization of salt, fertilizers, and industrial chemicals. In these processes, while concentrating an aqueous solution of the desired materials, undesirable impurities (for example, calcium sulfate) precipitate from the liquor. The precipitated scale particles circulate with the liquor. As additional scale is formed, it deposits on the suspended particles in preference to the walls of the vessels and piping. As a result, the equipment remains clean and free from scale deposits. Improved scale control is achieved by augmenting the self-generated scale particles by addition either of synthetic "seeds" or by a slurry of scale removed from a preceding batch of brine.

This procedure was extended in the early 60's to the desalination of sea water in pilot plant tests at the Office of Saline Water Test Site at Wrightsville Beach, N.C. These tests were directed toward the prevention of calcium carbonate scaling in a vertical tube evaporator without dosing the sea water with acid or a threshold inhibitor. In acid dosed plants in general use at that time, acid accelerated the corrosion of vessels, lines, and heat exchange surfaces. The inhibitors which were then available were ineffective under the conditions prevailing in the evaporator. It was hoped that slurry seeding would successfully replace these older methods of scale control. The equipment was charged with a quantity of "Snow White Filter", a commercial grade of calcium sulfate anhydride. After several hundred hours of operation, the plant was opened and found to be virtually scale free.

Basis of Crystallizer Process In the process described here, a seed slurry is maintained in suspension in each of the two stages, which deliver flashed steam to the high-pressure and intermediate pressure ports, respectively, of the steam turbine. The turbine, in turn, drives a generator. Each stage in the flowsheet of Figure 1 consists of a flasher-crystallizer-separator (FCS). The following steps occur in the FCS:

- As the brine enters each vessel, a fraction of its water content is flashed into steam, which is delivered to the power plant turbine.

- The evolution of steam fron the brine increases the concentration of all dissolved species in the residual liquor, including the scale formers.

- Gases such as carbon dioxide, ammonia, and hydrogen sulfide are released, causing changes in pH and brine chemistry.

- A drop in temperature accompanies the flashing process, resulting in the supersaturation of some of the dissolved species which have a positive temperature coefficient of solubility.

In an attempt to relieve supersaturation, numerous crystal nuclei are rapidly formed unless the flashing zone already contains an adequate population of nuclei. In the latter case, the pre-existing nuclei grow to a size favorable to the subsequent sedimentation and filtration steps. Absence of such nuclei, on the other hand, leads to the formation of many new crystals. The distribution of the precipitating species among this large population results in very small crystals, which are difficult to remove by settling or filtration.

Flasher-crystallizer-separator (FCS) Design

In the design developed under this study, the spontaneous formation of many small nuclei is prevented by contacting the flashing brine promptly with seed crystals of scale which had been generated previously. In the conceptual design shown in Figure 2, geothermal brine is introduced into the bottom of the FCS. The jet of brine entering the throat of the venturi entrains a slurry of previously formed scale. The pressure drop in the throat flashes a portion of the hot fluid into steam. The high vapor-to-liquid ratio in the ascending three-phase fluid results in a very low fluid density.

When the ascending fluid strikes the baffle plate, steam separates while the remaining slurry is deflected downward around the outside of the venturi. The descending slurry is drawn into the bottom of the venturi to repeat its circuit. The self-induced agitation replaces the mechanical turbine-blade stirrers commonly installed in crystallizers, eliminating the attendant equipment cost, power consumption, maintenance problems, and attrition of the crystals (Ref. 1).

Those crystals which have grown to maximum size settle to the bottom of the FCS and are drawn off through the sludge discharge line. A small stream of brine ascends the sludge pipe so as to elutriate the fine particles and recycle them to the recirculating sludge circuit for further crystal growth.

After flashing, the brine rises through the sludge blanket in an annular separator region surrounding the central slurry recycle zone. The added contact with crystals of the sludge blanket helps to stabilize the brine against post-precipitation. The brine rise rate in the separator zone is calculated to achieve the required clarity.

The brine, once its supersaturation is relieved, can move through the remainder of the plant and the injection system without danger of harmful scale deposition. A fraction of the slurry is recycled externally back to each flasher-crystallizer. Those crystals which have grown sufficiently large to permit ready separation are removed and either discarded to waste or delivered to a mineral recovery sub-system. The "seeds" in the slurry may be either self-generated or may be added to the brine from an external source.

Design Guidelines As a practical alternative to pilot plant data, which are not available at present, the designer can rely on scaling experience in geothermal operation supplemented by analogous industrial crystallization experience. For the growth of seed crystals, it had been observed that the growth rate of scale on the lines bringing Magmamax #1 brine from the wellhead to the San Diego Gas & Electric Co.'s geothermal pilot plant was 0.1 mils per hour or 0.0000423 mm. per minute (Ref. 2). If we assume all slurry seeds to be of 10 micron diameter, for example, Table 1 shows that precipitation at 0.1 mils per hour would require a retention time of only 6.6 seconds in the slurry recycle zone of the first crystallizer to relieve supersaturation. Even very large seeds of 300 microns diameter, such as 48 mesh sand, require only about 3 minutes to relieve supersaturation in Stage 1.

Reference 2 shows a scaling rate of roughly 1 mil per hour for the conditions anticipated in the second crystallizer in the present report. This calculates to a required retention time of less than one minute in the slurry recycle zone of the second crystallizer even for the comparatively large sand nuclei.

Weres (Ref. 3) reports tests on the growth of micelles of amorphous silica in which the growth rate is more than an order of magnitude slower than the growth of scale observed on the pilot plant walls and piping. Extensive research on crystal growth, however, has demonstrateda very slow or even zero growth rate on extremely small nuclei.

Another source of uncertainly stems from the fact that the seed crystals will not all be of the same diameter but, instead, will represent a wide (possibly Gaussian) size distribution. R. Bennett provided details concerning industrial experience involving the growth rate of crystals under a variety of conditions (Ref. 4). The crystallizer concept was tested by Imperial Magma on geothermal brines in the Salton Sea area, demonstrating that a flash-crystallizer which circulates a 1% crystal slurry is capable of preventing scale deposition on the plant equipment by brine supersaturated with silica (Reference 5). The results of field and laboratory tests were correlated by Dr. A. Randolph and a correlation of crystal growth rates developed to serve as a basis for the design of the FCS (Ref. 6).

In order to attain a reasonably close approach to equilibrium, the operating conditions shown in Table 2 apply a generous factor of safety to the plant scaling rates of Reference 2. The guidelines of Table 2 form the basis for the material balance in the flowsheet of Figure 1 and the dimensions of the second stage FCS in Figure 2.

The brine effluent from the second stage FCS passes through a dual media gravity filter prior to reinjection. The target purity of the second stage effluent was selected to minimize the frequency of backwashing of the gravity filter.

In contrast to stage #2, the effluent from stage #1 is permitted to contain a much greater load of suspended solids, which will merely combine with the stage #2 slurry crystals in the crystal-growth zone. Consequently, the brine rise rate in the outer annulus may be much greater. This permits the designer to provide a vessel of smaller diameter for stage #1, as shown in Figure 3. Since stage #1 must withstand a working pressure of 1,006 kPa, a decrease in vessel diameter represents a substantial cost reduction.

Conclusion On the basis of the study reported here, a significant reduction in the cost of generating power from a hydrothermal resource may be anticipated. The cost reduction results from the elimination of the redundant train(s) required to permit off-line cleaning of one or more trains, together with the additional piping, valves, and instruments associated with redundancy. A further reduction in plant investment stems from the elimination of the three 55-foot diameter reactor clarifiers required to protect the injection pump and well of a 50 MWe geothermal power plant, an investment of roughly $2,300,000. From the standpoint of operating costs, the cleaning of a redundant train requires the full-time service of a cleaning crew throughout the year. This cost will be eliminated by the FCS design. Finally, the fractionation of low-temperature from high-temperature scale by the dual FCS design may segregate the mineral content of the brine, converting at least a portion of the sludge from a costly disposal problem to a salable material.

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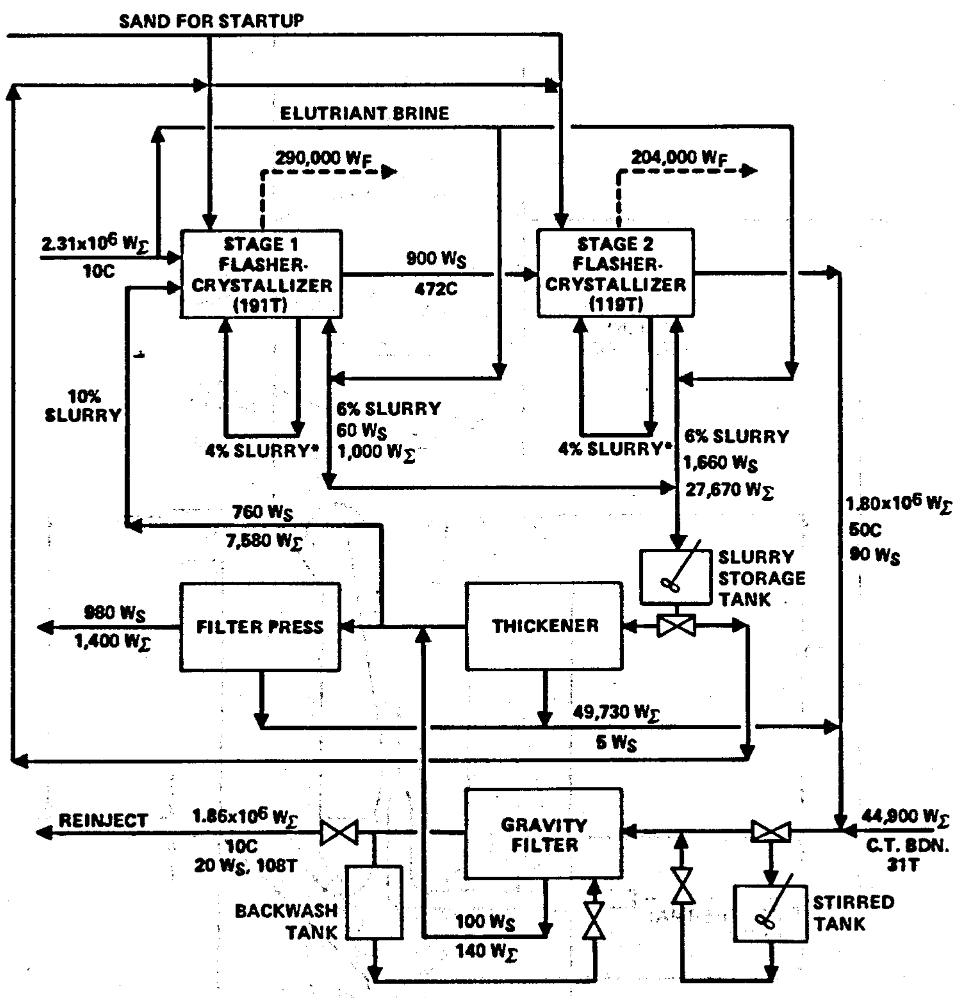


NOTES:

- W = FLOW, IN KG/HR, OF BRINE
- W_S = FLOW OF SOLIDS (SUSPENDED)
- W_Σ = FLOW OF SOLIDS + BRINE
- C = CONCENTRATION IN PPM BY WEIGHT
- W_F = FLOW OF FLASHED STEAM
- T = TEMPERATURE IN °C
- * = INTERNAL CIRCULATION
- --- = VAPOR FLOW

Figure 1 MATERIAL BALANCE: FLASHER-CRYSTALLIZER-SEPARATOR SECTION

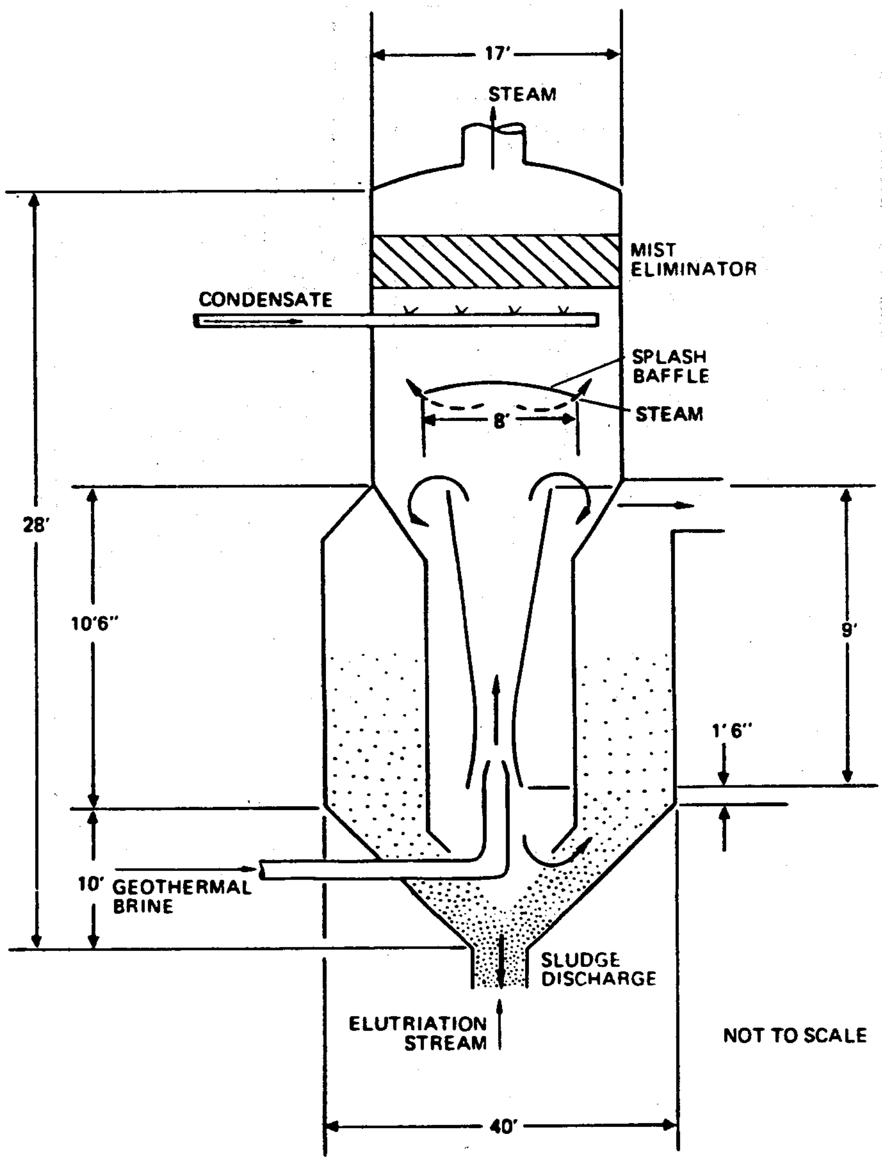


Figure 2 STAGE 2 FLASHER-CRYSTALLIZER-SEPARATOR

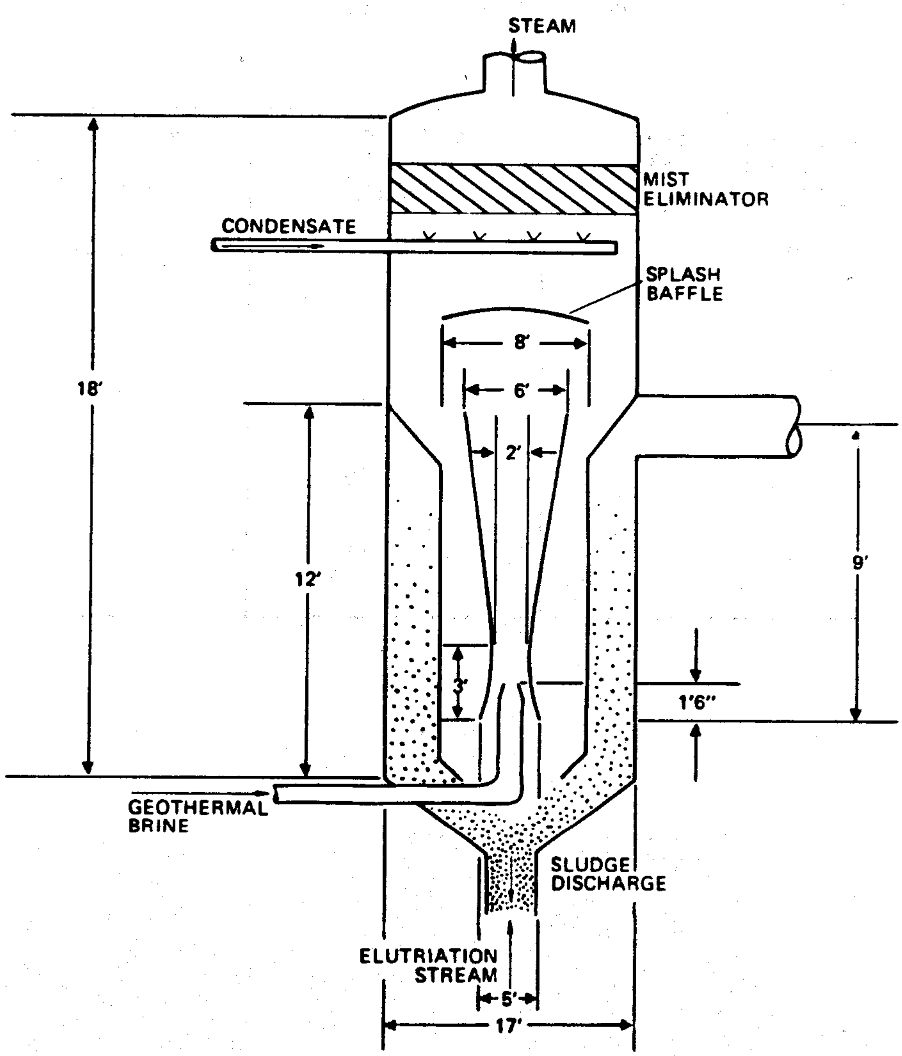


Figure 3 STAGE 1 FLASHER-CRYSTALLIZER-SEPARATOR TEST UNIT

Table 1

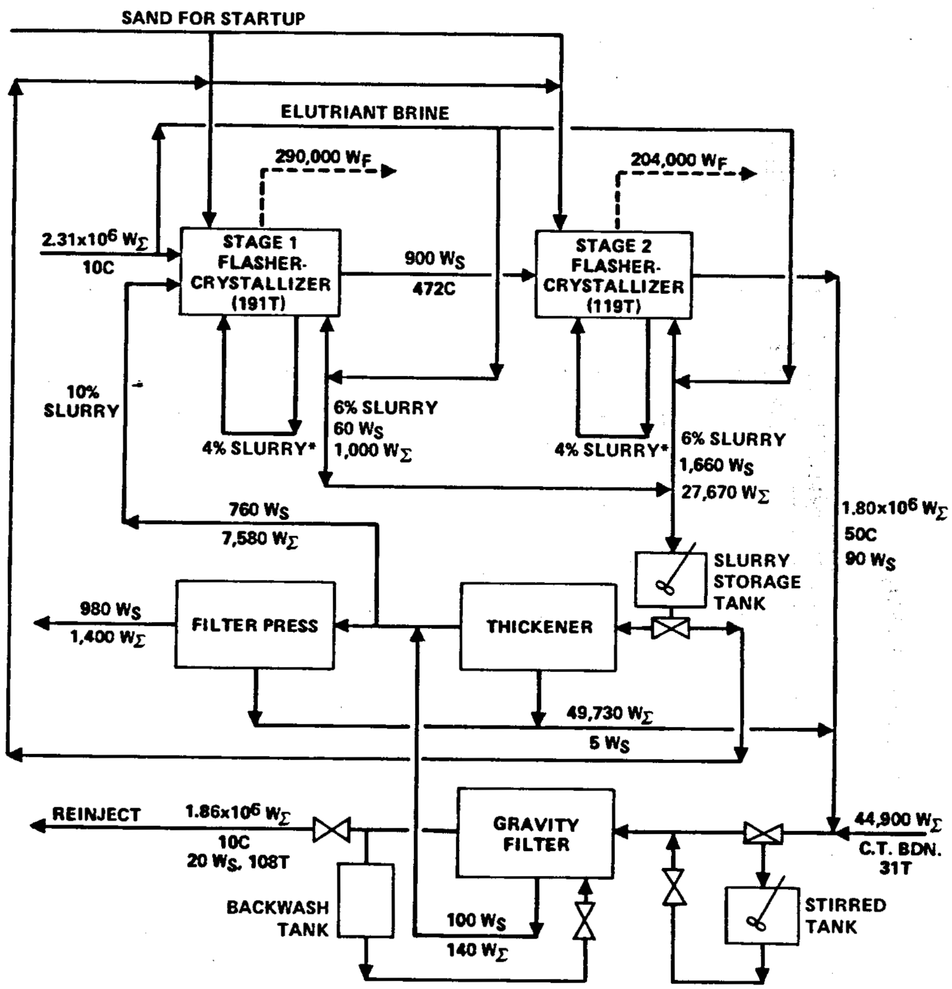
RESIDENCE OF CRYSTALS REQUIRED
TO RELIEVE SUPERSATURATION

Initial Diameter of seed particle (microns)	Residence Time required (minutes)	
	Stage 1	Stage 2
10	0.11	0.02
20	0.21	0.03
50	0.53	0.09
75	0.79	0.13
300	3.17	0.53

Table 2

GUIDELINES FOR CRYSTALLIZER DESIGN

	Flasher-Crystallizers		
	Stage 1	Stage 2	General
Number of trains	-----	-----	1
Mean seed crystal size (microns)	-----	-----	300
Brine feed to vessel (kg/hr)	2.31×10^6	2.02×10^6	-----
Brine leaving vessel (kg/hr)	2.02×10^6	1.82×10^6	-----
TDS in leaving brine (ppm)	257,000	286,000	-----
Internal recycle slurry concentration (wt. %)	-----	-----	4.0
Brine residence time (minutes)	3.0	21.0	-----
Slurry crystal residence time (minutes)	45	27	-----
Brine rise rate in the separating zone			
(gpm/sq. ft.)	48	5.8	-----
(cm/sec.)	3.3	0.4	-----
Flashed steam - Pressure (kPa)	1,006	145	-----
Temperature (^oC)	191.1	119.4	-----
Velocity during droplet disengaging (cm/sec.)	58	244	-----



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--- = VAPOR FLOW

Figure 1 MATERIAL BALANCE: FLASHER-CRYSTALLIZER-SEPARATOR SECTION

FIELD TEST UNIT TO DEVELOP SCALE CONTROL TECHNIQUES
FOR BINARY CYCLE POWER PLANT

RP-1525-1

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The objective of this project is to evaluate alternative methods of controlling scale that can form on the brine side of heat exchangers used in a binary power systems.

On June 9, 1981 we completed a 30-day scaling test on a geothermal well. At present, we are correlating data from this test in order to determine exactly what was occurring during the test.

In order to evaluate scale control methods a test unit comprised of two parallel sets of steam separators and heat exchangers was constructed. The design of these exchangers duplicates the flow path of the exchangers which are being designed for a proposed 10 MW binary power plant. Each set of exchangers has 36' long passes. The first four passes are sized to condense vapor coming from the top of the steam separator and the last six passes are sized to cool the condensed vapor and brine as rejected to the separator. Heat from the condensed vapor and brine is rejected to the atmosphere through a circulating oil system and an air cooled heat exchanger. The two parallel sets of exchangers can be operated individually so that comparative testing can be carried out, thus saving valuable time and allowing us to directly observe comparative results of different scale inhibiting treatments.

The test plan envisioned that we would be able to monitor heat transfer rates and fluid flow through the exchangers. By opening the ends of the tube bundles we would be able to make a visual assessment of scaling conditions at the ends of the tubes and in the passages between the bundles. Temperature, pressure, and flow measurements were recorded hourly for all the instruments mounted on the unit. Seventeen temperature measuring points were also recorded by a strip chart recorder. Differential pressures were measured and recorded on strip charts for the flow measuring devices.

Test experience indicates that a number of minor improvements should be made to the test unit prior to proceeding with further field testing. The changes envisioned would reduce the manpower required for running the test, provide more accurate measurements and provide additional sample points.

The design of the exchange heads needs to be modified in order to provide easy access to the tube ends and provide better placement of gas vents, sampling points, cross-over pipes, thermometers, thermocouples, etc. This will greatly reduce the time required for inspection, cleaning and turn around of the unit when it is being serviced. The readings we observed on some thermocouples and thermometers lead us to believe that they were not indicating the true temperature of the stream they were supposed to be measuring. Careful repositioning of the temperature measuring points will no doubt improve the accuracy of our heat transfer measurements.

Accurate fluid flow measurements in the oil circulating loops are difficult to obtain when simple orifice plates are used as the measuring element due to the viscosity changes which occur as the oil temperatures change. We expect that with improved instrumentation, accurate fluid flow measurements will not be a problem.

Fluid flow measurements on the brine side of the exchanger were made using a head tank ahead of an orifice. We were able to calibrate these orifices during operation and we feel that they are relatively accurate.

We plan to connect temperature, flow, and pressure sensing elements to a data logger in order to record most of the test data automatically. This will reduce our manning requirements on future tests to a minimum and provide data in a convenient form. During the first test we ran heat balances at the site using a printing calculator.

Presently, we are correlating data gathered during the test and awaiting results of laboratory analysis so we can arrive at some conclusions about the scale formations which occurred.

In brief, we did experience some scaling during the 30-day test run when we ran untreated geothermal fluid through one set of heat exchangers. The second set of heat exchangers operating with Nalco 7274 (neutralizer/Hydrazinc) in the steam condensing section and Nalco 780 (sulfite) plus Nalco 7317 (scale inhibitor) in the liquid section of the heat exchanger did not scale up as rapidly. We were able to clean the exchangers, using a caustic solution + a 10% acid wash followed by a 1% caustic wash to neutralize the acid within the exchangers. Due to a number of factors we were not able to follow through on our test with corresponding chemical treatment corrections due to the time lag between our obtaining scale samples and getting laboratory reports back so as to take effective corrective action.

PRELIMINARY EVALUATION OF THE COPPER SULFATE PROCESS FOR REMOVAL OF HYDROGEN SULFIDE OVER A RANGE OF GEOTHERMAL STEAM CONDITIONS

RESEARCH PROJECT No. RP1197-3

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Background. EIC Laboratories' CUPROSUL Process, which uses an acidic solution of copper sulfate buffered with ammonium sulfate to remove hydrogen sulfide, ammonia, and other contaminants from geothermal steam, has been under development for six years. With support from DOE and PG&E, a large body of data for steam near The Geysers average composition and condition has been obtained in tests ranging from laboratory scale, in which about 100 pounds per hour of steam were treated, to prepilot scale field testing of 1000 pounds per hour, through the operation of an integrated pilot plant which treated 100,000 pounds per hour. Based on the results of these tests, PG&E is proceeding with the design and construction of a commercial scale system at No. 7 Unit, The Geysers Power Plant, and EIC is currently completing the process design and specification package for a commercial scale system for the DWR Bottle Rock Project.

The process consists of four key steps:

- Scrubbing, in which the steam is desulfurized by contact with the copper sulfate solution upstream of the turbine. Solution compositions and contact times are controlled to obtain the required degree of abatement within limits of the allowable pressure drop, and the steam is then subjected to a series of disentraining/washing steps to remove residual entrainment to very low levels. The hydrogen sulfide is converted to solid copper sulfide precipitates, ammonia is removed as ammonium sulfate, and other contaminants are removed by dissolution in the scrub solutions.

- Liquid-solid separation, in which the sulfide precipitates are concentrated prior to regeneration and a clear liquid fraction is produced for further treatment. Sulfides formed in the scrubbing reaction at The Geysers average conditions settle rapidly by simple decantation and produce overflows of excellent clarity.

- Regeneration, in which the sulfide solids are converted to soluble copper sulfate for recycle to the scrubber by hydrothermal oxidation. Pilot plant tests at the 5 MW scale demonstrated that the solids could be oxidized quantitatively, using either compresssed air or vaporized oxygen, at a very rapid rate.

- Purge stream treatment, in which the excess soluble copper in the purged scrub solution is removed and recycled to the process, the decopperized stream is neutralized, and the effluent treated for by-product recovery or disposed of as appropriate.

Design criteria for the first three of these steps are very sensitive to the nature of the solids formed in the scrubbing step. We had found that the properties of solids produced in the laboratory under The Geysers average conditions - typically saturated steam with a pressure of about 9 bar, an H_2S content of 100-300 ppm, and an NH_3/H_2S ratio of at least one mole per mole - were essentially identical to those produced in field tests on "real" geothermal steam at a one thousandfold higher rate. Thus, the design criteria for the commercial plants are reasonably close to those originally proposed based on laboratory testing.

However, it is well known that the composition and condition of geothermal steams vary widely from resource to resource and may well be significantly different from The Geysers average. EPRI has provided support, through this study, to conduct a preliminary evaluation of the technical and economic viability of the CUPROSUL process over a range of geothermal steam conditions.

Results of This Study. A three-phase program was evolved to obtain the information necessary to carry out these technical and economic evaluations. The first phase involved a comprehensive literature search to define the extremes of conditions likely to be encountered in upstream scrubbing. By conditions, we mean both the chemical composition and the pressure and temperature or moisture content of the steam. We find little indication that resources or situations will exist which will result in turbine inlet pressures outside of the 6-11 bar range. This range is dictated by the economic balance between resource properties, fluid transportation costs, and equipment costs.

Very little reliable data have been published on the extent of superheat or moisture to be expected or the rate of at which steam compositions or conditions may change. The literature review did demonstrate, as shown in Figure 1, that steam composition is highly variable from resource to resource and within a given field. However, it appears that useful extrapolations can be made to somewhat higher and lower H_2S contents if a few points in the mid range are well defined at a given location. The ability to make such estimates is critical for situations in which the abatement system must be designed well before the steam field is developed. The compositions shown in Figure 1 also imply that very high abatement efficiencies, exceeding 99.5%, will be required to meet emission limitations which have been proposed at 100 g/MWh or less.

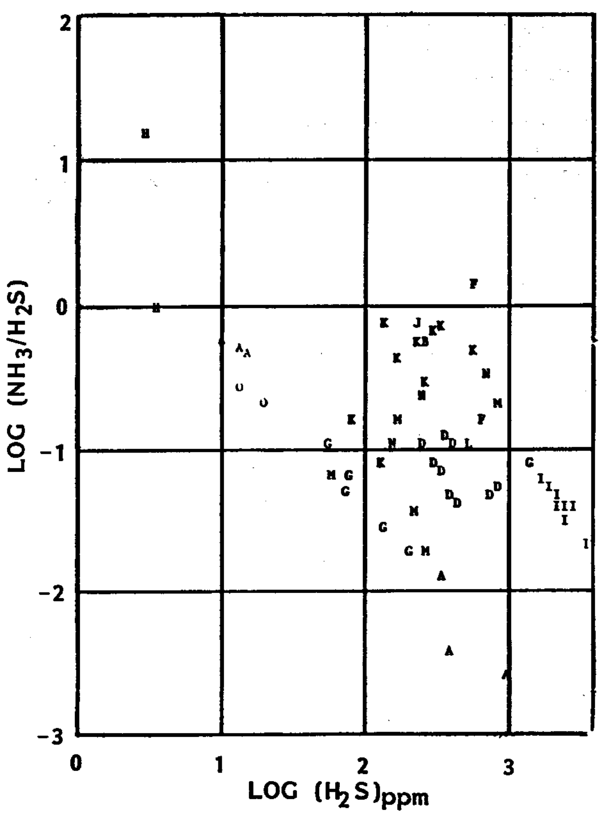

Figure 1. Steam NH_3/H_2S ratio as a function of H_2S content.

The second phase of the program consisted of a laboratory scale experimental investigation of the effects of process conditions on the chemistry and rate processes in the key steps. A series of six scrubbing and liquid/solid separation and five regeneration runs were carried out. Scrubber operating pressure ranged from 4.2 to 11 bar and scrub solution pHs were varied between 0.8 and 2.2, corresponding to a range of acidities which could occur in an integrated process which differed by a factor of 25. The scrub solution copper contents were varied between 0.6 and 4.3 g/ℓ and the vapor-liquid contact times, which were controlled by balancing steam and recirculating scrub solution flow rates, were varied from 0.1 to 1.7 sec. Equipment limitations prevented the attainment of longer contact times which were run in pilot tests at The Geysers. Evaluation of the scrubbing efficiency data, summarized in Table 1, required that the influence of contact time, solution composition, and scrubber operating temperature be rationalized. It was known, from tests at The Geysers conditions, that high pHs and copper contents promote good H_2S removal but that they cannot be increased without limit: at high pHs, NH_3 removal efficiency decreases and purge treatment costs increase directly with copper content. It was also known that the number of contact stages was approximately a factor of the square root of contact time as shown in Figure 2. These data show that contact times exceeding 2 sec are required to obtain very high abatement efficiencies and that the results of laboratory and pilot scale tests are consistent when normalized on this basis. The data also show that, at comparable solution compositions and contact times, scrubbing efficiency increases with increasing steam temperature.

All the solids produced in these tests showed comparable settling behavior, having short compression times and excellent overflow clarity. In general, solids produced from treating steam at lower pressures tended to settle at slightly lower rates and to lower pulp densities than those produced at higher pressure and temperatures. All the solids produced proved to be amenable to quantitative regeneration by pressure oxidation at relatively mild process conditions. However, in contrast to the settling behavior observed, solids produced at lower pressures could be regenerated more easily than those produced at high pressure. We believe that this behavior can be explained by the kinetics of the scrubbing reactions: solids precipitation and growth are more rapid at higher temperatures and the larger sized sulfide solids settle more rapidly but require a longer time to dissolve.

The third phase of the project consisted of a process evaluation and economic analysis to determine possible process configurations and costs at the extreme conditions. For purposes of this evaluation all components of the process were classified as having key design criteria, and therefore cost, primarily dependent on either steam flow rate or on the total amount of H_2S removed. Complete material and energy balances were then executed for all cases evaluated, preliminary design criteria applied to all major equipment items, and physical

TABLE 1. SUMMARY OF RESULTS, SCRUBBING TESTS

Run No.	314	328	404	411	416	524	The Geysers[d]
Pressure, Bar[a]	11.3	6.8	4.2	8.6	8.6	9.0	9.2
Steam Flow, kg/hr[a]	64	53	49	75	64	55	45,500
Inlet H_2S Content, ppm	245[a]	229[a]	206[a]	375,100, 45[e]	59,370, 540[e]	634[a]	230
Inlet NH_3 Content, ppm	0	0	0	0,45	71,0	0	170
Scrub Solution:							
g/ Cu	1.9-3	1.8-3.1	3.0-4.0	1.8-4.3	2.3-3.5	0.6-3.7	2.0
pH	0.9-1.4	0.9-1.3	0.8-1.3	0.8-1.2	1.8-2.2	1.0-1.2	1.2
Contact Time, sec[b]	0.5-1.2	0.25-0.9	0.1-0.7	0.1-0.4	0.15-0.7	0.5-1.7	1.8
Percent H_2S Removal	92.3-97.5	84-94.6	46-90	66-87	89-93.5	25-98.1	99
Percent S° Formation	1.6-3.9	1.2-2.6	3.1-8.1	5.1-19	4.6-18	0.1-1.1	10
Solids Composition, (n)[c]	1.21-1.71	1.87-1.96	1.42-1.56	1.87-1.94	1.74-1.87	1.70-1.80	1.9
Outlet NH_3 Content, ppm	8-149	1.5-13	1.2-14	2.0-33	21-88	3.8-14	17

[a] At average conditions.
[b] Froth height, or four times tray DP, divided by steam velocity.
[c] In solids of composition Cu_nS.
[d] For 5 MW demonstration plant.
[e] Varied throughout the run.

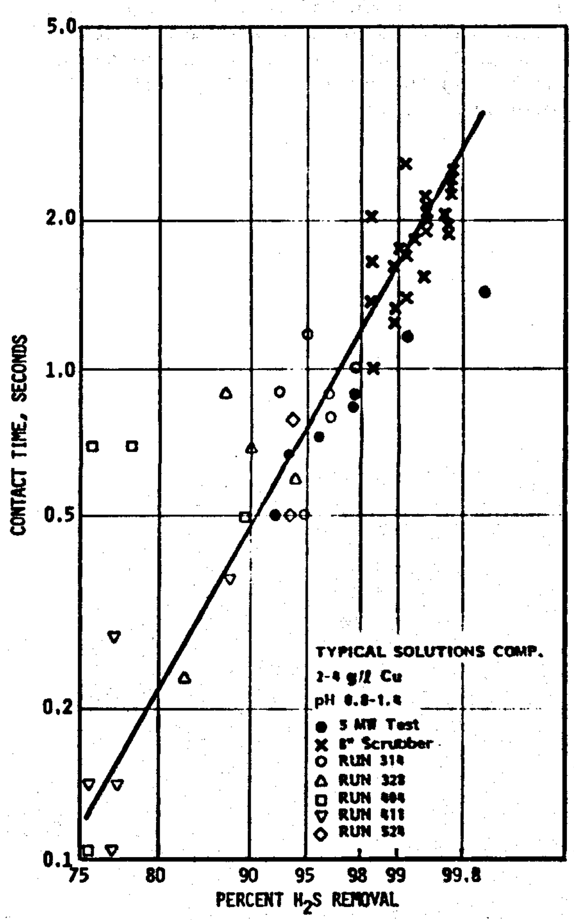

Figure 2. Effect of contact time on removal efficiency.

plant costs estimated by a factoring technique. Process configurations were found to be similar for all cases evaluated, except that regeneration by oxidation using compressed air was found to be of preferred option for steams containing lower H_2S concentrations.

The capital costs of the scrubber and its auxiliaries increase as steam pressure decreases because larger mass and volumetric flows of steam must be treated to obtain the same 55 MW of power. The capital costs of other plant sections increase as the amount of H_2S removed increases, and are somewhat sensitive to scrubbing pressure since scrub solution compositions and flow rates must be adjusted to maintain optimum abatement efficiency. Direct operating costs also increase as the amount of H_2S removed increases and as steam pressure decreases because of the larger flows of scrub solutions in circulation through the process. As shown in Table 2, operating costs are also sensitive to the amount of NH_3 present in the steam, particularly where the H_2S content exceeds about 500 ppm, since the cost of additional neutralizing agent required exceeds 50% of the total direct costs. For steam of The Geysers average composition, direct operating costs are approximately 1.4 mills/kwhr for a system capable of reducing emissions to a level of 50 g/MWh, corresponding to 97% H_2S abatement. Capital charges increase total operating costs to 4.4 mills/kwhr, and are the largest component of total costs for all cases evaluated.

Conclusions. While the chemistry of the scrubbing and regeneration steps in the CUPROSUL process is complex, laboratory tests have shown

TABLE 2. CAPITAL AND OPERATING COST ESTIMATE SUMMARY

Steam Condition		Capital Cost, $\$10^6$/hr			Total	Operating Cost, $\$10^6$/hr			Total
Pressure Bar	H_2S ppm	Plant Investment	Capital Charges	Total Capital	Capital \$/kw	Direct Cost	Fixed Charges	Total Operating	Operating mills/kwhr
11	2500	9.2	1.5	10.7	195	2.0	1.9	3.9	10.9
11	230	4.6	0.6	5.2	95	0.5	0.9	1.4	3.9
11	10	3.0	0.4	3.4	61	0.3	0.6	0.9	2.5
9	2500	10.8	1.7	12.5	227	2.2	2.3	4.5	12.4
9	230	5.4	0.7	6.1	111	0.5	1.1	1.6	4.4
9	10	3.4	0.4	3.8	69	0.3	0.7	1.0	2.8
4	2500	15.8	2.5	18.3	333	2.7	3.3	6.0	16.7
4	230	7.6	1.0	8.6	157	0.6	1.6	2.2	6.1
4	10	4.0	0.5	4.5	81	0.4	0.8	1.2	3.3

that high abatement efficiencies, rapid liquid solid separation, and rapid, quantitative regeneration of sulfide solids can be obtained at the extremes of process conditions likely to be encountered in upstream scrubbing. The laboratory data are consistent with results obtained from the operation of a 5 MW scale pilot plant at The Geysers, and were used to establish material and energy balances and preliminary design criteria for the operation of a system treating steam at higher and lower pressures, H_2S and NH_3 contents. These were used as the bases for developing factored capital and operating cost estimates to evaluate the viability of the process at the extremes of conditions evaluated.

Capital costs were found to increase with decreasing steam pressure and increasing H_2S content. Operating costs increase with increasing H_2S content and are dominated by capital charges. Direct operating costs are lower than the costs of peroxide required for supplemental condensate abatement of steams with high H_2S contents, and could be halved by modifying the process configuration to recover NH_3 for reuse.

MOBILE LABORATORY: RESULTS FROM THE FIRST YEAR

Contract No. RP 741-1

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The EPRI Mobile Geothermal Laboratory, designed and operated by the Energy Systems Group of Rockwell International, works toward three major project objectives; these are the generation of reliable analytical data for inclusion in the EPRI brine data base, the support with physical and chemical information of EPRI projects and utility field tests, and the establishment of standard procedures for physical and chemical measurements on geothermal systems. To meet these objectives, the laboratory was designed to have extensive capability for the analysis of geothermal brine, steam condensate, and non-condensible gases. A portable sampling unit, the fluid sampling system, is operated in conjunction with the mobile laboratory, and adds the capability to collect geothermal samples on site at an established geothermal facility or a test site. The laboratory, with the fluid sampling system, travels to the geothermal site and conducts sampling and analysis on site; this procedure gives maximum assurance of sample integrity and maximum flexibility in response to unusual occurrences in the field.

The laboratory has the capability to measure a large quantity of physical properties and chemical constituents of the geothermal fluid. Table 1 lists the important analytical and support equipment in the laboratory, and Table 2 lists the chemical species and physical properties which may be measured in the laboratory.

Because one of the objectives of the mobile geothermal laboratory is to generate a standard collection of physical and chemical data to characterize geothermal wells, a broad, inclusive characterization, called a signature test, has been designed. This test includes measurement on geothermal fluid of all of the properties and species measured by the laboratory; the results of a signature test become part of the EPRI data base package for that well and are readily compared to similar data for other geothermal wells.

Figure 1 is a diagram of the signature test and shows the methods of sample collection and analysis used. The fluid sampling system is capable of collecting samples in two ways; the temperature may be dropped and then the pressure (ΔT mode), or the pressure may be dropped and then the temperature (ΔP mode). For the collection of liquid samples for chemical analysis, the ΔT mode is used, and for the collection of gas samples and the evaluation of physical properties, the ΔP mode is used.

Any combination of measurements may be made in the laboratory in response to the requirements of a particular project. A tracking test comprises repetitive sampling and analysis at specified times of particular properties and species and is designed for a particular project and purpose. A special test is generally performed once and may measure any combination of properties and species

TABLE 2

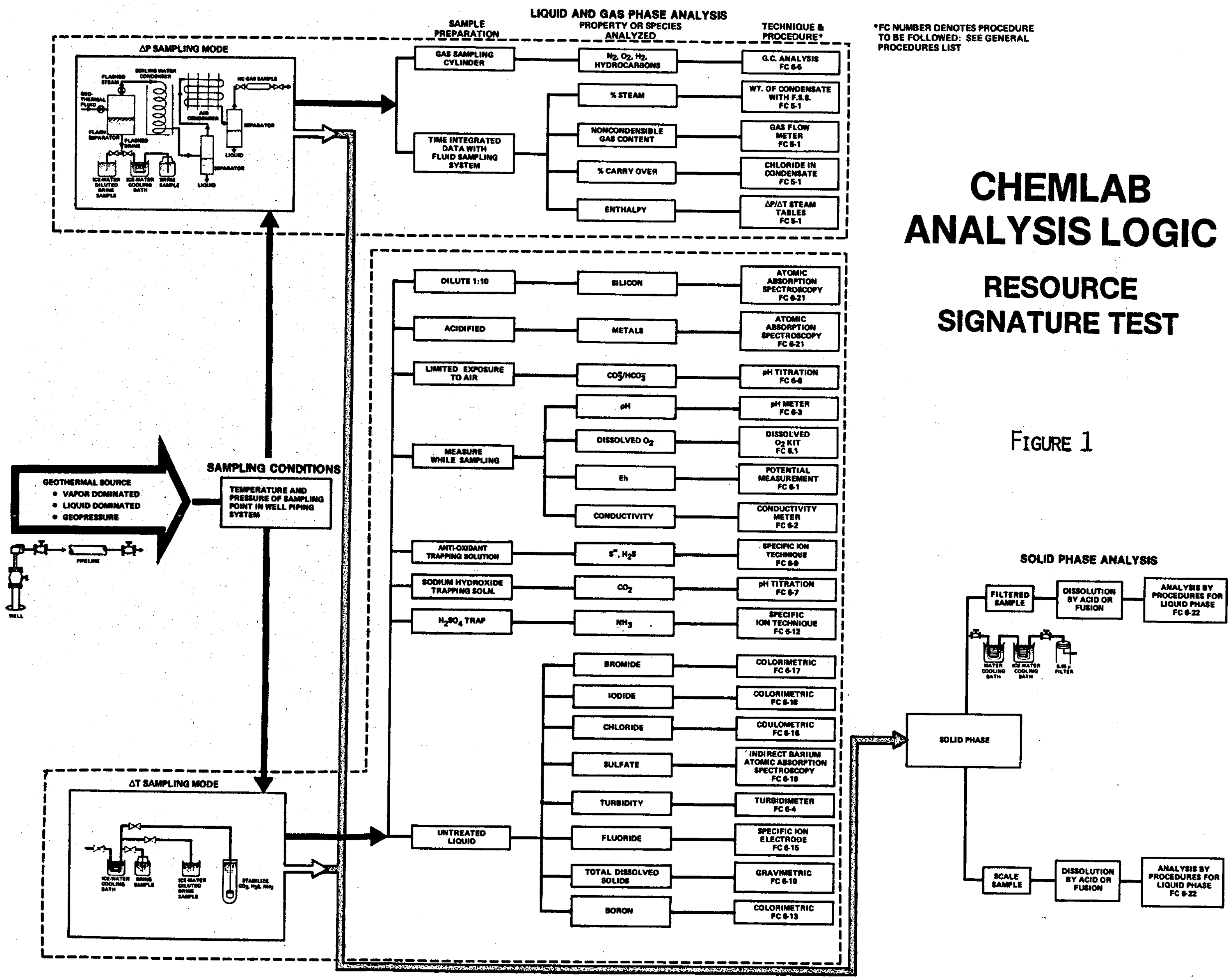
CHEMICAL SPECIES AND PHYSICAL PROPERTIES MEASURED

A.	Cations:	Ag, Al, As, B, Ba, Ca, Co, Cr, Cu, Fe, Hg, K, Li, Mg, Mn, Mo, Na, Ni, Pb, Si, Sn, Ti, V, Zn, NH_4^+
B.	Anions:	Br, Cl, HCO_3, CO_3, F, I, S, SO_4
C.	Gases:	CO_2, O_2, H_2, H_2S, N_2, hydrocarbons
D.	Properties:	TDS, conductivity, pH, E_H, turbidity, enthalpy, gas: brine ratio, steam fraction

TABLE 1

MAJOR ANALYTICAL EQUIPMENT FOR CHEMICAL ANALYSIS AND PHYSICAL PROPERTY MEASUREMENT

Equipment	Test Capability
Atomic Absorption Spectrophotometer	Analysis of Metals
UV-Visible Spectrophotometer	Colorimetric Analysis
Coulometric Chloride Meter	Chloride Ion Measurement
Automatic Titrating System	Analysis of Total Alkalinity, Carbonate-Bicarbonate
Gas Chromatographic System	Analysis of Noncondensible Gases
pH, Specific Ion Meter	Measurement of pH and Redox Potentials, Specific Ion Concentrations
Fluid Sampling System	Sampling Noncondensible Gases, Steam and Geothermal Brine
Balances	
Analytical - 200 g ± 0.2 mg	Weighing samples requiring accurate results on small samples
Top Loading Electronic - 3000 g ± 0.1 g	Weighing of large samples and quick rough weighings
Turbidimeter	Determination of turbidity
Conductivity Meter	Measurements of conductivity samples
Drying Oven	Determination of moisture content, total dissolved solids
Stereomicroscope	Microscopic examination of samples



CHEMLAB ANALYSIS LOGIC

RESOURCE SIGNATURE TEST

FIGURE 1

TABLE 3

ANALYTES CHOSEN FOR ANALYTICAL REPRODUCIBILITY TESTING

Analytes Expected To Be Stable

Analyte	Method
TDS	Gravimetry
Cl^-	Coulometric titration
CO_2 (dissolved)	pH titration
K, Na, Li, Ca, Si, Mn	Atomic absorption
B	Colorimetry
HCO_3^-	pH titration
Gases	Gas chromatography

Analytes Suspected To Be Unstable

Analyte	Method
$S^=$	Colorimetry
E_H	Redox electrode
pH	Glass electrode
O_2 (dissolved)	Membrane electrode

TABLE 4

RESULTS OF ANALYSIS REPRODUCIBILITY STUDY: STABLE GEOTHERMAL SAMPLES

Analyte	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Ave	σ*	$\lambda_{\bar{x}}$ †
TDS (mg/kg)	4120	4110	4160	4200	4110	4110	4110	-	4131	35.3	0.8%
Cl^- (mg/kg)	1980	1980	1980	1960	1980	1980	1980	-	1977	7.56	0.4%
CO_2 (mg/kg)	693	487	716	663	600	659	717	-	648	81.6	12%
K (mg/kg)	110	101	105	104	107	103	108	107	106	2.9	2.3%
Na (mg/kg)	1430	1490	1390	1410	1360	1490	1450	1440	1432	45.6	2.7%
Li (mg/kg)	3.91	4.13	4.15	4.12	4.16	4.18	4.19	4.22	4.13	0.096	1.9%
Ca (mg/kg)	23.6	24.0	23.8	24.6	25.1	23.8	23.7	24.4	24.1	0.53	1.8%
Si (mg/kg)	109	104	103	105	103	106	105	104	105	1.96	1.6%
Mn (mg/kg)	0.010	0.0085	0.0225	0.0215	0.012	0.011	0.011	0.0225	0.015	0.0061	34%
B (mg/kg)	4.53	4.55	4.85	4.62	4.65	4.75	4.51	-	4.64	0.12	2.5%
HCO_3^- (mg/kg)	429	429	427	427	431	433	431	-	430	2.2	0.5%

* Standard deviation.

† $\lambda_{\bar{x}} = \frac{t\sigma/\sqrt{n}}{\bar{x}} \times 100$, where t = Student t factor

TABLE 5

RESULTS OF ANALYSIS REPRODUCIBILITY STUDY: UNSTABLE GEOTHERMAL SAMPLES

Day 1

Analyte	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	Mean	σ*	$\lambda_{\bar{x}}$ †
$S^{=}$, mg/kg	0.186	0.164	0.135	0.160	0.119	0.176	0.141	0.163	0.156	0.022	11%
E_H, mV	-10	-125	-12	-115	-105	6	-100	-50	-64	54	69%
pH	5.87	5.86	5.87	5.87	5.87	5.95	5.88	5.88	5.88	0.029	0.4%
O_2 (dissolved), mg/kg	5.8	2.8	1.6	2.4	2.7	3.4	2.3	2.5	2.9	1.3	34%

Analyte	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Mean	σ*	$\lambda_{\bar{x}}$ †
$S^{=}$, mg/kg	0.186	0.151	0.176	0.176	0.183	0.199	0.147	0.112	0.163	0.029	16%
E_H, mV	-10	40	93	92	152	130	180	205	127	57	40%
pH	5.87	5.95	6.03	6.01	5.95	6.03	6.00	6.01	6.00	0.034	0.5%
O_2 (dissolved), mg/kg	5.8	3.1	4.0	3.7	3.7	3.6	5.2	4.4	4.0	0.68	15%

* Standard deviation

† $\lambda_{\bar{x}} = \frac{t\sigma/\sqrt{n}}{\bar{x}} \times 100$, where t = Student t factor

TABLE 6

RESULTS OF ANALYSIS REPRODUCIBILITY STUDY: GAS SAMPLES

Analyte	Day (1) (1)	(2)	(3)	(4)	(5)	(6)	Mean	σ*	$\lambda_{\bar{x}}$ †
H_2S mole %	78.5	79.7	79.8	79.2	79.1	78.6	79.2	0.54	0.7%
CH_4 mole %	11.9	12.3	12.2	12.4	12.4	12.4	12.3	0.2	2%
C_2H_6 mole %	0.139	0.142	0.142	0.144	0.144	0.144	0.142	0.002	2%
C_3H_8 mg/kg	236	230	259	256	200	195	229	27	12%
N_2 mole %	7.66	7.86	7.84	8.03	8.05	8.06	7.92	0.16	2%
H_2O mole %	3.77**	1.46	1.47	1.77	1.68	1.47	1.57	0.15	12%
H_2 mole %	0.212**	0.160	-	0.155	0.160	-	0.158	0.003	5%

* Standard deviation

† $\lambda_{\bar{x}} = \dfrac{t\sigma/\sqrt{n}}{\bar{x}} \times 100$, where t = Student t factor

** Not included in mean

within the capability of the laboratory. Auxiliary analytical capability available at Rockwell International laboratories may be used in support of special tests; x-ray diffraction of solid scale samples is the most frequent example.

To ensure the reliability of all data generated on the mobile geothermal laboratory, a series of quality control procedures has been developed. These include collection of multiple samples or measurement during sampling of unstable species and performance of multiple analyses for most chemical species. Chemical measurements are made against commercially prepared analytical standards and instrument calibration is routinely checked during analytical activities. Control solutions are measured along with standard and sample solutions; these controls are the same solutions at each field site and so provide a valid measure of the reproducibility of the analytical measurements at different sites. Before a control solution is completely used, another is prepared and the solutions are cross-checked, assuring continuity of measurement as the laboratory moves from one site to another. All sampling and analytical procedures conform to the standard quality control and quality assurance procedures used in the Rockwell International Environmental Monitoring and Services Center laboratories.

East Mesa, CA Site Visit, August - September 1980 In August 1980, the mobile laboratory traveled to the East Mesa, CA geothermal site to conduct reproducibility tests on the sampling and analytical procedures and to conduct a signature test on East Mesa Well 8-1. The results of the reproducibility tests were used to modify the quality control procedures, the sampling procedures, and the analytical procedures used on the mobile laboratory.

Analysis reproducibility tests were designed to demonstrate the reliability of analytical measurements made in the laboratory; a collection of species, representative of the types of species measured and analytical methods used, was chosen for the analysis reproducibility tests. These species are listed in Table 3, in two groups, those expected to be stable and those suspected to be unstable. Each chemical species measured as a liquid sample was measured once a day for eight days, and in addition those species suspected to be unstable were measured eight times the first day. Gas samples were measured six times the same day. Repetitive measurements were made on aliquots of the same solution. Statistical analyses were conducted on all repetitive measurements. The results for the stable species are presented in Table 4, those for the unstable species in Table 5, and those for the gases in Table 6.

From Table 4, it is clear that most of the samples are stable over an eight-day period for the analysis of those species listed, and that the analyses are reproducible. Two of the analyses gave a 95% confidence interval larger than 10%: total CO_2 and Mn. Samples for total CO_2 should be considered potentially unstable; procedures have been modified to specify analysis as soon as possible after the sampling. The measured value for Mn, 0.015 mg/kg was very close to the detection limit of 0.01 mg/kg and so the high confidence interval is not unexpected. Analysis of the results for those species suspected to be unstable indicate that precautions should be taken during these measurements; sulfide, E_H and dissolved oxygen have unacceptable reproducibility. As a result of these studies, a flow-through sampling probe has been fabricated and E_H, pH, and dissolved oxygen are measured while sampling. The measurement of $S^=$ is performed as soon after sampling as possible. The analyses for gases gave satisfactory results; twelve percent reproducibility was achieved for the propane fraction, which was very near the detection limit of 200 mg/kg, and for the gaseous water fraction.

Experiments were conducted to examine the reproducibility of results on samples collected in the ΔP and ΔT modes. Again a small subset of the signature test analytes was chosen for the test; these are listed in Table 7. Samples for each measurement were collected in the ΔP mode and in the ΔT mode, and then analyzed for the chosen species. The results of these analyses are presented in Table 8.

Differences brought about by the two different sampling modes were insignificant for the analyses of TDS, Cl^-, Si, and enthalpy. In the other cases, the samples reflect the effect of the different sampling modes on the chemical equilibria involving CO_2 and H_2S dissolution in the liquid samples and the $CO_3^=$ and $S^=/H_2S$ equilibria in solution. In the ΔT sampling mode, CO_2 and H_2S remain in solution upon sampling, while in the ΔP mode, they may flash from the solution under the reduced

TABLE 7

ANALYTES CHOSEN FOR SAMPLING REPRODUCIBILITY TESTING

Analyte	Method
TDS	Gravimetry
Cl^-	Coulometric titration
Cu, Mn, Si	Atomic absorption
$CO_3^=$, HCO_3^-	pH titration
$S^=$	Colorimetry
Enthalpy	$\Delta P/\Delta T$ steam tables

TABLE 8

RESULTS OF SAMPLING REPRODUCIBILITY STUDY

Analyte	Sampling Mode	
	ΔP	ΔT
TDS (mg/kg)	4150	4200
Cl^- (mg/kg)	2055	2030
Ca (mg/kg)	11.3	25.1
Mn (mg/kg)	(0.004)*	0.03
Si (mg/kg)	98	95
$CO_3^=$ (mg/kg)	28.5	0
HCO_3^- (mg/kg)	332	437
$S^=$ (mg/kg)	0.24	0.45
Enthalpy (BTU/lb)	287	280

*Estimate, value was below detection limit of 0.01.

pressure, giving less representative samples. As a result of these experiments, procedures were modified to specify collection of samples to be analyzed for total CO_2, total $H_2S/S^=$, metals, and anions in the ΔT mode. Non-condensible gas samples are collected in the ΔP mode.

Following the reproducibility tests at East Mesa, a signature test was performed to characterize the geothermal fluid from well 8-1. The results of the signature test are presented in Table 9.

The geothermal fluid from East Mesa Well 8-1 has significant ionic content, with the major components being calcium, potassium, sodium, silicon, chloride, bicarbonate, and sulfate. Minor components include boron, lithium, ammonium, strontium, and fluoride, and trace components include arsenic, barium, iron, magnesium, manganese, sulfide, and zinc. The most abundant gaseous component is carbon dioxide, while nitrogen and methane are also present in significant quantities, and hydrogen, water, ethane, and propane are present in small quantities.

Brazoria County, TX Site Visit, October 1980 In October 1980, the mobile laboratory travelled to the DOE geopressure facility in Brazoria County, TX to conduct signature tests on Pleasant Bayou well number 2. Because the brine pressures at the wellhead (3600 psig) exceeded the capacity of the fluid sampling system (1000 psig), samples were collected downstream of the separator (800 psig) from both the gas stream and the liquid stream. Figure 2 is a simplified diagram of the system. The sample values were then normalized to the original wellstream using flow values obtained from site personnel.

Two signature tests were performed on Pleasant Bayou well number 2; for the first, samples were collected from the separator gas outlet (A, Figure 2) and from a sample cock downstream of the separator dump valve (C, Figure 2) and for the second, both gas and liquid samples were collected from a sample cock upstream of the separator dump valve (B, Figure 2). The results of the analysis of gases collected at the gas outlet and upstream of the dump valve were very different. These results are presented in Table 10. The differences in gas concentrations at the two sampling sites reflect the differences in water solubility among the gases. Carbon dioxide is very soluble in water and so is found in a large concentration in the liquid stream. The hydrocarbons, in contrast, dissolve very little in water and so are found primarily in the gas stream. The data for the signature test on Pleasant Bayou well number 2 are presented in Table 11; all values are normalized to represent the wellstream (before the separator) values.

TABLE 9

SIGNATURE TEST RESULTS SUMMARY, EAST MESA WELL 8-1

Analyte	Result	Analyte	Result
TDS, mg/kg	4100	Br^-, mg/kg	ND (8)
Conductivity, μmho/cm	7290	Ca, mg/kg	245 (0.01)
pH	5.55	Cl^-, mg/kg	1980
E_H, mV	-213	Co, mg/kg	ND (0.05)
Dissolved O_2, mg/kg	0.15	$CO_3^=$, mg/kg	ND (30)
Turbidity, NTU	0.18	CO_2, mg/kg	*
Enthalpy, BTU/lb	280	Cr, mg/kg	ND (0.05)
Gas/brine ratio, l/kg	15	Cu, mg/kg	ND (0.02)
Steam fraction, %	8.95	F^-, mg/kg	3.7
Ag, mg/kg	ND† (0.01)	Fe, mg/kg	0.98
Al, mg/kg	ND (0.1)	HCO_3^-, mg/kg	426
As, mg/kg	0.3	Hg, mg/kg	ND (0.2)
B, mg/kg	4.7	I^-, mg/kg	ND (0.05)
Ba, mg/kg	0.60	K, mg/kg	109

(continued)

TABLE 9 (con't)

SIGNATURE TEST RESULTS SUMMARY, EAST MESA WELL 8-1

Analyte	Result	Analyte	Result
Li, mg/kg	4.15	Sr, mg/kg	2.97
Mg, mg/kg	0.90	Ti, mg/kg	ND (0.4)
Mn, mg/kg	0.031	V, mg/kg	ND (0.2)
Mo, mg/kg	ND (0.1)	Zn, mg/kg	0.008
Na, mg/kg	1428	CO_2 (gas), mg/kg	22083
NH_3, mg/kg	9.2	H_2 (gas), mg/kg	0.20
Ni, mg/kg	ND (0.04)	H_2O (gas), mg/kg	180
Pb, mg/kg	ND (0.1)	H_2S (gas), mg/kg	ND (5)
$S^=$, mg/kg	0.47	N_2 (gas), mg/kg	1400
Sb, mg/kg	ND (0.2)	CH_4 (gas), mg/kg	1250
Si, mg/kg	93	C_2H_6 (gas), mg/kg	30.3
Sn, mg/kg	ND (0.8)	C_3H_8 (gas), mg/kg	5.6
$SO_4^=$, mg/kg	119	C_4H_{10} (gas), mg/kg	ND (5)

† Not detected (detection limit).

* Traps saturated.

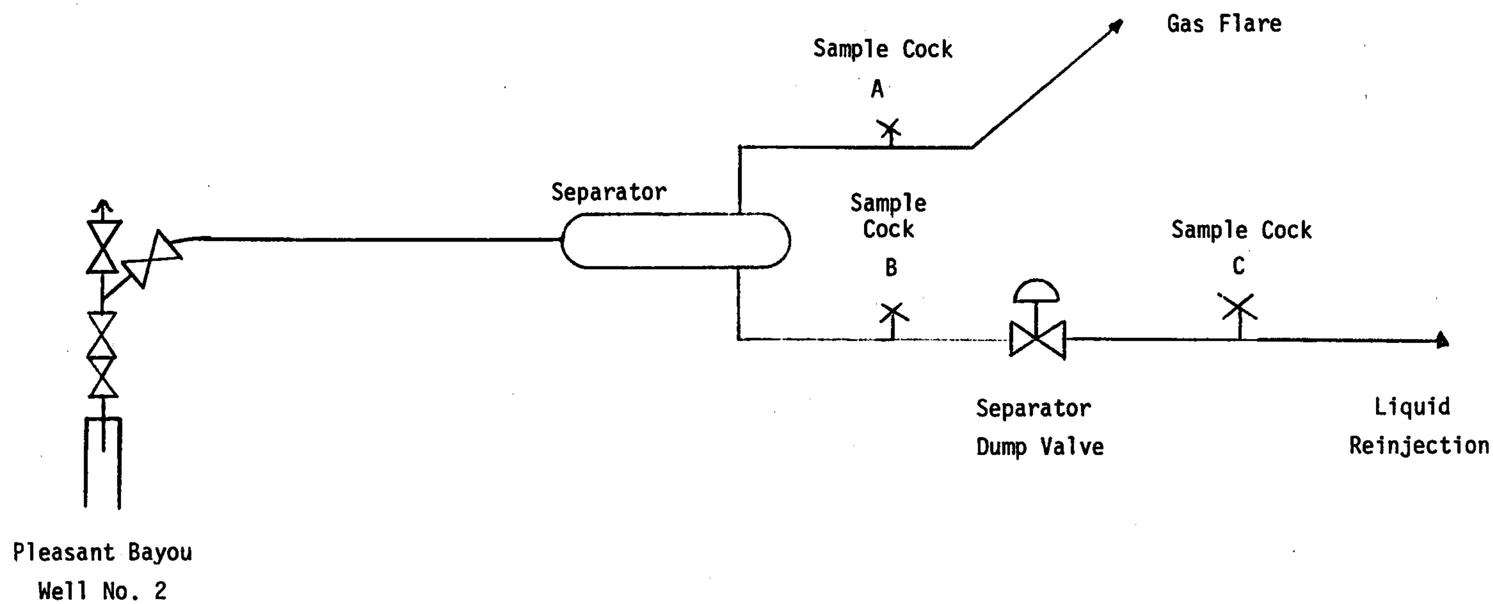


Figure 2. System Diagram

DOE GEOTHERMAL SITE, BRAZORIA COUNTY, TX.

TABLE 10

NON-CONDENSIBLE GASES MEASURED

AT PLEASANT BAYOU WELL NUMBER 2

	Location	
Analyte	Gas Outlet (A)**	Upstream of Dump Valve (B)**
CO_2 (gas)	267630*	763000
H_2 (gas)	31	81
H_2O (gas)	ND†	10600
H_2S (gas)	ND	ND
N_2 (gas)	8350	2380
CH_4 (gas)	666400	212700
C_2H_6 (gas)	25980	6560
C_3H_8 (gas)	25880	2880
C_4H_{10} (gas)	4794	531

* Values are mg/kg of gas at the site of collection.
† Not detected
**See Figure 2

TABLE 11

SIGNATURE TEST RESULTS SUMMARY, PLEASANT BAYOU WELL NUMBER 2

Analyte	Result	Analyte	Result
TDS, mg/kg	124500	Br^-, mg/kg	52
Conductivity, μmho/cm	1.4×10^5	Ca, mg/kg	7231
pH	5.18	Cl^-, mg/kg	72100
E_H	-37	Co, mg/kg	ND (0.05)
Dissolved O_2, mg/kg	ND (0.05)	$CO_3^=$, mg/kg as $CO_3^=$	ND (30)
Turbidity, NTU	4.2	$CO_3^=$, mg/kg, total	12600
Enthalpy, BTU/lb.	224	Cr, mg/kg	0.07
Gas/brine ratio, l/kg	4.30	Cu, mg/kg	0.03
Steam fraction, %	3.4	F^-, mg/kg	2.0
Ag, mg/kg	ND (0.01)	Fe, mg/kg	80.7
Al, mg/kg	ND (0.1)	HCO_3^-, mg/kg	191
As, mg/kg	ND (0.2)	Hg, mg/kg	ND (0.2)
B, mg/kg	26	I^-, mg/kg	8
Ba, mg/kg	817	K, mg/kg	504

(continued)

TABLE 11 (con't)

SIGNATURE TEST RESULTS SUMMARY, PLEASANT BAYOU WELL NUMBER 2

Analyte	Result	Analyte	Result
Li, mg/kg	28.3	Sr, mg/kg	947
Mg, mg/kg	612	Ti, mg/kg	ND (0.4)
Mn, mg/kg	20.3	V, mg/kg	ND (0.2)
Mo, mg/kg	ND (0.1)	Zn, mg/kg	0.751
Na, mg/kg	37097	CO_2 (gas), mg/kg	2169
NH_3, mg/kg	77	H_2 (gas), mg/kg	0.24
Ni, mg/kg	0.094	H_2O (gas), mg/kg	17.8
Pb, mg/kg	0.85	H_2S (gas), mg/kg	ND (0.5)
$S^{=}$, mg/kg	0.125	N_2 (gas), mg/kg	31.7
Sb, mg/kg	ND (0.2)	CH_4 (gas), mg/kg	2209
Si, mg/kg	55.3	C_2H_6 (gas), mg/kg	97
Sn, mg/kg	ND (0.8)	C_3H_8 (gas), mg/kg	91
$SO_4^{=}$, mg/kg	ND (10)	C_4H_{10} (gas), mg/kg	17

The geothermal fluid for Pleasant Bayou Well number 2 has a very high ionic content, of which the major components are barium, calcium, potassium, magnesium, strontium, and chloride. Minor components are boron, iron, lithium, manganese, ammonium, silicon, bromide, fluoride, bicarbonate, and iodide, and trace components are chromium, copper, nickel, lead, zinc, and sulfide. The most abundant gases are carbon dioxide and methane, while ethane, propane, butane, hydrogen, water and nitrogen are present in measurable quantities. Sodium hydroxide traps were saturated during the collection of samples for the measurement of total CO_2, indicating very large concentrations. Techniques for the collection of total carbon dioxide need additional improvement.

Recent Activity, 1981 The mobile laboratory travelled to a demonstration geothermal power plant at Brawley, CA to conduct signature tests of the geothermal fluid, tracking tests of important chemical components at six sites around the system, and a special test on a scale sample.

The laboratory then travelled to a well site at Dixie Valley, NV in support of the test of a heat exchanger; a signature test on the brine entering the heat exchanger was performed along with tracking tests on the fluid at four ports within the heat exchanger and special tests of solid scale samples taken from within the heat exchanger.

Planned Activity, 1981 The mobile laboratory will travel in the future to conduct signature tests at hydrothermal and geopressure facilities, to collect data for the EPRI brine data base. In addition, it will lend support to EPRI field tests including tests of a rotary separator turbine, an upstream hydrogen sulfide removal process, and a steam separator.

BRAWLEY 10 MWe GEOTHERMAL POWER PLANT

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Southern California Edison Company's Brawley Geothermal Electric Project is the first flash-steam project in the United States to successfully demonstrate the feasibility of utilizing steam from highly saline geothermal fluids for electric power generation.

The Brawley Unit 1 power plant is an experimental effort by Southern California Edison and its preceding companies which have long been interested in developing geothermal electric generating plants. In 1973, Edison began looking strongly in the California Imperial Valley area for geothermal energy development. At Brawley, wells drilled there were found to be capable of producing geothermal fluid for potential commercial electric power.

On July 14, 1978, Edison and Union Oil Company of California signed a contract which provided for the construction of the first geothermal flash-steam electric generating plant in the Imperial Valley. The Brawley 10 MWe power plant was commissioned on July 21, 1980, with commercial operating beginning on July 29, 1980. The plant, after 8 months of operation, has demonstrated an average operating availability factor of 79 percent with an average capacity factor of 51 percent.

The objective of the Brawley 10 MW Unit 1 program is to assess the technical and economic feasibility of generating electricity from steam produced from highly saline geothermal fluids. The Edison plant is designed specifically for utilization of geothermal steam, and it employs design principles found in conventional fossil-fueled, electric generating plants.

The geothermal energy production system operated by Union Oil at Brawley utilizes a flashed steam system. Geothermal hot brine fluids are brought to the surface under pressure and moved through a succession of vessels where the pressure is reduced, allowing a portion of the fluid at each vessel to separate into steam. This steam is delivered to Edison at a design rate of 94,800 kg/hr (209,000 lbs/hr) at a single pressure of 115 psia and saturation temperature of 170°C (340°F).

The Brawley plant is designed to produce 10,000 kilowatts of gross electric power. The load to run the plant itself is just under 800 kw. The remaining 9200 kw of plant output power is sold to the Imperial Irrigation District, the local utility, for consumption in the Imperial Valley. The amount of power generated by this plant is sufficient to meet the needs of approximately 9200 residential consumers, and can save approximately 100,000 barrels of oil per year.

The Brawley 10 MW power plant is a model of a full-scale commercial plant, using systems and components which likely will be utilized in large-scale follow-on units. Evaluation of this plant will help determine the future use of geothermal energy as a viable replacement for fossil fuels in an effort to balance the use of all energy sources for electric power generation and consumption.

ASSESSMENT PROGRAM-OPERATING DATA
BRAWLEY GEOTHERMAL PROJECT UNIT 1

MONTH	GROSS GENERATION KWh	AUX ENERGY KWh	EMERG ENERGY KWh	MAKEUP PUMPS KWh	NET GENERATION KWh	CAP FAC %	AVAIL FAC %	TOTAL DOWN TIME HRS	FORCED OUTAGE RATE %	SCHED OUTAGE RATE %	AVG UNIT LOAD MW
1980 JULY	2,020,000	153,600	9,600	5,220	1,851,580	27	45	408.5	21.6	33.3	6.0
AUG	3,430,000	382,600	3,520	9,860	3,034,020	46	73	203	23	4	6.6
SEPT	3,830,000	392,000	1,920	14,620	3,421,460	53	95	37	2.7	2.4	5.6
OCT	3,120,000	286,200	960	13,150	2,819,690	42	81	142	2.7	16.4	5.2
NOV	4,190,000	300,600	960	8,340	3,880,100	58	67	234.5	6.2	26.4	8.4
DEC	3,340,000	338,200	960	7,870	2,992,970	45	89	79	8	2.5	5.1
1981 JAN	2,870,000	261,000	2,560	6,960	2,599,480	39	64	270	1.5	34.7	6.5
FEB	4,450,000	351,000	960	10,680	4,087,360	66	84	110	1.2	15.2	8.0
MAR	4,330,000	273,000	1,280	11,640	4,044,080	58	77	172	8.8	14.4	7.5
APR											
MAY											
JUNE											

MAGMA'S 11.2 MWe BINARY PLANT

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Escondido, CA 92025 (714) 743-7008

The East Mesa presentation this year was an update of the 1980 report. Readers are referred to EPRI TC-80-907, December 1980, Proceedings of the Fourth Annual Geothermal Conference and Workshop, pp. 5-1 to 5-14.

Dup

RAFT RIVER GEOTHERMAL FACILITY

DOE-Idaho Operations Contract No. DE-AC07-76ID01570

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Introduction The Raft River Geothermal Facility is operated by EG&G Idaho, Inc., for the Department of Energy. The major feature of this facility is a binary pilot plant with a nominal gross rating of 5MW(e)[1], when supplied by a geothermal resource of 143°C (290°F) or greater. Isobutane is used as the working fluid in a two stage boiling cycle which provides high and low temperature streams to a double impeller radial inflow turbine. The turbine-generator, heat exchangers and feed pumps were designed for "floating power"[2] operation, thereby enabling the plant to produce significantly more power in the winter months than at the summer design condition. Geothermal water is being used for heat rejection. Its use has caused scaling and corrosion problems and has required special treatment[3]. Geothermal fluid is supplied by three production wells. There are two injection wells. Cement-asbestos pipe is used to transmit the geothermal fluid.

In addition to the 5MW(e) pilot plant, a 60kW(e) binary system and a water treatment laboratory is located at the Raft River Facility which is used for conversion system research.

This paper will provide an update on the power conversion activities at the Raft River Facility.

5MW(e) Pilot Plant Status The power plant, shown in Figures 1 and 2, is essentially complete. Plant startup has been delayed approximately one year (from October, 1980) due to delays in completing construction, modifications and uncertain funding for FY-82. Recent developments indicate some funding will be available in FY-82 to permit testing and operation to proceed on a limited basis. A new startup schedule is being prepared and means of operating with a reduced crew is being investigated.

Geothermal Supply Pumps The downhole pump experience at Raft River has been very poor. Original plans were to use submersible pumps; however, all that have been installed and tested have failed[3]. During the past year a large horsepower submersible pump was installed and tested, and even though it was specifically designed for geothermal applications, it failed in about four hours. Smaller conventional submersible pumps were operated longer but eventually failed.

Current plans are to install new line shaft pumps (Peerless) in wells RRGE-1 and RRGE-2. These pumps will have lead bronze bearings lubricated by water in which a soluble oil has been added. Delivery of these units will be completed by mid-July. A line shaft pump (Peerless) with Teflon bearings and no lubricating fluid is currently installed in well RRGE-3. The installed depths, rated conditions and horsepower of these pumps is given in Table 1.

TABLE 1 GEOTHERMAL SUPPLY PUMP RATINGS - SHAFT DRIVEN

Well No.	Set Depth, m (ft)		Flow m/s (gpm)		TDH, m (ft)		Motor hp
RRGE-1	305	(1000)	.071	(1120)	408	(1340)	500
RRGE-2	305	(1000)	.043	(680)	408	(1340)	350
RRGE-3	304	(998)	.024	(375)	434	(1425)	250

Cooling water treatment test programs[4,5] to establish the best treatments for removal of silica and hardness from the makeup water, corrosion protection for the carbon steel condenser tubes, and scale control have been concluded. Although a chromate based treatment provided the best corrosion protection, a phosphate based inhibitor treatment has been adapted to eliminate potential environmental concerns. The condenser tubes were cleaned and passivated. The inhibitor treatment will consist of a combination of polyphosphate, orthophosphate, zinc and a copper inhibitor. The cooling tower will be operated at approximately eight cycles of concentration.

Testing has shown that scale formation cannot be controlled if silica levels greater than approximately 25-30 ppm are permitted in the cooling system. This low limit is due to the presence of dissolved iron in the cooling water. Thus, when operating the cooling water system at eight cycles of concentration, the silica in the makeup water must be reduced to about 3 ppm. Reduction of silica to such low levels is very costly.

The problem of silica removal from makeup water is not unique to Raft River. Ground waters in the Basin and Range regions in which many geothermal areas are located have silica levels up to approximately 60 ppm. Thus, silica removal will be required to prevent precipitation when the water is concentrated in the cooling system. Large reductions in the cost of silica removal can be achieved if cooling systems are designed to eliminate ions causing silica precipitation from entering the system. Concentrations approaching approximately 120 ppm should be achievable without the use of dispersants and perhaps double that level will be possible with dispersants. The water treatment testing program in progress at Raft River will establish the actual limits.

During the past year Permutit Company conducted tests on silica removal using reverse osmosis and rusting iron in a sidestream system(6). The rusting iron shows significant promise as an inexpensive means for removing silica.

Condenser Tube Materials Corrosion testing to determine a preferred tube material for the 5MW plant condenser is in progress. Two types of tests are being performed: spinner tests which are used to screen materials and pilot cooling tower tests which expose actual tubing to conditions more representative of an actual system. Figure 3 shows the spinner apparatus in which small coupons are moved through the aerated brine. Figure 4 shows the pilot cooling tower set up. To date approximately 35 materials have been tested in the spinner apparatus and four materials are presently being tested in the pilot towers. Preliminary results based upon weight loss and inspection for pitting indicate that the better materials are: Sea Cure (A-268-79A), AL 6X (A-268), 70/30 Copper/Nickel (B-359-B111) and AL 29-4-C (A-268).

These materials cost about 2 to 3.5 times as much as carbon steel but are much less expensive than Inconel, Hastelloy and other very corrosion resistant materials.

Although these tests are being performed to establish an alternative material for the 5MW plant condenser, the results, we believe, have a great generic value and should benefit anyone selecting materials for a binary system condenser when relatively poor quality cooling water is available.

Performance Predictions The geothermal fluid temperature at the pilot plant is expected to be about 138°C (208°F) rather than the 143°C (290°F) design value. Parameter studies(7) have been conducted to investigate the effect on performance of a lower geothermal fluid temperature and to establish equipment operating limits encountered when changing geothermal flow to compensate for the lower temperature. The results of this investigation may be summarized as follows:

1. A decrease of 5.5°C (10°F) in the geothermal fluid temperature will result in a reduction in power output of about 8%.

2. Power lost by reduced geothermal fluid temperature can be partially made up by increasing the geothermal flow.

3. The feed pump (head) appears to be the most restrictive component to achieve maximum possible performance for the large variations encountered with floating power and heat exchanger fouling. The performance study suggests that a variable speed, or a two speed pump might be valuable and permit increased performance (several percent gain).

4. The dual boiling system appears to be self compensating with respect to the flow split as resource temperature decreases. No changes in turbine nozzle areas appear to be required.

5. Power output was estimated to be 33% greater in the winter than in the summer.

60kW Prototype Power Plant The Prototype Power Plant (PPP) is a small 60kW binary plant (Figure 5) which is part of the DOE Conversion Technology Program. The system configuration is modified as required to conduct test programs. The first part of the program was to conduct a series of performance tests, to gain operation experience and to operate the plant in an automatic mode. A detailed report of the experience with this plant during this phase is given in Reference 8. Operational problems encountered were:

1. Isobutane contamination with nitrogen which drastically reduced condenser performance.

2. Considerable leakage of isobutane even though retorquing of flanges, tightening of packing, etc., was conducted on a regular basis.

3. Winter operation caused several problems: power outages occurred frequently causing plant shutdown which leads to a potential vacuum hazard, difficulties were encountered with plant fill and drain back to storage, and the usual problems of tower icing and freezing of water and instrument lines existed.

The plant was operated about 87% of the time that geothermal water was available. Variation in power due to variations in ambient conditions were determined. Daily power variations were found to be 25-30% during the summer and 10-15% during the winter. Often when considering power variation, only the first order change between summer and winter is considered. These data show that very substantial variations in the daily power output must be considered as well (in the cooler climates).

Conclusion The foregoing discussions show that much is being learned about the use of geothermal power systems. Plants such as those at Raft River and elsewhere demand that activities focus on the real problems and their solution. This experience can be gained in no other way. The Raft River facilities have features that are being applied for the first time, some are developmental, others will yield new experiences to be added to the data base, and all will ultimately be factored into the design of commercial plants. The following summarizes areas in which the 5MW(e) Raft River Facility is unique or will add significantly to our understanding of geothermal power production:

- Staged (dual) boiling cycle performance
- System designed for floating power
- Radial inflow turbine performance
- Geothermal water used for heat rejection
- Fault controlled hydrothermal system behavior
- Submersible geothermal supply pumps
- Stimulated wells
- Environmental baseline

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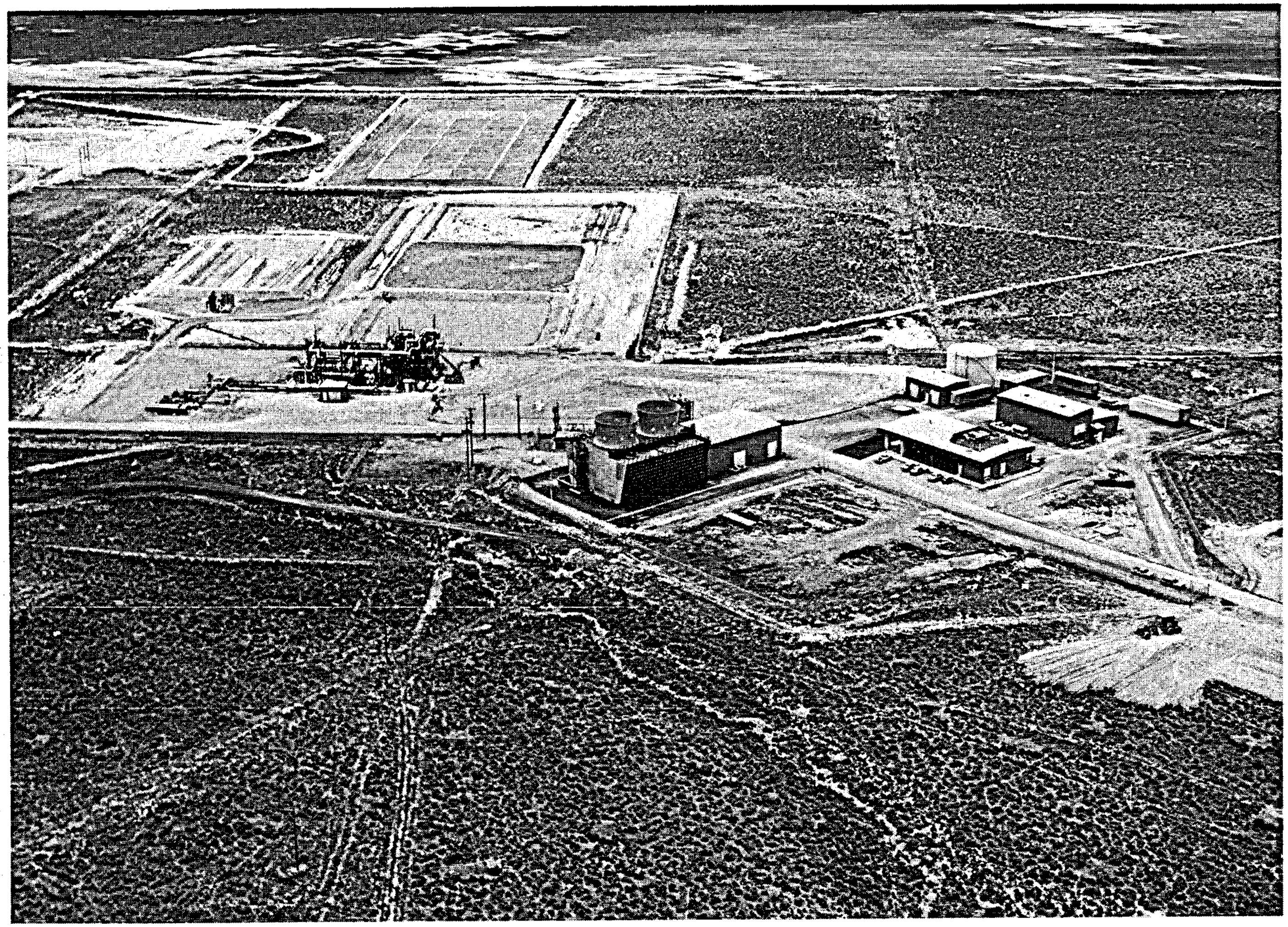

FIGURE 1 AERIAL VIEW 5MW PILOT PLANT FACILITY

Right - Control, Office and Lab Building, Maintenance Building
Center - Cooling Tower and Adjoining Water Treatment Building
Left - Process Area, Flare Pit, Holding Ponds

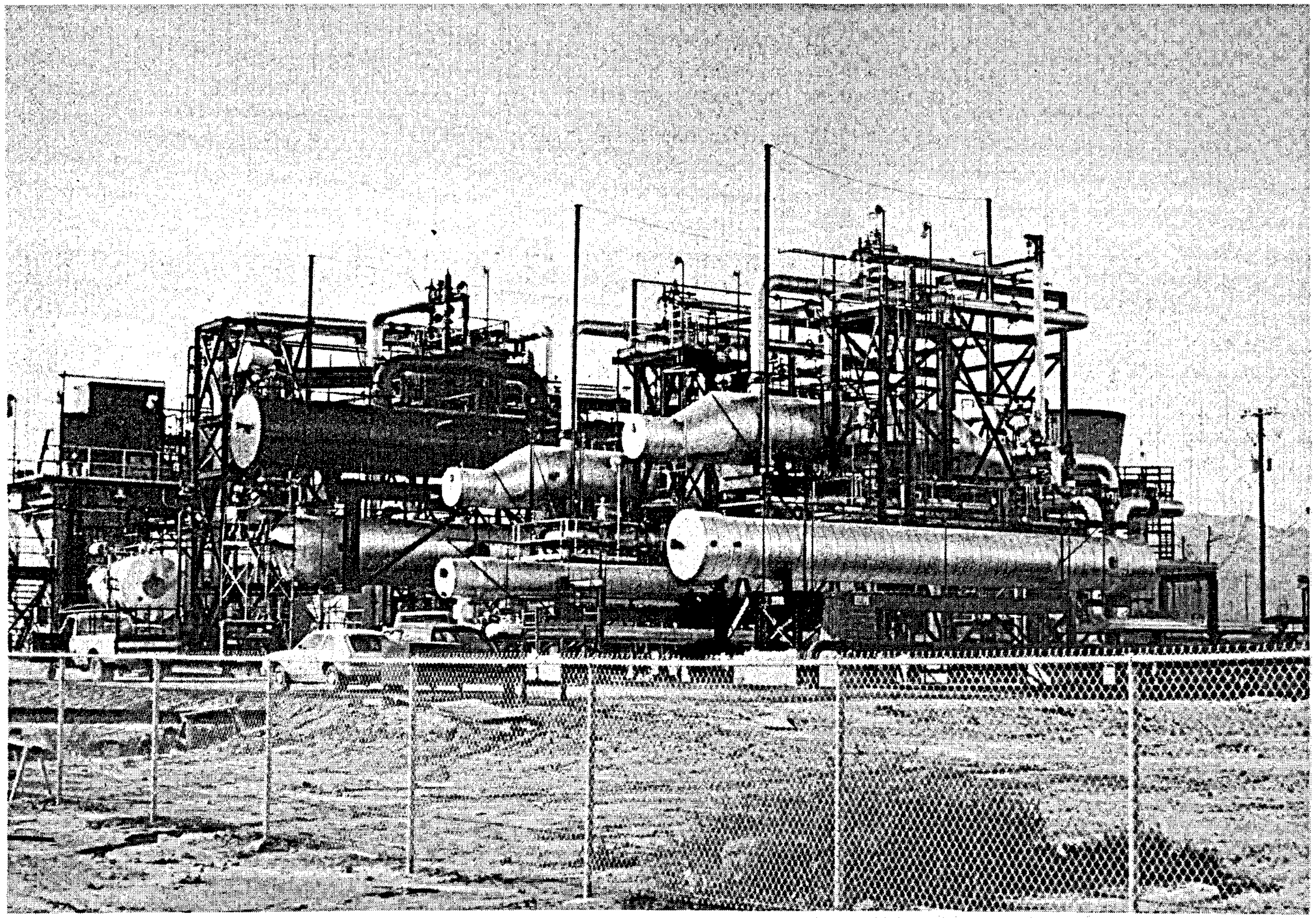

FIGURE 2 RAFT RIVER 5MW(e) PILOT PLANT PROCESS AREA

Right - L.P. Preheater (lower), L.P. Boiler (upper)
Center - H.P. Preheater (lower), H.P. Boiler (upper)
Left - Condenser (upper), Condensate Receiver (lower)
Extreme Right - Generator (upper), Oil System (lower)

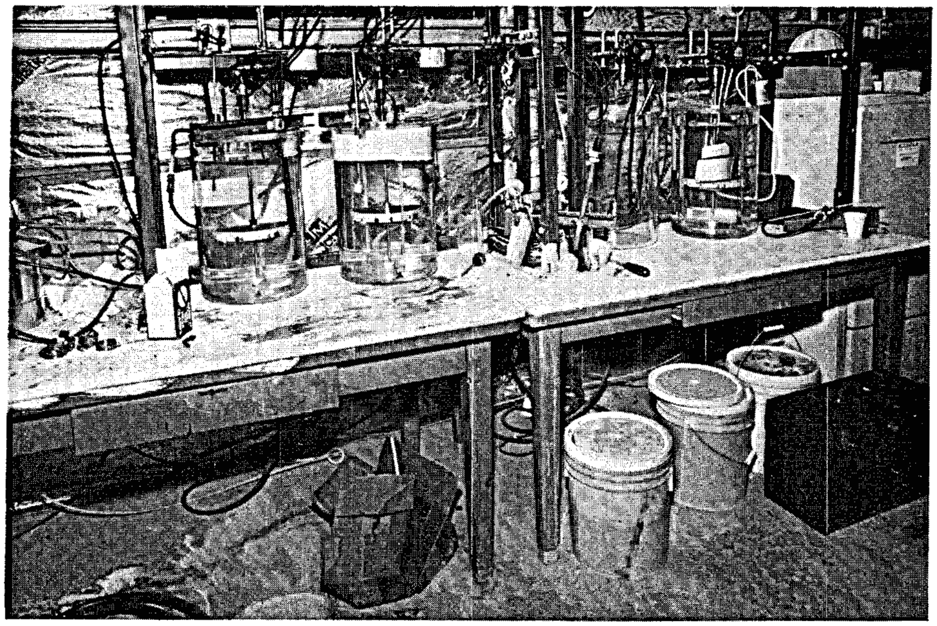

FIGURE 3 WATER CHEMISTRY LABORATORY
Spinner Apparatus used for Screening Corrosion Tests

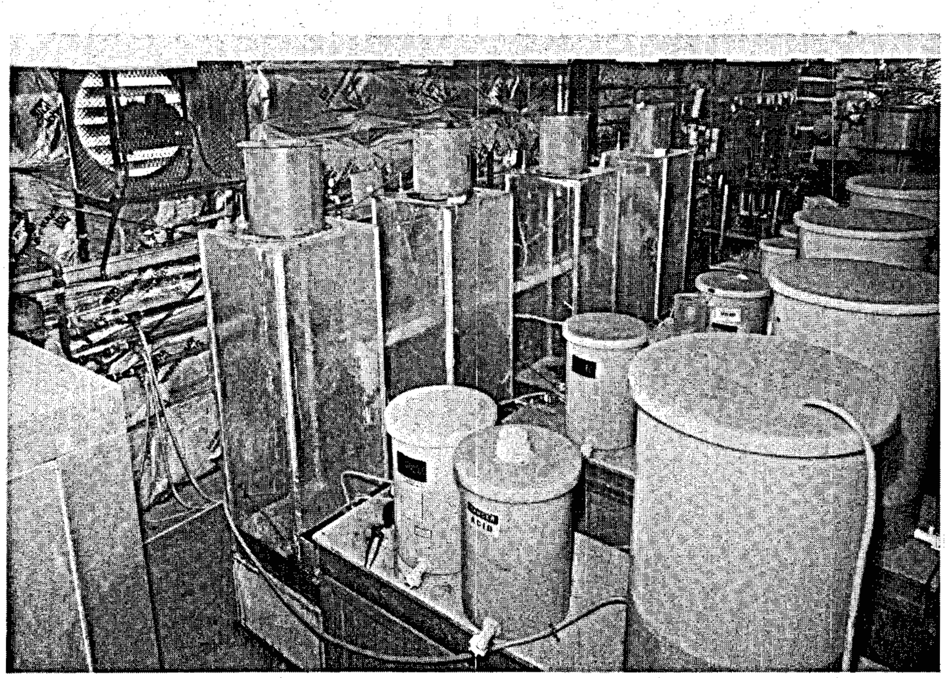

FIGURE 4 WATER CHEMISTRY LABORATORY
Pilot Cooling Towers used for Establishing Water Treatment and Corrosion Tests (tubes in heat exchangers on the wall)

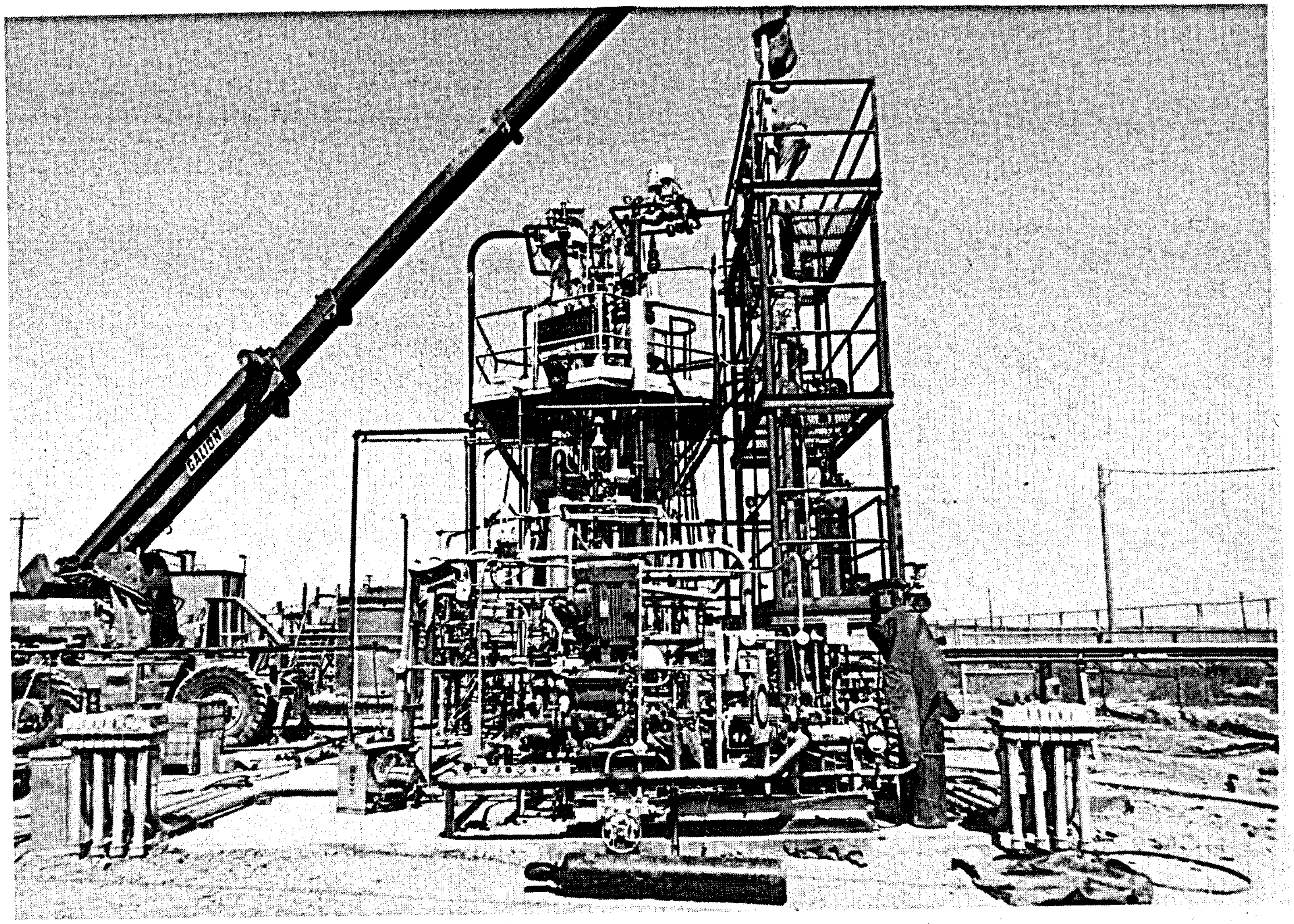

FIGURE 5 60kW(e) PROTOTYPE POWER PLANT FACILITY

Right - (within scaffold) Sieve Tray Preheater, Boiler Column
Center - Structure (right side) Shell and Tube Preheater Boiler
(left side) Vertical Fluted Tube Condenser (by ORNL)
Background - Water Treatment Facility

THE FINANCIAL COMMUNITY'S PERSPECTIVE ON THE ROLE OF DEMONSTRATION PROJECTS IN THE DEVELOPMENT OF GEOTHERMAL ENERGY

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For a new technology to achieve significant use in the electric power industry, it is generally thought that the technology must pass through three stages: scientific feasibility, demonstration and commercialization. At present, geothermal energy is passing through its demonstration stage and appears poised to enter the takeoff phase of full scale commercialization. Should the geothermal industry make this transition over the next few years, it is expected to make a noticeable contribution to U.S. energy needs during the late eighties and nineties, particularly in the western United States. My talk will focus on the perceptions of the financial community on the progress which geothermal energy is making in its demonstration stage.

Like the utility industry, financial institutions have not wanted to finance geothermal technology until it has been successfully demonstrated as both feasible and economic. This lack of confidence is reflected in the limited participation of the financial community in geothermal energy development. For example, there are now only two commercial banks actively financing geothermal projects and, for the most part, their financings have been done under the DOE's Geothermal Loan Guaranty Program.

Commercial banks, however, are ready to assist creditworthy parties in financing the development of geothermal projects without a DOE guaranty, assuming they have a full corporate guaranty for the life of the project. Indeed, this may be the only financing option available, since the Reagan administration has recommended to Congress that the Geothermal Loan Guaranty Program be eliminated along with most other research and development activities in geothermal energy. The impact of these actions will not be favorable on the industry and it may change the course of geothermal development. For example, it may lead to more "demonstration plants" being built before larger scale plants are constructed, a trend being reinforced by other technical, regulatory and economic considerations.

This is not to say that the outlook for geothermal development is poor. The outlook at The Geysers, for example, is very good and is illustrative of what will happen during commercialization. Here the pace of development is accelerating. The diversity of participants is increasing. Natomas' buyout of Magma Power Company's quarter-interest in The Geysers for $400 million indicates the value of such holdings. Commercial banks are now prepared to provide production payment loans on developed portions of this resource and traditional "project financings" for development programs are now being discussed where guarantees will run only through completion (completion being defined as several months of continuous operation at a predetermined percent of capacity). Major prerequisites for obtaining such financings are the ability to provide a satisfactory completion guaranty, the drilling of several successful exploratory wells (confirming the presence of a steam resource in commercial quantities), and a steam sales contract from an established utility. All this has come about because of the demonstrated reliability of this field for power generation purposes as well as the improving economics of geothermal development brought on by rising energy prices. Techniques to abate hydrogen sulfide have reduced lenders' environmental concerns and the regulatory environment also appears increasingly favorable.

Yet it is well recognized that The Geysers is a resource of exceptional quality. For the use of geothermal energy to become widespread, it must become equally feasible and nearly as economic to exploit hot water resources, particularly in the Imperial Valley. This area is now the focus of development activities for several reasons: its tremendous potential (some 3,000-7,000 MW) and high temperatures as well as its proximity to the major, expanding markets of southern California which are largely dependent on oil, not coal or nuclear energy, for electrical generation. Finally, to the extent that the technical problems caused by the hypersaline and corrosive brines in the Imperial Valley can be solved, it portends well for the use of any geothermal resource in the western United States.

There are now two demonstration plants in the Imperial Valley. As we have heard, these have been a mixed success, due to a variety of technical problems. The financial community has been following these developments closely to learn as much as possible about the "state of the art". On the technical side, we see drilling and production posing little difficulty, though directional drilling in highly fractured zones is a challenging exercise and concern remains about the reliability of downhole pumps. Fluid handling remains a key problem. Corrosion, precipitation and scaling are major problems and the more difficult fluids found in the Salton Sea area have yet to be taken on. The expected efficiency and performance of various conversion systems (binary, single/double flash as well as direct contact) have not been rigorously demonstrated by these two plants and still need confirmation. Finally, injection must be more successfully accomplished. Maximizing field performance, disposing of spent fluids and preventing potential subsidence all depend upon reinjection.

This brings me to the other half of the geothermal equation: the resource. On the one hand, we have much more information about geothermal resources than power plants due to the 200 or so wells which have been drilled outside The Geysers since 1975. This has given us a much better idea of where these resources are and what their potential is. Nevertheless, such information does little to ease a lender's concern about either potential production problems like those encountered on the Baca project or the risk of premature reservoir depletion. Similarly, we feel the production data from the Brawley and East Mesa fields does not have a direct bearing on how other geothermal systems will behave, even in the Imperial Valley.

Indeed, long-term production data from these operations will only have an indirect benefit on the overall development of geothermal energy. This will come about by increasing our confidence in techniques to predict reservoir performance. However, until our confidence in such techniques is increased dramatically, only multi-year production data will induce a lender to assume reservoir risk. In the meantime, we continue to view each project as somewhat of a "demonstration project".

Fortunately, there may be a least one potential short-term solution to this specific problem: reservoir insurance. Insurance companies are financial institutions who are in the business of taking on risks like these. They can provide insurance both against losses arising out of project termination due to resources inadequacy, as well as losses resulting from premature reservoir depletion. The cost of such insurance is not exceptionally high, but neither is the comfort provided by present policies. Nevertheless, I expect such insurance will become a more important part of geothermal financing, especially given today's high rates of inflation and interest which make the potential benefits from expediting geothermal development worth the cost of the insurance.

There are two other aspects of geothermal development going through a phase analogous to demonstration. These are the tax treatment for geothermal development and the PURPA regulations. Over the last few years, Congress has enacted these incentives for geothermal development, but implementation is another matter. For example, the IRS is using its own definition on the activities/assets eligible for the Alternative Energy Tax Credit and PURPA is being challenged in the courts. Hence, the uncertainity created by these matters impairs the ability of the industry to raise the necessary capital to finance geothermal development.

In closing, I would like to indicate that I see limited validity to the life cycle concept for geothermal energy. My concern does not arise due to questions about the hardware and systems for exploitation of geothermal resources. Here the technology can be shown to be feasible, demonstrated, and if practical, commercialized. My problems with this concept is on the resource side of the equation. With the substantial differences from reservoir to reservoir, each new resource will have to demonstrate its adequacy over an extended period of time before it can be considered to be fully commercial like The Geysers. This is not to say that the subsequent power plants on the same resource will each need to be viewed as a new project, but that the performance of one field will tell us little about how we can expect another field to perform. Gradually this concern will be reduced as we become more confident in reservoir prediction techniques, but in the meantime each geothermal project and its technology/resource matrix must be individually evaluated.

EXPLORATION, THE ECONOMIC STRATEGIES

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

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

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

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

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

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

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

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

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

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

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

TABLE I

JOBS RELATED TO EXPLORATION PROGRAM

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

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

TABLE II

EXPLORATION TECHNIQUES AND APPROXIMATE COSTS

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

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

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

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

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

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

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

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

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

TABLE III

50MW HOT WATER FLASH

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

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

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

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

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

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

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

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

TABLE IV

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

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

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

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

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

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

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

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

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

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

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

TABLE V

SUMMARY OF ANNUAL CASH FLOW

110 MV, STEAM PRICE 27.76 MILS/KWH

($000)

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

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WORKSHOP REPORT

NEED FOR DEMONSTRATION OF SPECIFIC TECHNOLOGIES

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

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

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

WORKSHOP REPORT

ROLE OF DEMONSTRATIONS IN RESERVOIR ASSESSMENT AND EVALUATING DIFFERENT RESOURCE TYPES

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At Workshop Session 7B, the participants discussed the definition of demonstration as it affects resource developers: Does a developer obtain any benefit from a demonstration or should a demonstration plant just be considered Unit 1 of the regular field development? A contrast was drawn between a pilot plant, whose data is open only to the company sponsoring the plant, and a demonstration project, whose data is open to the public at large. The decision makers who matter to the resource developer are those who can pay for the plant or plants that produce revenue for the field developer. To the developer, the most crucial parameter is the time interval Δt between the time when the developer is satisfied the resource can be sold and the time when the developer is receiving a return on the investment.

A number of points of view were expressed by participants in the workshop discussion. Nearly all addressed the problem of decreasing the time interval between investment and revenue. Views expressed included the following:

- Information versus Testing Time A smaller size plant, operated at an earlier time, will enable the resource developer to have more information to use in selling the resource than would be obtained from short intermittent tests over the longer period it would have taken to build an initial full-size plant.

- Decision Making When do we know enough about the reservoir? An early decision can be made regarding the capability of the reservoir to support the first unit, somewhere in the 10 to 50 MWe size range. Prolonged data gathering won't add much for the first unit decision. Experience in connection with operation of the first unit, be it "pilot plant" or "demonstration" or whatever, can be valuable for estimating ultimate reservoir capacity and for making decisions on additional units. Thus, a demonstration plant should be viewed primarily as a way to obtain power production early and to provide data for decisions on field capacity and subsequent units.

- Time Lapse before Return on Investment The value of a demonstration to a resource developer is measured by the extent to which it reduces the time between investment in field development and revenue from sales of electricity.

- Size of Initial Plant About 10 MW is required for a useful demonstration: 3 or 4 MW per well for hope of economic success and 3 wells to properly test the reservoir. It is better to get this sooner from a demonstration or pilot plant than to go on testing wells indefinitely while trying to sell a 50 MW project.

- Verification of Predictive Simulators For reservoir analysis, a demonstration has value to the extent that it provides a way to test and improve simulation models that must perform the task of predicting long term behavior of the reservoir from tests that last only a week or a month or so.

- Supply Guarantee versus Full Disclosure A full disclosure of reservoir data, such as would result from a "demonstration" rather than a "pilot plant," is needed if the reservoir risk is to be shared by the utility and its regulatory agencies. If the developer is willing to provide a contractural, financial guarantee of fluid supply and replacement electricity, then only the developer needs the information to make the go-ahead decision and the supply guarantee can substitute for full disclosure. However, if the risk is to be shared by the utility, then the reservoir information must be acceptable to the utility and its financing and regulatory authorities. In this latter situation, the utility must assess security (i.e., reliability of supply) and cost. Acceptable cost is also an issue to be decided by a public utilities commission. Information from a demonstration must match the needs of the decision maker. The decision making process must be open enough for the demonstration to be planned properly, so it meets the needs of the decision makers.

- Pragmatic Size Development The realities of the need to produce some revenue, combined with the need to gain information and operating experience sooner rather than later, lead to a pragmatic size of plant that may be smaller than the economic size.

- Steam versus Electricity A developer can take the initiative in decreasing the time between investment and revenue by investing more and building the power plant himself and selling electricity rather than steam. This appeared to be a tough decision for a developer to make.

- Demonstrations versus Pilot Plants As mentioned above, a pilot plant, with information held proprietary to the owner(s), is an alternative to a demonstration if the decision maker for the subsequent power generating units is simply the owner of the pilot plant.

- Professionalism "Gut feeling" or professional judgment is still likely to determine the estimates put forth by different reservoir engineers. The Wairakei field in New Zealand has been analyzed by at least three different groups of reservoir engineers with three different predictions arising from the same data. After 30 years, there are still surprises emerging from the experience at Wairakei.

To summarize, the question of how demonstrations relate to the resource developer side of the industry hinged around the goal of shortening the time between investment and revenue (i.e., the time between developer commitment and power plant production). Shortening this time will require the following measures, if the "demonstration" rather than the "pilot plant" approach is taken:

- Open access to data and analysis for checking and cross checking by other participants: utilities, insurance companies, banks, etc.

- Enough open access to the decision making process (through a combination of field developer and utility) considered as a process for making a prudent business decision.

- Sufficient visibility to the public (i.e., PUC's and other regulatory bodies) regarding how decisions were made.

- A clear basis for expansion to the next steps of developing and utilizing the field.

The conclusion appeared to be that there is a key role for "demonstration" plants to play in the developement of geothermal fields.

*Don Harban of Phillips Geothermal Company was Chairman of the workshop session. Paul Kruger of Stanford University presented the workshop results to the plenary session. Evan Hughes of EPRI prepared this written summary using notes by Paul Kruger.

WORKSHOP REPORT

POTENTIAL FOR RESOLVING ENVIRONMENTAL AND REGULATORY ISSUES THROUGH DEMONSTRATIONS

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The 15 participants at the workshop included representation from countries other than the United States allowing an interchange on an international basis. The absence of regulatory agencies precluded the benefit of their perspectives. For balance the environmental issues do need review from the perspectives of the:

- producer,
- operator,
- regulator.

In general the panel concurred in the value of demonstrations to provide full scale experience necessary to resolve preliminary environmental concerns or identify issues needing further resolution. There was some differences in opinion as to the size needed for a demonstration. A basic guideline was suggested which recommended the size reflect full-scale operation of the components being tested.

Transferability of the experiences between regions (counties, states, countries) for application was recognized as desirable but questioned as to its ability to satisfy the regulators. This pointed out that site-specific needs cannot be ignored or under-estimated. Examples were given of differences in attitudes between counties and states.

The representative from Japan indicated the need for large demonstrations to properly evaluate the economics and true effects of geothermal development on the environment. While esthetics have received less notice in these early stages of development, Japan is facing the need to utilize geothermal resources in National Parks, where esthetics will be a prime issue.

In recognition of the esthetic issue consideration is being given to semi-underground designs, equipment height reductions, landscaping and smaller plant areas. (5-7 hectares).

There was universal agreement that regulatory agencies should recognize that resolution of environmental concerns will be an ongoing process of the operating unit and make allowances to permit development to proceed with subsequent resolution of the problem.

Mexico's experience supports the benefits to be gained by the balanced decisions of the regulators to allow demonstrations to focus on problem areas for subsequent resolution.

Concern was expressed about the apparent overemphasis on seismic design requirements particularly the repetition in application after application. In view of the potential risk to the public it was felt the seismic requirements are excessive.

Finally, demonstrations provide invaluable assistance to KGRA development from the environmental perspective, provided the demonstration has a sound pre-operational environmental data baseline and a post-operational monitoring program to validate preliminary environmental hypotheses.

REGULATION SUMMARY

There is a general consensus that the Regulatory Agencies and their regulations have a significant influence in the selection of geothermal demonstration plant size and location. Also this influence has generally had a more negative connotation, although there are specific instances where this is not the case.

It is a matter of record that some authorities have encouraged stricter limitation after applied technologies have made significant reductions in H_2S emissions. On the other hand the Imperial County example of informed and intelligent preparation for the development of a new resource, indicates that development can proceed without excessive delay and at the same time protect valid socioeconomic and environmental concerns of the community.

Willingness of the regulatory body to recognize the need for balance between conflicting desires is also apparent in Mexico's example at Cerro Prieto and the growth of that country's geothermal power sources.

It is also recognized that demonstration plants do provide Regulators the feedback of concrete field experience to permit them to fine-tune their regulations so they can be both protective and productive. It remains to be seen if the Agencies will wisely use the experiences for full community welfare.

Geothermal development continues to face unknown regulation exposures. Interested parties will need to follow regulatory development in these areas:

- Underground injection (presently on a two-year deferrment)
- Waste disposal: Federal Resource Conservation and Recovery Act (RCRA) regulations and for states like California with more restrictive in-lieu programs.
- Water discharges: constantly increasing number of chemical and water quality limitations.
- Toxic Substances Control Act
- Comprehensive Environmental Response, Compensation and Liability Act of 1980 (Superfund)
- Air Quality regulations
- Noise

It is vital that demonstration or other field experiences receive dissemination and consideration by the Regulatory bodies if the ensuring regulations are to be useful and beneficial.

GEOTHERMAL POWER DEVELOPMENT IN THE PHILIPPINES

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ABSTRACT

Large scale geothermal energy for electric power generation was put into operation with the inauguration of two 55-MW geothermal generating units at Tiwi, Albay in Southern Luzon in 1979. Another two 55-MW units were added to the Luzon Grid in the same year from Makiling-Banahaw field about 70 kilometers south of Manila. For that year alone, therefore, 220-MW of generating capacity was added to the power supply coming from geothermal energy. Last year a total of 220-MW power was added from the same areas. This brought to 446-MW of installed generating capacity from geothermal energy with 3-MW contributed by the Tongonan Geothermal pilot plant in Tongonan, Leyte, Central Philippines and another 3-MW from Palimpinon-Dauin field in Southern Negros in operation since 1977 and 1980, respectively.

To realize the benefits that stem from the utilization of indigenous geothermal resources and in the light of the country's ever increasing electric power demand and in the absence of large commercial oil discovery in the Philippines, geothermal energy resource development has been accelerated anew. The program includes development of six fields by 1985 by adding Manito and Daklan fields to the currently developed and producing geothermal areas.

INTRODUCTION

In the decade that was the seventies, perhaps no single event of international economic import could compare with the energy crisis of 1973. It affected developed and developing countries alike and clearly showed the fallacy of overdependence on foreign sources of energy. For the Philippines, it provided one of the more severe tests in recent times of the nation's economic and political resilience.

The crisis of 1973 poised great difficulties to the Philippine economy and with further increases in the price of imported oil coupled with uncertainties in the prospects of future supply, the nation was indeed faced in the ensuing years with the spectre of economic strangulation. Thanks, however, to wise planning backed by promulgation of necessary measures and their rapid implementation with an unwavering decisiveness, the country has weathered the energy crisis.

The strategy taken was simple and direct. President Ferdinand E. Marcos enunciated a power development program aimed at attaining self-reliance through availment of indigenous energy resources. He called for an intensive search for alternative sources of energy, the acceleration of oil and coal-exploration work and a dedicated effort to conserve energy. That this strategy has worked can not be denied.

HISTORICAL DEVELOPMENT

Geothermal studies in the Philippines were initiated in 1962 by the Commission on Volcanology, a research agency of the Philippine Government. With research funds made available by the National Science Development Board, the agency undertook geoscientific investigations of the Tiwi, Albay geothermal area. In house expertise, with occasional advice from visiting foreign scientists and with the Bureau of Mines helping out in the drilling of thermal gradient holes was largely relied on to carry out the research project.

Five years later, on April 12, 1967, for the first time in the country, an electric bulb was lighted by geothermal energy at Cale, a remote sleepy barrio in the municipality of Tiwi, Albay Province. The geothermal steam came from a 400-foot one and half inch drillhole and it turned a turbo-generator borrowed from the Mechanical Department of the Mapua Institute of Technology.

Later, with additional research funds, a 641-foot well with a four-inch production liner was bored in 1968 and it produced steam. This enabled the setting up of a 2.5 KW non-condensing geothermal pilot plant for demonstration purposes on what geothermal energy is all about. The well after twelve years is still discharging steam which is also now being used to evaporate sea water in connection with a pilot salt-making plant.

By 1970, the Philippine Government, recognizing the benefits that can be obtained from geothermal energy and realizing that the exploration work at Tiwi had reached the stage for commercial development, gave the National Power Corporation the task to develop and exploit the field. A service contract was entered into in 1971 by the Corporation with Union Oil of California through its subsidiary the Philippine Geothermal, Inc. for the latter to develop the steam field while NPC put up the necessary generating plant. Meanwhile, the Commission on Volcanology was instructed by the Executive Office to transfer its geothermal studies to prospects in Leyte and in the Makiling-Banahaw area of Luzon. Since then, geothermal exploration and drilling activities have been in full swing in these areas.

Thus, it may be said that the support given to a research agency by the government and its early recognition of the potential of geothermal energy as an alternative indigenous energy resource paid off handsomely when the energy crisis came.

FULL STEAM AHEAD FOR GEOTHERMAL

With the flip-over in the economics of petroleum-based electrical power in 1973, a drastic change in the country's power development was imperative. Where before, planning was centered on oil-fired thermal plants providing base load requirements, especially in the provincial service areas, a shift was made so that the main thrust became the availment of hydro, coal and geothermal resources. Since assessment of the Philippines' geothermal power potential is of such magnitude that it can be relied more and more to meet a significant portion of the country's energy requirement, geothermal energy became a major component of the energy program and so the government gave the signal "full steam" for its development.

The Philippines entered into commercial utilization of geothermal energy in July 1977 with operation of a 3-MW geothermal pilot power plant in Tongonan, Leyte. This power plant supplies part of the power needs of Ormoc City. However, it was really only in 1979 that saw the harnessing of large-scale geothermal energy from Tiwi in Albay and Makiling-Banahaw (Mak-Ban) in Laguna. Two 55-megawatt plants were commissioned in each of these areas, adding 220 MW of generating capacity to the Luzon grid and displacing 2.73 million barrels of oil equivalent for 1979.

These were followed almost immediately last year (1980) by an additional two 55-megawatt plants each in Tiwi and Mak-Ban and two 1.5 MW pilot plants in Palimpinon area of Southern Negros thus bringing the total geothermal power generation of the country to an amazing 446 MW by the last quarter of 1980. This means a displacement of slightly over 5.5 million barrels-of-oil equivalent which at oil price levels of $32 per barrel crude would mean a dollar saving of $176 million for 1980.

More geothermal generating units are abuilding or planned in the next five years. Under construction is the first large power plant of three 37.5 MW units to tap the Leyte geothermal resource. This plant is targeted to be commissioned in the last quarter of 1982. A similar 3 x 37.5 MW power plant will soon begin construction in Palimpinon, Southern Negros. This plant planned to be completed in 1983 will supply power to the Negros Island grid and will be further beefed up by a like 112.5 MW geothermal plant in 1985. Additional units are also expected from Tongonan, Tiwi and Mak-Ban, while two new geothermal areas under current exploration, Manito in Albay and Daklan in Benguet, are expected to contribute 165 MW.

By 1985, therefore, the 5-year compressed energy program envisions a whopping 1,718.5 MW contribution from geothermal energy. This amount is to come from only six geothermal fields. Yet there are other geothermal prospects that are already under initial exploratory studies like Biliran, Anahawan, Burawen, Nabunturan, Kidapawan, Montelago, Mabini, Mount Pinatubo and Buguias.

DEVELOPMENT STRATEGIES

If the Philippines has been able to achieve this phenomenal growth in the utilization of her geothermal resources it was perhaps largely due to the unorthodox and bold approach taken in its development. The government opted to take an aggressive stand and put in a little more risk capital to the undertaking than what a conservative orthodox approach would have called for.

Exploration wells were drilled to be production wells so that if successful the time to bring the field into the exploitation stage would be shortened. As soon as two or three producing wells were drilled and pertinent data on steam characteristics obtained, National Power Corporation on advice of the field developer then proceeded to design, bid out, and order the generating units. As much as possible, time-consuming administrative procedures were streamlined and even short-circuited in the interest of rapid development.

The drilling programme was also planned as to complement this bold approach. After a deep well is drilled and it is a steam producer, then subsequent wells were drilled as a cluster around it rather than give priority to delineation wells. This way the decision to put up a power plant came sooner, though, of course, the potential of the field was still just better than a guess. It was a gamble, but perhaps the end justified the means.

GEOTHERMAL POWER PROGRAM

In order to maximize the benefits from the utilization of indigenous geothermal resources, the government's five year program for geothermal exploration and development aims at 1718.5 MW of generating capability by the year 1985 (Table No. 1). The program includes the development of six fields to the currently developed and producing fields at Tiwi, Makiling-Banahaw and Tongonan Valley.

TABLE: 1

PHILIPPINE INSTALLED AND PLANNED GENERATING CAPACITIES, MWe (1977-81)

GEOTHERMAL FIELD	1977	1978	1979	1980	1981	1982	1983	1984	1985	TOTAL
Tongonan	3					75	37.5	110	220	445.5
Tiwi			110	110		110		110	110	550
Mak-Ban			110	110			110			330
Manito									110	110
Daklan									55	55
Palimpinon				3			112.5		112.5	228
Total	3		220	223		185	260	220	607.5	
Cumulative Total	3		223	446		631	891	1111	1718.5	1718.5

POSSIBLE RESEARCH & DEVELOPMENT DIRECTION

The occurrence of numerous hotsprings throughout the Philippines indicates that the country is well endowed with geothermal resources and suggests that all possible methods of utilization of this energy be investigated. Scattered throughout the archipelago are a number of thermal spots that could have geothermal significance.

Research should be directed to accurate evaluation of other potential geothermal areas by correlation with magma generation, structural setting of geothermal fields and association of rock type and mineral alterations. This study should lead to a geothermal reservoir models.

The use of binary system in power generation to utilize low heat subsurface waters should be pursued rigorously. If proven economically viable, this method could find applicability in tapping low-temperature hotsprings in our small island communities.

The utilization of geothermal energy in any form is not without its share of problems. Some of these are environmental problems which should be defined and evaluated in order to insure an environmentally compatible development of geothermal resources. Basically, the possible impact on the environment due to geothermal utilization are, ground subsidence because of extraction of fluid from the subsurface, and chemical-thermal pollution because of disposal and discharge of effluent. The problem of scaling, most often by carbonates or silica, high-acidity of geothermal fluids and the attendant corrosion can be minimized by proper research and development program. These problems are, however, not inherent to all geothermal fields, but are specific only in certain areas in some cases specific only to some steam wells of a particular area.

Hardwares used in geothermal exploration and development are carry overs from the oil industry. Some are therefore found to be insufficient to cope with head pressure and chemical conditions peculiar to geothermal operations.

Geothermal energy is relatively a newcomer in the energy field though earth-heat can be said as old as the earth. Its state of the art has not reached the sophistication of oil and gas technologies.

THE FUTURE OF GEOTHERMAL ENERGY

With further increases in oil and gas prices almost a certainty as the depletion points of their known reserves are approached, the position of geothermal energy compared to fossil fuels improves because it is a renewable form of energy. In the coming decades more and more of the geothermal resources of the world will be developed and exploited, not only for power generation, but for direct applications of the energy as well.

It is indeed a comforting thought that the Philippines has managed within so short a time to be among the foremost users of this indigenous energy resource.

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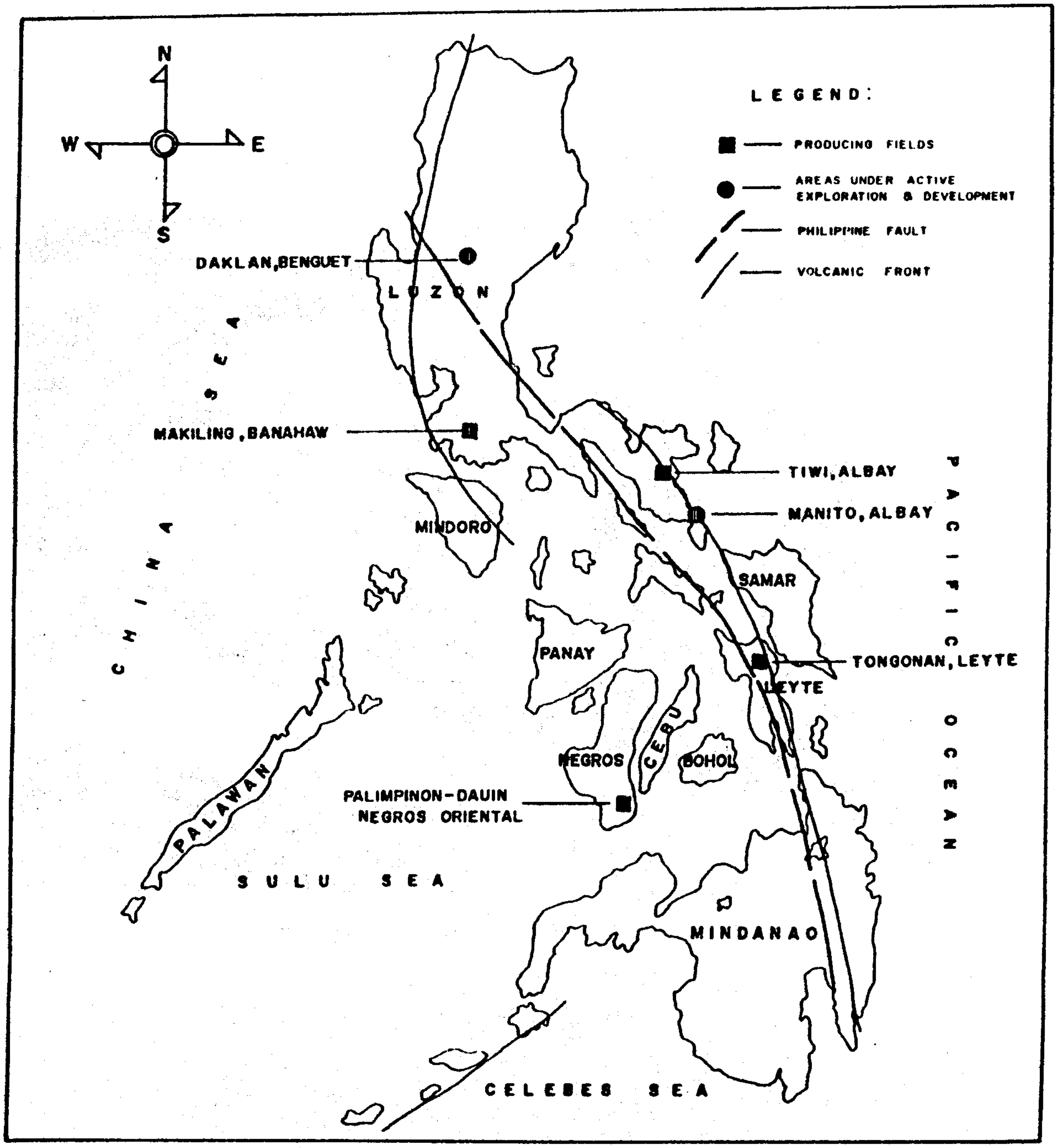
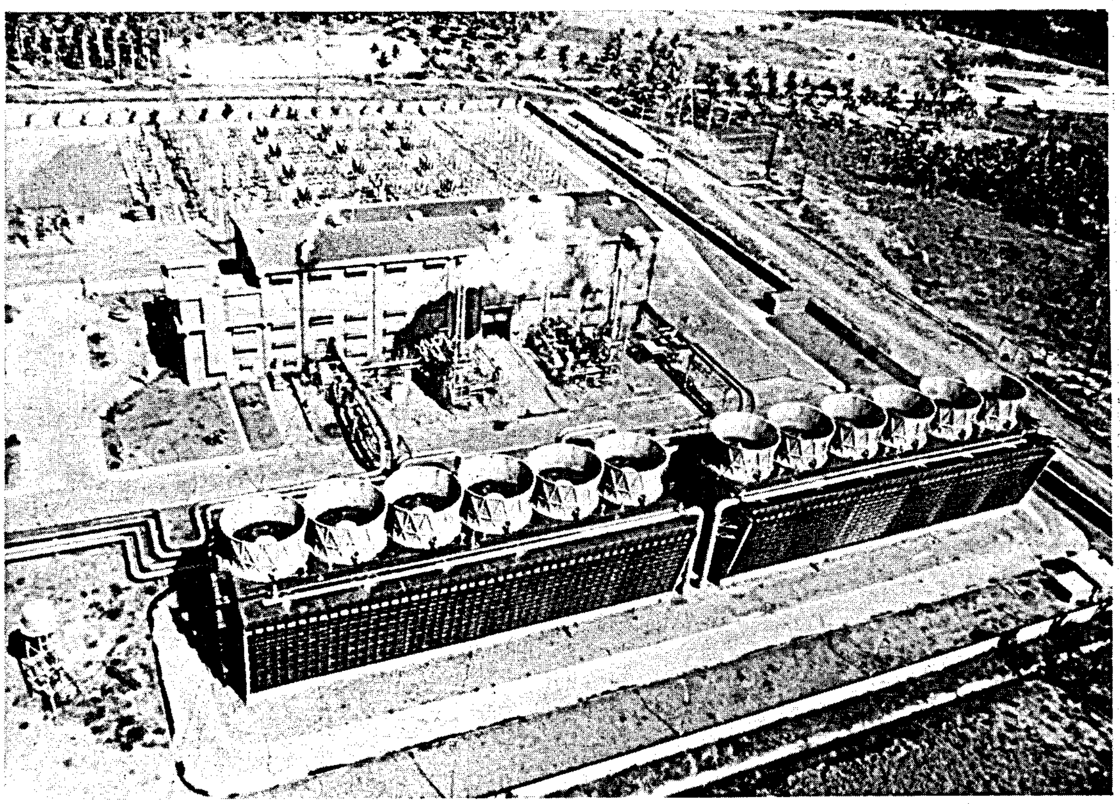
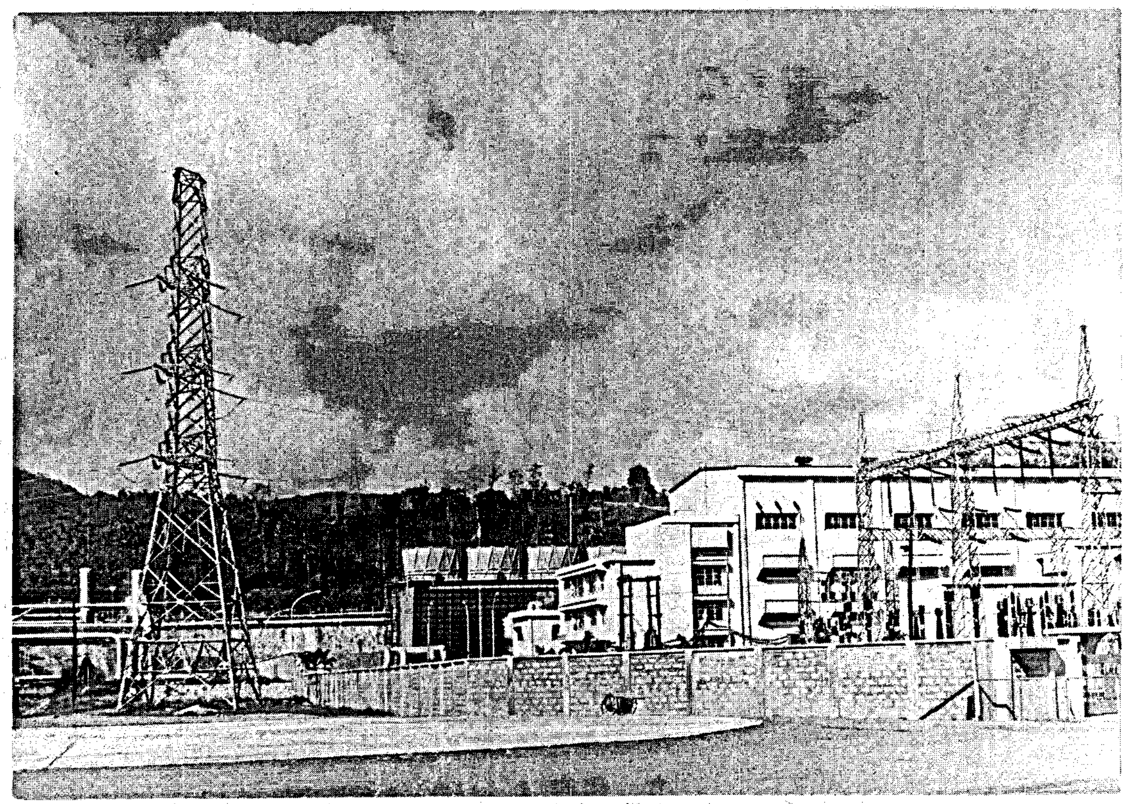


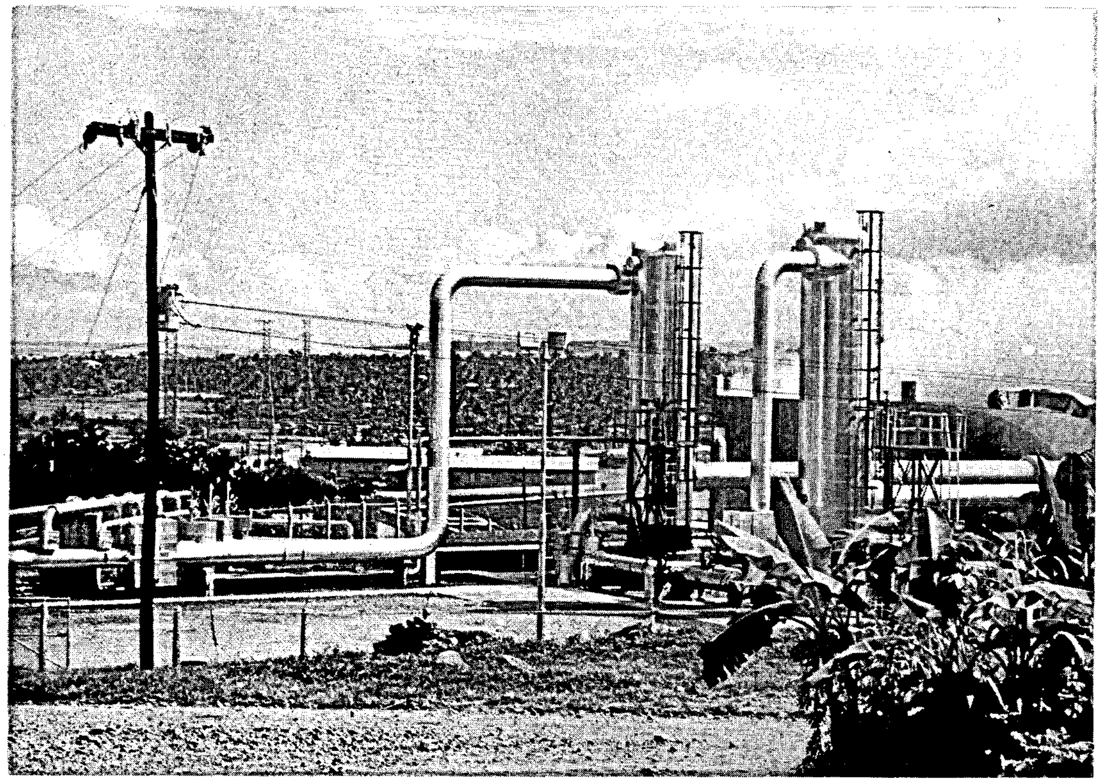
FIG.-I PHILIPPINE GEOTHERMAL AREAS UNDER EXPLORATION AND DEVELOPMENT



Aerial View of Mak-Ban Geothermal Power Plant #1
(Units 1 & 2)



Tiwi Geothermal Power Plant #2 (Units 3 & 4) showing Cooling Tower and Transmission Tower



Sample of Steam/Water Separators used in Tiwi Geothermal Field

STATUS OF GEOTHERMAL ELECTRIC POWER DEVELOPMENT IN MEXICO

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Status of Power Plants On-Line In the State of Baja California, in the Mexicali Valley, the Comisión Federal de Electricidad has in operation a 150000 kW Geothermal Power System, named Cerro Prieto I, that includes a liquid dominated reservoir, production wells, pipeline gathering system, a power plant and an evaporation pond for brine disposal purposes. The power plant has four 37500 kW units in operation. The first unit began commercial operation in April 1973, followed by a second unit in September 1973. Two additional units were placed in operation later in 1979, increasing the plant capacity from 75000 to 150000 kW. From April 1973 to April 1981, these four units have generated 5191 million kWh.

Status of Power Plants Planned and Under Construction In addition to the four Cerro Prieto I operating units, a fifth 30000 kW unit is under construction, and it will begin to operate in July 1981, increasing the total capacity to 180000 kW.

This year will also begin the construction of two geothermal power plants with a generating capacity of 220000 kW each. These new two plants, Cerro Prieto II and Cerro Prieto III, are scheduled to initiate commercial operation in 1983 and 1984 respectively. With such plants operating on line, the total Cerro Prieto's generation capacity will reach 620000 kW by 1984.

As part of the exploration programs for this year, two deep wells will be drilled 7 kms., north-east from the Cerro Prieto I Power Plant, in order to define the reservoir boundary in this direction. If the results are successful, the proven capacity of the Cerro Prieto Geothermal Reservoir will be increased to a minimum of 1000 MW.

In the central part of México, in Los Azufres Geothermal Field, CFE is planning to install five portable non-condensing turbine generators 5000 kW each, scheduled to begin commercial operation in the first quarter of 1982. Preliminary engineering for the construction of a 55000 kW power plant in this field has begun. The total reservoir capacity has been estimated between 300000 and 600000 kW.

Forecast of Geothermal Generating Capacity for the Year 2000 Important efforts during the last 6 years have been made by Comisión Federal de Electricidad towards the diversification of its energy sources for power generation. In 1979 58000 GWH were generated, from which 17800 GWH were produced by hydroelectric plants, 39200 GWH by fossil fuel plants and 1000 GWH by geothermal power plants. The latter figure represented 1.78% of the total electrical energy generation for 1979. To support México's National Industrial Development Plan, where a yearly increase of 14.2% in power supply is expected, CFE is planning the construction of power plants whose power output should be 550000 GWH per year by the end of the century. From such power generation, 80000 GWH will be produced by hydroelectric plants, 270000 by fossil fuel plants, 140000 by nuclear plants, 40000 by coal power plants and 20000 by geothermal power plants. This latter figure will represent 3.6% of the total power generation. This fact implies the need to install geothermal power plants at a rate of 200 MW per year and consequently, the drilling of nearly 40 production geothermal wells per year once the reconnaissance, prefeasibility and feasibility stages of each project have been accomplished.

Technical Features of the Plants and Resources The 150000 kW Cerro Prieto I Geothermal Power Plant is operated with the separated steam produced by 30 wells. The plant requires a total amount of 1580 metric ton/hr of steam assuming a plant factor of 100%. In order to produce this amount of steam, the total steam and water mixture production should be 5000 metric ton/hr. Turbines of Units 1, 2, 3 and 4 of 37.5 MW capacity each, are single cylinder, double flow, impulse and condensing type. The inlet pressure is 6.3 kg/cm^2 abs, and the exhaust pressure is 0.108 kg/cm^2 abs.

In the actual exploited area, the average reservoir temperature is 290°C, the brine's dissolved solids before flashing are 15000 mg/kg. The gas content in the separated steam is 1.7%.

Unit No. 5 will be driven by low pressure steam obtained from two additional flashed stages of the brine, that at the present is discharged to the evaporation pond. The turbine is single-cylinder, double-flow, mixed pressure and condensing type. The steam required to operate this turbine will be 143 metric ton/hr at 4.3 kg/cm^2 abs and 136.4 metric ton/hr at 2.1 kg/cm^2 abs. To obtain this amount of steam 3200 metric ton/hr of brine are required.

The Cerro Prieto II and Cerro Prieto III Power Plants under construction will be supplied with the steam produced by 50 wells. Each plant will consist of two 110000 KW units. Each generator will be operated by two 55000 kW tandem compound turbines, double-flow, mixed pressure, condensing type.

The turbines of the five portable units that will be installed in Los Azufres Geothermal Field are single-cylinder, non-condensing type; the inlet pressure will be 10.2 kg/cm^2. Each plant will be operated with approximately 70 metric ton/hr of steam.

In Los Azufres Geothermal Field, steam and water mixture is produced in some wells, and in others only dry steam is produced. The average reservoir temperature is 300°C and the total dissolved solids are 6400 mg/kg at atmospheric pressure.

Constraints on Development At present the main technical obstacle for the geothermal energy development in Mexico is the difficulty to evaluate the total potential of geothermal reservoirs, that leads to the adoption of conservative evaluation methods in the selection of power plant sizes.

Some other problems that require additional research are those regarding well completion in high temperature reservoirs, associated to cement degradation and casing corrosion problems.

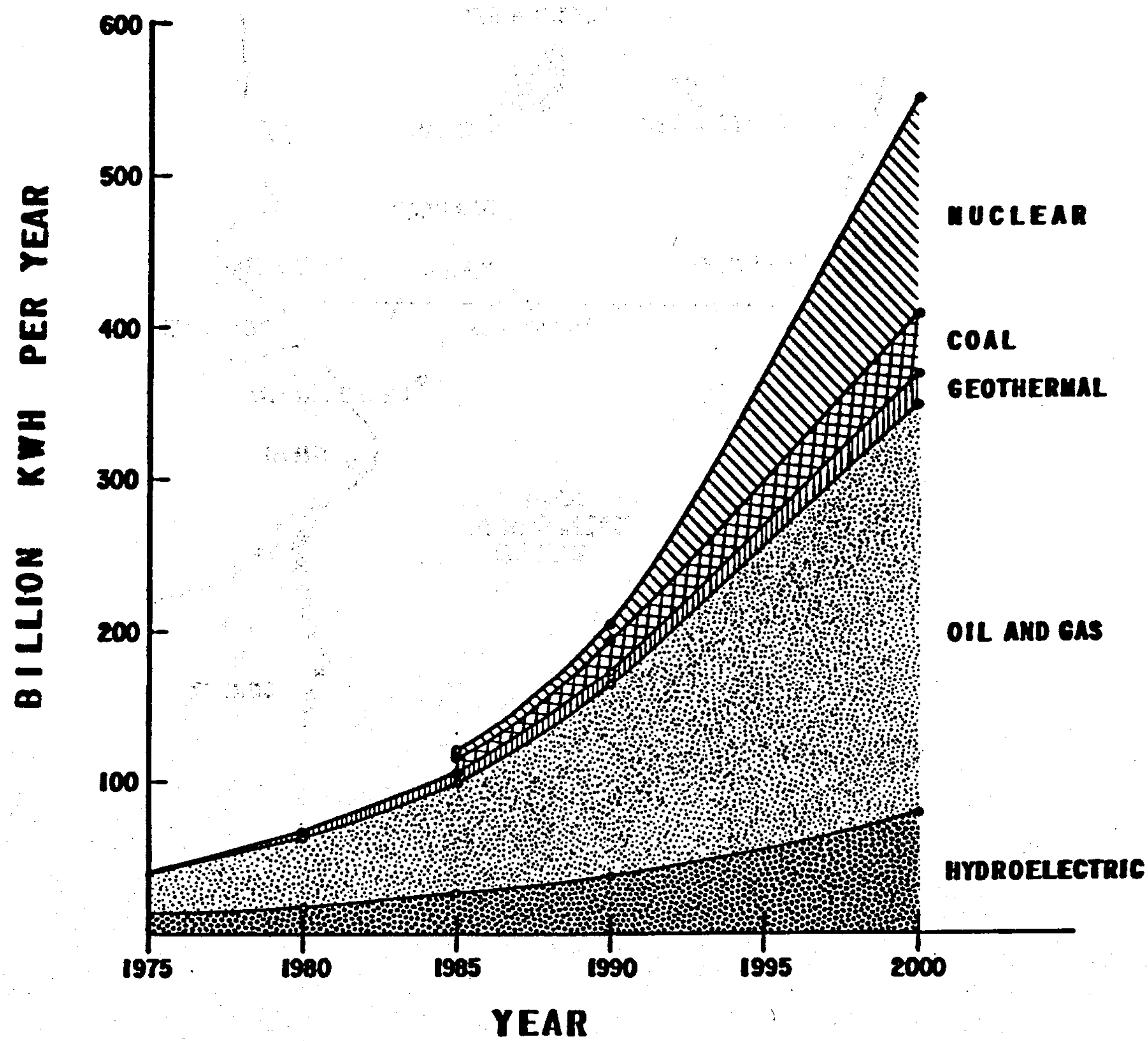
Another potential constraint for Mexico's geothermal development could be the environmental impact caused by geothermal fluids in liquid dominated reservoirs. The general recommended solution in these cases seems to be brine reinjection. Regarding the environmental impact originated by hydrogen sulphide discharge to the atmosphere, though problems have not yet been presented that could stop the geothermal development, some studies and surveys are conducted in Cerro Prieto, using dispersion models and direct measurements of H_2S, to estimate the level of this gas at the atmosphere when new geothermal plants begin to operate. The possible process that could be used to reduce H_2S discharge is also studied.

Another problem that must be studied and solved to facilitate Mexico's geothermal development, is that related to the land extension required for well drilling, above all, when these wells are located in agricultural zones. A potential solution to this problem is to improve the directional drilling technology for geothermal wells.

Finally, it is necessary to train the human resources that will be capable to cover the different stages of exploration, evaluation, project engineering, construction and operation of geothermal power systems that will allow to reach the goal of 4 million kW and so generate 20 thousand million kWH annually towards the end of the century.

ELECTRICAL GENERATION FORECAST

BY TYPE OF SOURCE IN MEXICO



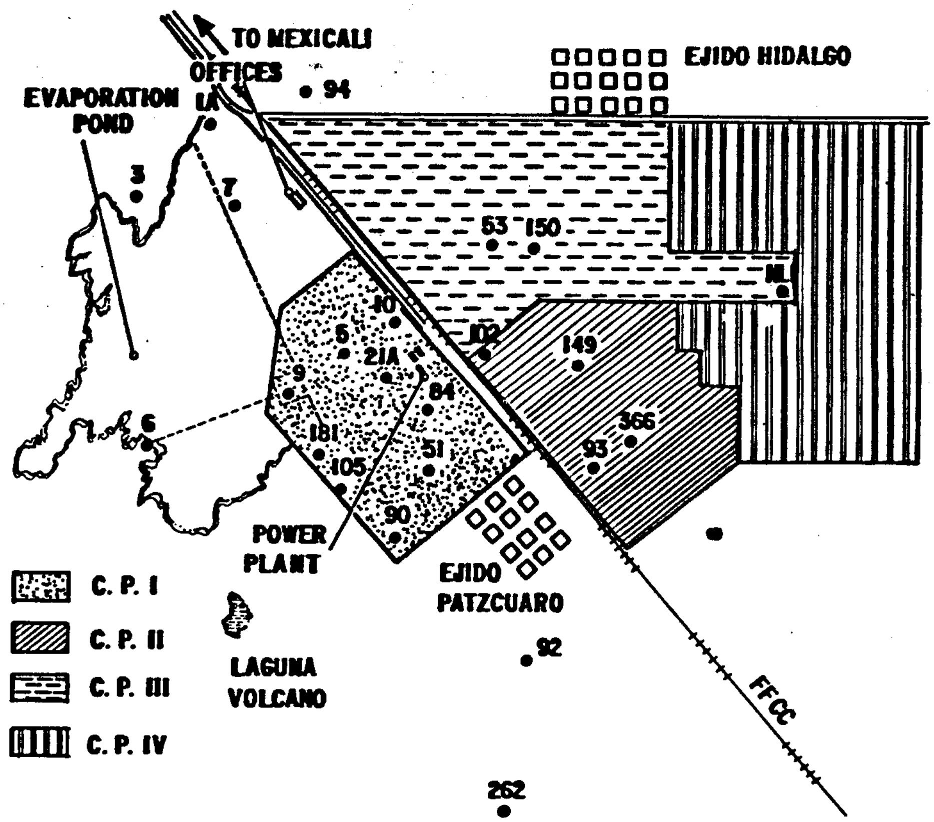
GEOTHERMAL RESOURCE AREAS

STATUS OF GEOTHERMAL POWER PLANTS IN MEXICO

NAME	DATE OF INITIAL OPERATION	CAPACITY MW	STATUS (16-JUNE-81)
PATHE, Hgo.	Nov. 1959	3.5	OUT OF LINE
U1 CERRO PRIETO I	Oct. 1973	37.5	ON LINE
U2 CERRO PRIETO I	May. 1973	37.5	ON LINE
U3 CERRO PRIETO I	Jan. 1979	37.5	ON LINE
U4 CERRO PRIETO I	Mar. 1979	37.5	ON LINE
U5 CERRO PRIETO I	Jul. 1981	30.0	UNDER TEST TO BEGIN OPERATION
U1 CERRO PRIETO II	May. 1983	110.0	UNDER CONSTRUCTION
U2 CERRO PRIETO II	Sep. 1983	110.0	UNDER CONSTRUCTION
U1 CERRO PRIETO III	Jan. 1984	110.0	UNDER CONSTRUCTION
U2 CERRO PRIETO III	May. 1984	110.0	UNDER CONSTRUCTION
5 PORTABLE UNITS LOS AZUFRES	Jul. 1982	25.0	UNDER CONSTRUCTION
U1 LOS AZUFRES	Apr. 1984	55.0	UNDER PROJECT
U2 LOS AZUFRES	Feb. 1987	55.0	UNDER PROJECT
U3 LOS AZUFRES	Dec. 1988	55.0	UNDER PROJECT

NOTE.– THIS PROGRAM DOES NOT INCLUDE ALL THE GEOTHERMAL PROJECTS BUT ONLY THOSE APPROVED BY C.F.E. TO DATE.

CERRO PRIETO GEOTHERMAL DEVELOPMENT AREAS



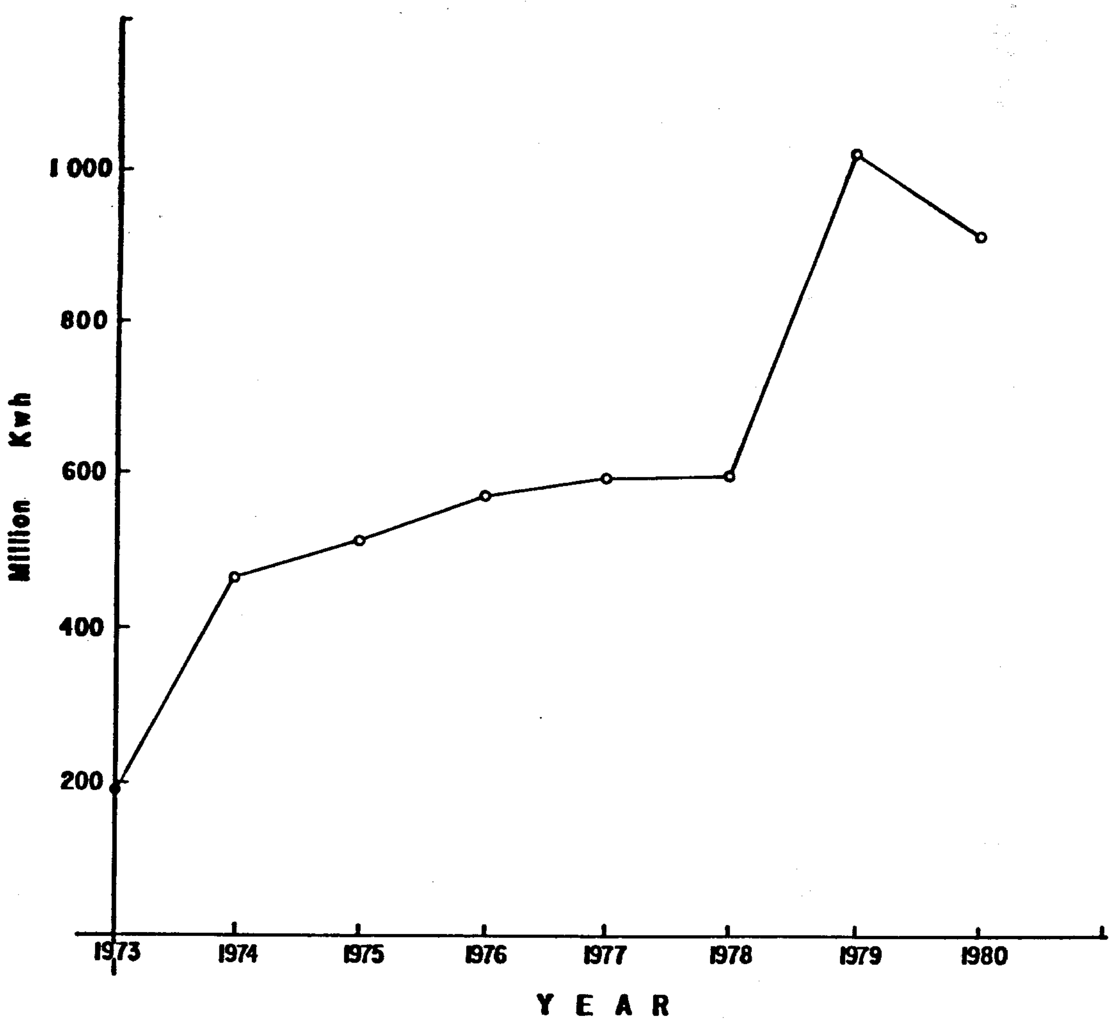
AREA	NO. OF WELLS	M w/WELL	M w.
I	30	6	180
II	25	8.8	220
III	25	8.8	220
IV	40	7.6	380

CFE
VI/81

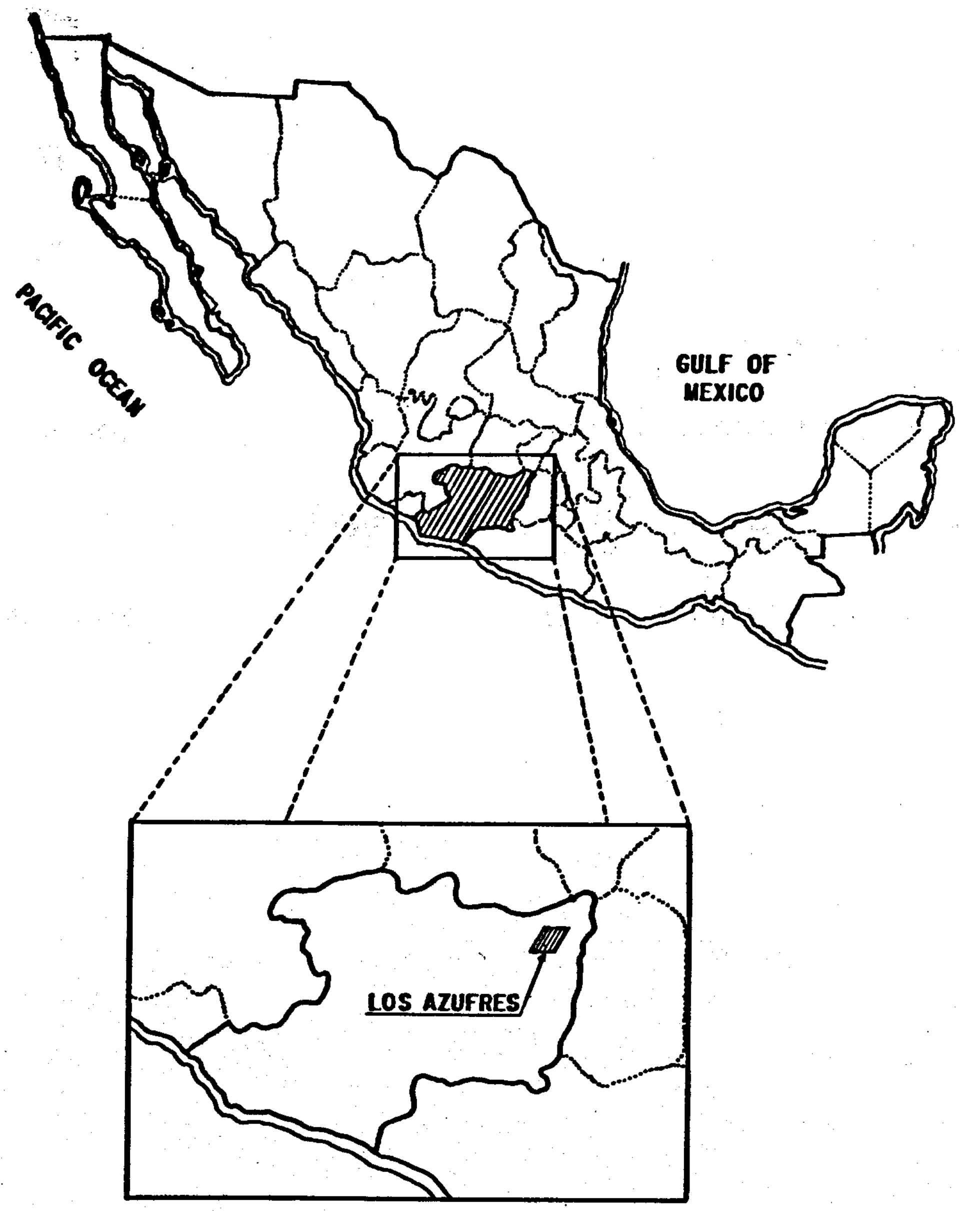
ELECTRICAL GENERATION IN THE CERRO PRIETO GEOTHERMAL PLANT

YEAR	GWH	CAPACITY	PLANT FACTOR
1973	193	75 MW	0.63
1974	463	75 MW	0.70
1975	518	75 MW	0.79
1976	579	75 MW	0.88
1977	592	75 MW	0.90
1978	598	75 MW	0.91
1979	1018	150 MW	0.82
1980	915	150 MW	0.72
TOTAL	4876		

ELECTRICAL GENERATION IN THE CERRO PRIETO I GEOTHERMAL PLANT



LOS AZUFRES GEOTHERMAL AREA



TECHNICAL DATA OF LOS AZUFRES GEOTHERMAL FIELD (Sept. 1981)

DRILLED WELLS	17
PRODUCTIVE WELLS	12
INJECTION WELLS	4
PRODUCTION DEPTH RANGE	600-1500 m.
AVERAGE STEAM PRODUCTION PER WELL	64.5 METRIC TONS./Hr.
RESERVOIR TEMPERATURE	250-300 °C

DEVELOPMENT OF GEOTHERMAL ENERGY FOR ELECTRICITY GENERATION IN ITALY

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1. Background

The exploitation of geothermal energy to generate electricity can be said to have begun in Italy in 1904 when about 15 kW were generated to illuminate the plants producing boric acid at Larderello. However, the first geothermoelectric power station began operating in 1913, with a capacity of 250 kW. From that moment on continuous research, drillings, new plants, and improved technology have, despite the halt enforced by the war years, led to the present installed capacity of 439,600 MW in the Larderello, Travale, and Mt. Amiata areas. These are, in fact, the only vapour-dominated geothermal fields that have been discovered so far in Italy.

2. Geothermal Fluid

The power stations operating nowadays are fed by about 200 wells spread over an immense area within the Larderello, Travale, and Mt. Amiata regions.

Each of these wells produces a fluid comprising for the most part steam and other constituents, the most predominant of which is CO_2 (see Fig.1).

These constituents often have a major influence on the choice of utilization plant; the content of uncondensable gases affects the choice of materials used and the decision to expand at less than atmospheric pressure or not.

Usually no serious corrosion problems arise when natural steam is superheated where there is no condensate phase, so that a carbon steel can be used satisfactorily. However, the fluid in some of the wells at Larderello contains rather abundant traces of the chlorine ion.

The chlorine content is generally below 10 ppm; in some wells it exceeds 50-100 ppm and may also vary suddenly with time.

The chlorine content has been shown to be particularly high in some of the more recently drilled deep wells that produce a high temperature fluid ($\cong 250^oC$). This creates grave problems in transport and in the turbine whenever there is condensate present (insulation failures, on the contact points between pipelines and supports, etc.).

The corrosive properties of the endogenous fluids sometimes take their toll of even the best steels: corrosion has indeed been noted to develop even faster in some inox steels, appearing in the form of pitting.

The most effective means of fighting the chlorine ion would so far seem to be that of "cleaning" the steam with an alkaline solution (NaOH at 1.5%); a slightly higher dose of this solution than is really necessary for complete saturation is added to the steam; the fluid then passes through the separators to eliminate the liquid phase containing the chlorides. This treatment takes place before the steam enters the turbine so that there is obviously some loss in capacity. However, adequate compensation is made for this in the reduction in corrosion phenomena in the machinery.

Endogenous fluid temperature ranges between a minimum of 120-130^oC and a maximum of about 250^oC.

Fluid pressure on entering the power plants ranges from 2 to 11 ata. Well flow rate usually varies from a few tons per hour to about one hundred. The relationship between flow rate and production pressure is expressed by characteristic curves whose trends are shown in Figures 2 and 3. The characteristic curve is not constant with time, as flow rate and pressure both tend to decrease as production proceeds. The pressure and flow rate of each well in the network thus change with time.

Each characteristic curve obviously has a point at which the theoretical extractable capacity is maximum, all other conditions being equal. It would clearly be more economic to operate at this point, but, in practical terms, the operational flow rate and pressure are chosen on the basis of other factors, such as the existing network of steam pipilines, available machinery and also results of reservoir engineering studies.

3. Fluid Transport

The wells feeding the power plants are spread over a surface area of several square kilometres. They are connected to the utilization plants by a network of steam pipelines totalling about 120 km. The pipes, in welded steel, vary in diameter from 150 to 800 mm and are covered externally by a layer of insulating material (asbestos or rock wool) of about 80 mm thickness. A sheet of polyethyline is placed over the insulating material and the lot covered by thin (o.8-1 mm) sheets of aluminum as a final protection.

A double series of safety devices are fitted on the steam pipelines to avoid an excess buildup of pressures within the pipes should there be breakdowns in the utilization plants or erroneous handling of the valves. Automatic pressure control valves are fitted in the power plants and safety diaphragms all along the pipes, calibrated to the nominal pressure of the latter.

The pipes, which were at one time laid with bellows, now follow a zigzag route, so that the variation in length caused by thermal expansion is kept within the elastic deformation limits of the system and passed on to the cambers of each arch of pipeline. The increase in the length of the pipelines is thus negligible. The diameters are chosen so as to strike a happy medium between reduction in load loss and costs. Provision must also be made for the decline in produced fluid with time and an eventual insertion of new wells into the network. The steam velocity in the pipelines at Larderello ranges from 25 to 40 m/s. The average heat dispersion was calculated at 100 $kcal/m^2h$; the overall transmission coefficient ranges between 0.1 and 1 $kcal/m^2h\ ^oC$.

4. Utilization Plants

The choice of plant for generating electricity depends on the chemiophysical characteristics of the fluid and on the set of objectives.

At the moment the endogenous fluid is carried directly into the turbines as the indirect cycle plants have by now been completely abandoned. In these more complicated and expensive systems (Fig. 4), the fluid entering the turbine was a much cleaner steam than the endogenous fluid. Nowadays the materials and technologies are so far advanced as to permit the use of direct cycles.

The cycles used now to generate electricity from endogenous fluids are summarized in Fig. 5. Installed capacity in each unit ranges from about 900 kW to 26,000 kW (Fig. 6). The utilization coefficient of the plants, by which we mean the ratio of operational hours to the total number of hours in a year, is 96.43%. The ratio of energy produced to theoretical attainable energy with the present installed capacity is, on the other hand, much lower, as some units in the Larderello zone are not operating at full load.

In the simplest cycle the steam enters directly into the turbine and discharge is into the atmosphere.

The plant adopting this cycle has a specific consumption of 15-20 kg of endogenous fluid for each kWh. It is very cheap and easy to install. Running and maintenance costs are relatively small.

These plants are installed wherever the condensing plants are not economically feasible, i.e., where the fluid has a high content of un-uncondensable gases.

Plants of this type (1000 and 3500 kW) have also been installed in order to carry out long-term production tests for studying the characteristics of one or a group of wells. The 15,000 kW back-pressure unit operating in the Piancastagnaio plant at Mr. Amiata uses the above-described cycle: it has an impulse and reaction type turbine that permits shuttering of the inlet valves and can operate with a high efficiency at pressures between 5 and 11 ata with up to 20% gas percentage, by means of special bladed rings that can be inserted or removed depending on the fluid conditions of the moment.

The unit can adapt to varying inlet pressures and can, where necessary, be coupled to a second low-pressure unit and to the gas extractor-compressor; the plant can thus be converted to a condensing cycle.

The latter is, in fact, the most common cycle in the geothermoelectric power plants.

All the plants using this cycle (Fig. 7) are fitted with direct contact barometric type condensers and multi-stage gas compressors-extractors with intermediate coolers. The water is carried to the condenser by the difference in pressure while being pumped from the hot tank to the cooling towers. The pumps are usually of the vertical axis type with a submersed helical centrifugal rotor with blades that can vary in tilt to adjust the flow rate when a change of water level is desired.

In the Radicondolo 2 (Travale) and S. Martino power plants the pumps are the vertical axis type with submersed centrifugal rotor and control valve on the delivery side.

The circulation water is usually cooled in reinforced cement cooling towers of natural draught, with a Δt between 10 and 14^oC, as there is not enough cold water available.

In the Radicondoli 2 (Travale) power plant, which has an installed capacity of 30 MW and began service in 1980, the circulation water is cooled in much smaller induced draught towers.

New criteria have recently been adopted in the design of new power plants, as part of a program for amplifying and developing geothermal activity. The new plants will thus be designed and constructed with the following set objectives: speed and economy in construction, economy in running and size, great flexibility and reliability, simplicity.

Work has already begun on three new 8 MW power plants with a direct admission condensing cycle that were based on some of the above, unconventional criteria. The water will no longer be extracted from the condenser by way of a barometric pipe, as in other power plants, but using extraction pumps. Thus less civil engineering work will be required and the plant will be simpler.

In the future the power plants will be constructed very soon after the geothermal fluid is discovered, as highly flexible machinery and equipment (capable of operating in relatively wide ranges of flow rate and pressure) will enable the plants to be ordered before the fluid is even discovered. If kept in store they can be available at very short notice.

The turbine, alternator, condenser and main pump will be installed on the same level, thus eliminating a great deal of civil works; the power plants will be remote-controlled and able to start and stop automatically.

5. Resource Prospects for Electricity Generation

Estimates of the geothermal potential are based on conventional evaluation methodologies that begin by evaluating the total heat stored in the underground to a certain depth and end with an estimate of the conomically extractable quantities, i.e., the so-called "reserves". Estimates made in Italy refer to a depth of 3000 m and are based on methodologies elaborated jointly by ENEL and the DOE (USA).

The thermal energy in the underground down to this depth, throughout Italian territory, is of the order of 2250 x 10^9 TEP; the extractable energy is, however, merely a very small percentage of this figure.

The "reserves" in this country are estimated indeed at around 10 thousand million TEP. Much of this energy, however, cannot be extracted at temperatures above 130°C and, where electricity generation is concerned, would require a technology that has still to be tried and tested.

Where electricity generation is concerned, fluids corresponding to a geothermoelectric potential of about 100 GWa_e are estimated to be extractable from Italian territory, i.e., about 900 thousand million kWh. Assuming that these "reserves" were to be exhausted in a 50-year period, then theoretically 2000 MW_e could be installed.

When setting industrial objectives one must bear in mind factors such as the type of fluids, as this can create problems when utilizing the reserves; the maximum capacity attainable in Italy from the reserves should thus, in practical terms, be estimated at about one thousand MWe for 50 years (Fig. 8).

Note, however, that these reserves are distributed all over the country in a non-uniform fashion; they are concentrated mainly within the pre-Apennine belt of Tuscany, Latium, and Campania, which can be said to contain more than 90% of Italy's entire geothermal resources. Within this belt the most favoured area as far as geothermal energy is concerned are: Larderello, Radicondolo-Travale, and Mt. Amiata in Tuscany; The Volsini and Sabatini Mounts and the Albani Hills in Latium and the Phlegraean and Ischian along with the Vesuvian areas in Campania. The main activity should therefore be concentrated in these areas (Fig. 9.).

Where the Larderello field is concerned, ranking foremost of all the others for the excellent characteristics of its fluids, production is expected to increase with drilling of new wells in the marginal areas and with the reinjection of part of the condensate from the power plants.

Current experiments and studies would appear to confirm that the waters reinjected into the field represent at least a partial recharge to the reservoir.

With regard to the other known, but water-dominated, fields, research and experiments are now being carried out to investigate all possible alternatives for generating electricity. Attempts are also being made to solve the many problems caused by the dissolved salts, such as incrustation, corrosion, depositing, waste disposal, etc.

A demonstration plant will begin operating shortly in the Cesano field, whose fluid consists of water with an extremely high salt content.

Operation of this plant will hopefully provide useful indications for utilizing this type of resource. The Helical Screw Expander, a total flow machine, will be tested in this plant.

Experimental flash steam and binary cycle plants are also planned, to test the technical and economic feasibility of generating electricity from mid- and low-enthalpy fluids.

H_2O	=	955.29 g
CO_2	=	41.85 g
CH_4 and H_2	=	1.10 g
H_2S	=	0.92 g
N_2	=	0.30 g
H_3BO_3	=	0.35 g
NH_3	=	0.19 g
Rare gases	=	1.00 g

When 1 Kg. of fluid is condensated, the volume of gas left uncondensated is equal to around 25 litres; the composition of this gas is:

CO_2 = 92-95%

H_2S = 2-2.5%

The remainder is made up of H_2, CH_4, N_2 and rare gases (residue not absordable with KOH and NaOH)

Fig. 1 - Average composition of 1 Kg of endogenous fluid.

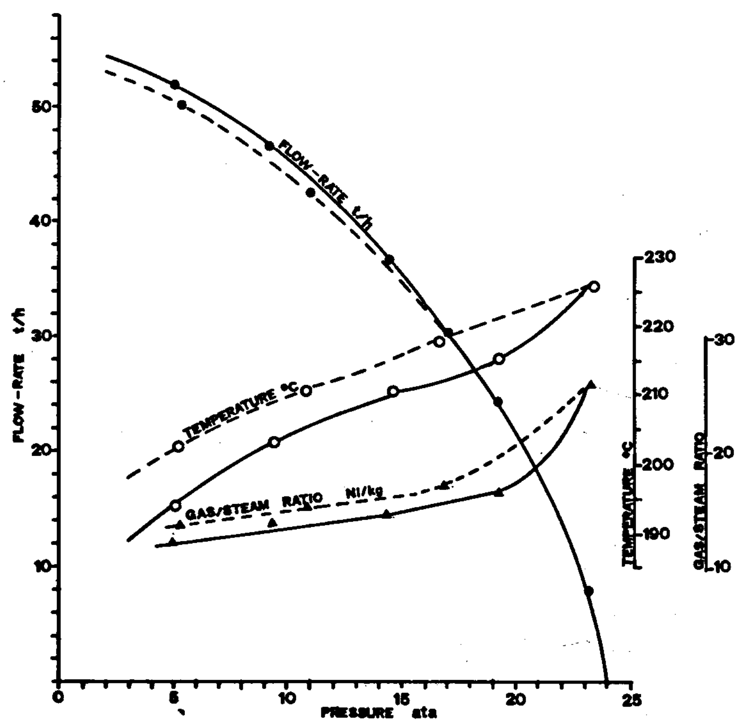

Fig. 2 - Back-pressure curves of a geothermal well

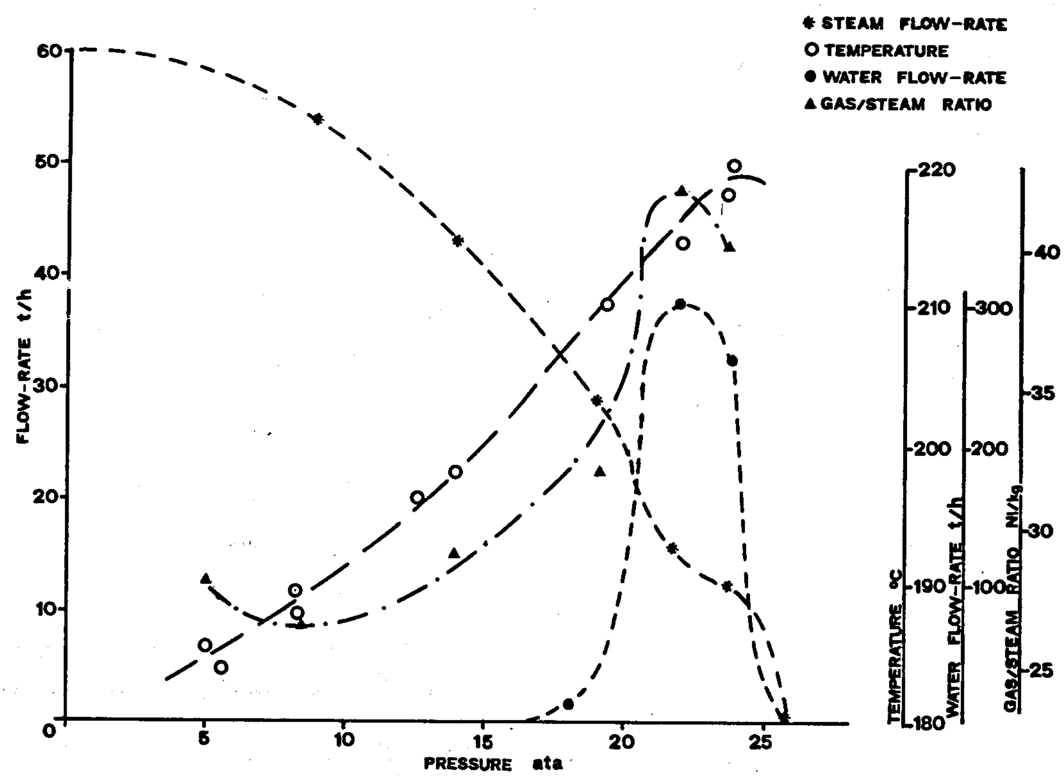

Fig. 3 - Back-pressure curves of a geothermal well

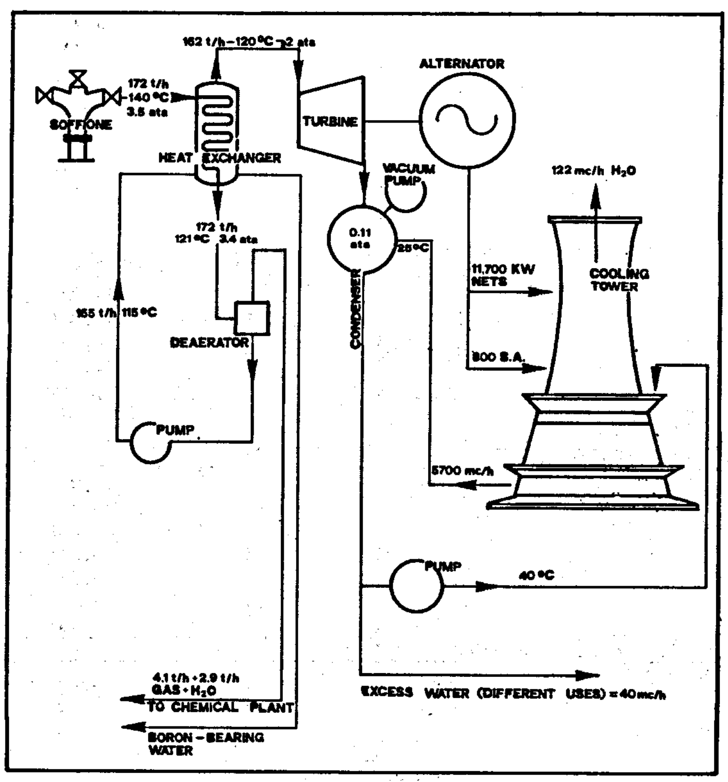

Fig. 4 - Pure condensation steam power (Cycle 2)

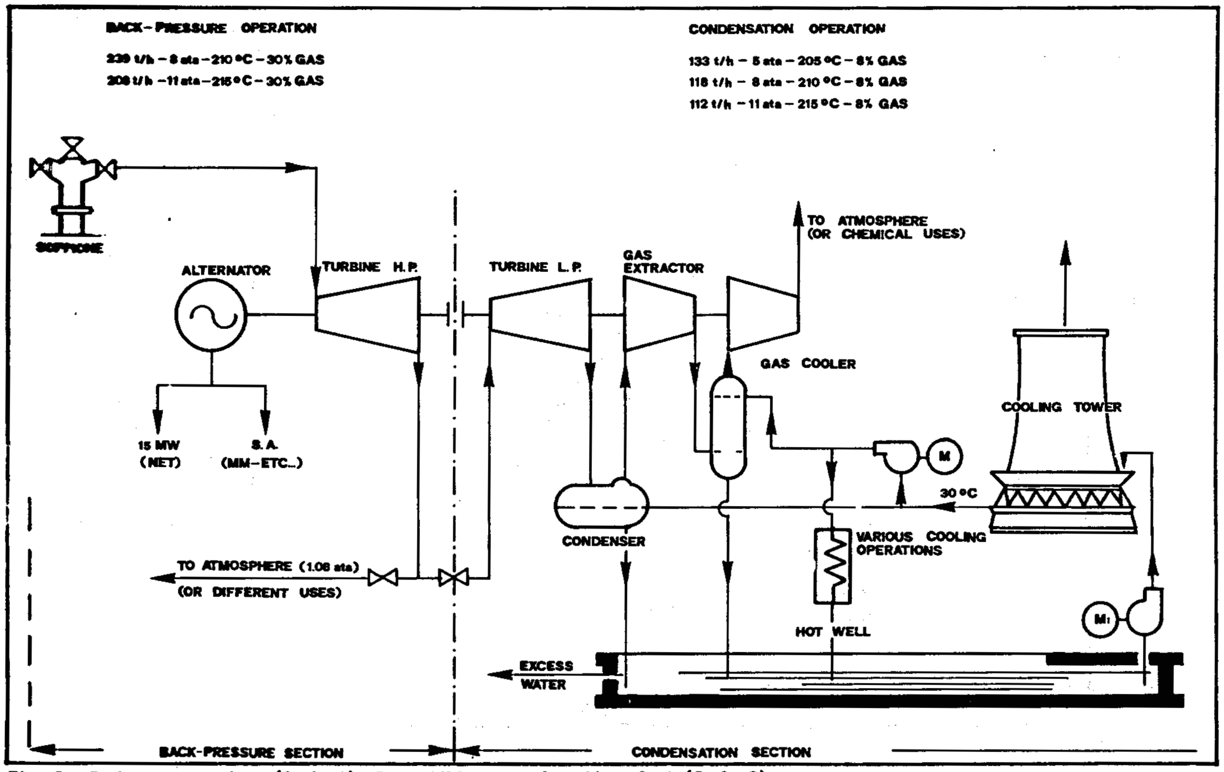

Fig. 5 - Back-pressure plant (Cycle 1). Convertible to condensation plant (Cycle 3)

Power plant	Cycle	Number of units	Capacity per unit	(kW) Total
Larderello 2	3	4	14,500	58,000
Larderello 3	3	3	26,000	
	3	1	24,000	111,000
S. Martino	3	1	9,000	9,000
Gabbro	3	1	15,000	15,000
Castelnuovo V.C.	3	1	26,000	
	3	2	11,000	
	3	1	2,000	50,000
Serrazzano	3	1	15,000	
	3	2	12,500	
	3	2	3,500	47,000
Lago	3	1	14,500	
	3	1	12,500	
	3	1	6,500	33,500
Monterotondo M.mo	3	1	12,500	12,500
Sasso Pisano 2	3	1	12,500	
	3	1	3,200	15,700
Radicondoli 2	3	2	15,000	30,000
Condensing plants in the boraciferous region	3	27	-	381,700
Travale-Radicondoli	1	1	3,000	
	1	1	15,000	18,000
Sasso Pisano 1	1	2	3,500	3,500
Molinetto	1	1	3,500	3,500
Lagoni Rossi 1	1	1	3,500	3,500
Lagoni Rossi 2	1	1	3,000	3,000
Vallonsordo	1	1	900	900
Back-pressure plants in the boraciferous region	1	8	-	35,900
Total plants in the boraciferous region		35		417,600
Bagnore 1 (M. Amiata)	1	1	3,500	3,500
Bagnore 2 (M. Amiata)	1	1	3,500	3,500
Piancastagnaio (M. Amiata)	1	1	15,000	15,000
Back-pressure plants (M. Amiata)	1	3	-	22,000
Grand total: Power plants	-	38	-	439,600

Fig. 6 - Installed capacity of italian geothermoelectric power plants

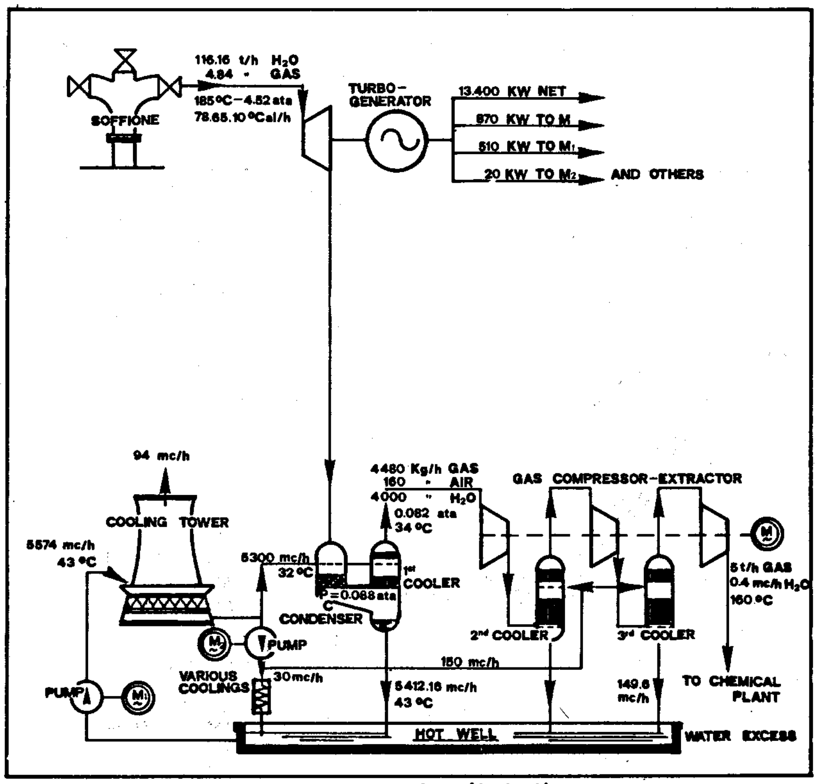

Fig. 7 - Natural condensation steam power plant (Cycle 3)

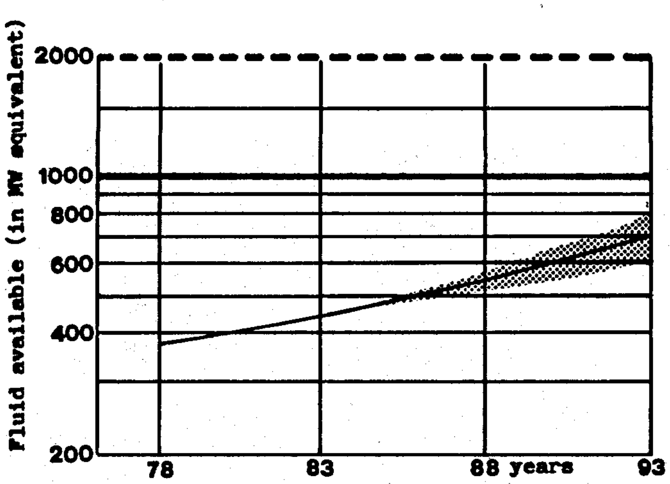

Fig. 8 - Predictions for the availability of geo
thermal resources for electricity gene-
ration.

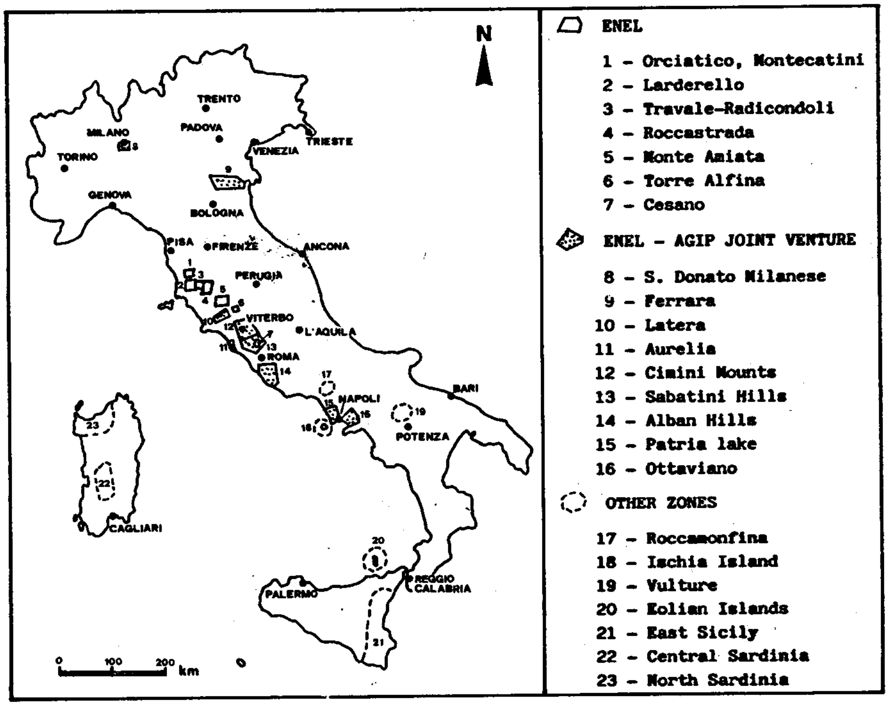

Fig. 9 - Areas of geothermal interest

JAPAN'S GEOTHERMAL POWER DEVELOPMENT

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Abstract Japan is the only one country which has operated geothermal plants of the dry steam, single flash, double flash and binary type.

The total geothermal electric generating capacity is 168 MW as of June, 1981. However more than 10,000 MW is aimed to be put on line by the year 2000.

Japan has more than 200 geothermal areas including 65 volcanoes which promise abundant geothermal energy potential.

However, exploitation of geothermal energy for electric power has been slow in Japan because almost all of the outstanding geothermal prospects are located in national parks, which are protected for their natural beauty.

The construction and operation of geothermal power plants are subject to strict controls.

The full range of geothermal activities in Japan is directed by the government's Ministry of International Trade and Industry (MITI) through the Sunshine Project.

"Development of geothermal energy utilization" started in 1974 by Sunshine Project. This is divided into ① Exploitation Technology, ② Extracting Technology, ③ Material Development, ④ Hot Dry Rocks Power Generation, ⑤ Environment Protection & Multi-Purpose Utilization and ⑥ Hot Water Power Generation, and these are expected to be completed by the year 2000.

(1) Status of Power Plants on Line

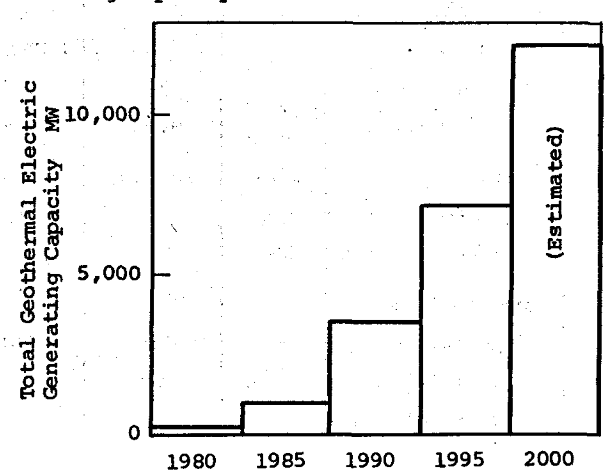
Name of Plant	Rated Output kW	Date of Initial Operation
Japan Metals and Chemicals Co. Matsukawa	20,000	Oct., 1966
Kyushu Electric Power Co. Otake	10,000	Aug., 1967
Mitsubishi Metal Co. Onuma	10,000	Nov., 1973
Electric Power Development Co. Onikobe	25,000	May, 1975
Kyushu Electric Power Co. Hatchobaru	50,000	Jun., 1977
Japan Metals and Chemicals Co. Tohoku Electric Power Co. Kakkonda	50,000	May, 1978
Hotel Suginoi Suginoi	3,000	Mar., 1981
Total	168,000	—

(*) Speaker

(2) Status of Power Plants Planned or under Construction

Name of Plant	Rated Output kW	Date of Initial Operation
Donan Geothermal Energy Co. Hokkaido Electric Power Co. Mori	50,000	Nov., 1981
Total	50,000	—

(3) Forecast of Geothermal Electric Generating Capacity to the Year 2000



(4) Technical Features of the Plants

DATA	UNIT / PLANT	Matsukawa	Otake	Onuma	Onikobe	Hatchobaru	Kakkonda	Suginoi
Plant								
Type	-	Dry Steam	Single Flash	Single Flash	Single Flash	Double Flash	Single Flash	Single Flash
Turbine								
Type	-	SCSF	SCSF	SCSF	SCSF	SCDF	SCDF	SCSF
No. of Stages	-	4	4	4	5	5 x 2	4 x 2	1
Rated Output	kW	20,000	10,000	10,000	25,000	50,000	50,000	3,000
Capability	kW	22,000	13,000	12,500	25,000	55,000	50,000	3,000
Speed	rpm	3,000	3,600	3,000	3,000	3,600	3,000	3,600
Main Steam								
Pressure	kg/cm^2g	3.5	1.5	1.5	3.5	5.5/0.43	4.5	3.0
Temperature	°C	147	127	127	147	161/109	147	143
Gas Content (wt)	%	0.2∿0.6	0.8	0.1	0.5	0.45	0.62	0.5
Exhaust Press.	kg/cm^2 abs.	0.138	0.11	0.11	0.116	0.10	0.138	0.30
Main Steam Flow	T/H	193	113	107	220	312/107	478	40
Last Stage Blade Height	mm (in)	584 (23)	420 (16.5)	500 (19.7)	630 (24.8)	635 (25)	584 (23)	75 (2.95)
Condenser								
Type (a)	-	DCB	DCB	DCB	DCB	DCL	DCL	DCB
Pressure	kg/cm^2 abs.	0.13	0.10	0.10	0.102	0.10	0.138	0.30
Cooling Water Temp.	°C	25	26	23	26	26	25	32
Hot Water Temp.	°C	47.0	41.4	43.4	41.8	43.5	48.8	66.7
Cooling Water Flow	m^3/H	4,320	3,900	2,850	7,062	12,300	10,218	600
Gas Extractor								
Type (b)	-	SJE	MDRVP	MDRVP	SJE	MDRB	SJE	MDVP
No. of Stages	-	2	1	1	2	4	2	1
Suction Press.	kg/cm^2 abs.	0.129	0.092	0.092	0.095	0.095	0.138	0.29
Capacity	m^3/H	18,000	4,620x2	1,050	6,750	20,600	3,840 kg/H	600
Steam Consumption	T/H		-	-	15	-	14.23	-
Power Consumption	kW	-	53 x 2	30	-	315	-	22
Cooling Tower								
Type (c)	-	ND	CXMD	CXMD	CTMD	CTMD	CXMD	Pond
No. of Cells	-	1	3	3	5	4	8	-
Design Wet Bulb Temp.	°C	17	17	14	17	17	17	-
Fan Motor Power	kW	-	66	86		213	110	-

(a) DCB = direct contact barometric type
DCL = direct contact low level type

(b) SJE = steam jet ejector
MDRVP= motor driven reciprocating vacuum pump
MDRB = motor driven radial blower
MDVP = motor driven rotary vacuum pump

(c) ND = natural draft
CXMD = cross flow mechanical draft
CTMD = counterflow mechanical draft

(5) Constraints on Development

1. Geothermal Energy Exploitation Technology

   1. Investigation and verification of geothermal energy exploitation technology

   2. Investigation on exploitation technology of deep geothermal resources

   3. Investigation on making national geothermal resources map

2. Geothermal Energy Extracting Technology

   1. Development of mud water usable under geothermal environment

   2. Development of cement usable under geothermal environment

   3. Development of drilling technology for high temperature stratum

   4. Development of measuring technology in geothermal well

   5. Investigation of hot water reinjection mechanism

3. Development of Materials for Geothermal Energy Utilization

   1. Investigation on development of materials for geothermal energy utilization

4. Hot Dry Rocks Power Generating System

   1. Investigation on drilling and crushing of hot dry rocks

   2. Feasibility study on hot dry rock power generation system

5. Environment Protection Technology Multi-Purpose Utilization Technology

   1. Development of geofluid treatment

      - Hydrogen sulfide scrubbing technology
      - Scale deposition prevention technology

6. Hot Water Power Generation System

   1. Development of two phase total flow rotating expander

   2. Development of hot water power generation plant

7. Development of hot water supply system from deep stratum

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GEOTHERMAL ENERGY IN JAPAN

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Japan's Energy Situation Japan is short of almost every important mineral resource and is entirely or almost entirely dependent on imports. Worst of all, it is almost completely lacking in petroleum, a key energy resource, and this energy source currently accounts for roughly three quarters of total Japanese energy consumption.

Japan's energy consumption is second in the free world following the United States. However, per capita energy consumption is about one-third that of the United States or Canada.

Alternative Energy Development and Targets for Geothermal Development MITI, Ministry of International Trade and Industry, studied both the fundamental problems and issues regarding the establishment of targets for the supply of alternative energy in conformity with the "Law Concerning the promotion of Development and Introduction of Alternative Energy Sources."

As the long-term domestic and international energy situation is difficult to predict, it is necessary for Japan to promptly enhance the development and introduction of alternative energy sources in order to secure a smooth supply of energy. Consequently, Japan should endeavor to satisfy at least 50% of her energy demands by means of alternative energy sources in fiscal year 1990.

With the above figure serving as a major goal, alternative sources of energy and their individual supply targets in FY 1990 were studied. Due consideration was given to each energy source's past performance and supply, as well as the effects of various past and future policy measures, before arriving at the following conclusions. Full cooperation is expected from both the government and private sector in order to fulfill these targets.

Through the enhancement and development of geothermal resources, an annual supply target of 7.3 million kl, the equivalent of 3500 MW of facility capacity, has been set for geothermal energy. (Table 1)

According to the Provisional Long-term Energy Supply and Demand Outlook, published by the Energy Advisory Committee of MITI in 1979, targets for the development geothermal energy are 1000 MW in 1985, 3500 MW in 1990 and 7000 MW in 1995. (Fig. 5) It may be necessary to adjust these figures over time and there is currently no geothermal target for the year 2000.

Problems The generation capacity of geothermal power plants in Japan has grown to 162 MW since the inauguration of the first industrial power station in Matsukawa in 1966. (Fig. 1, Table 2) Two new plants are under construction, and combined they will have a capacity of 53 MW by 1982. (Fig. 2) In more than twenty geothermal fields, test wells will be drilled this year. (Fig. 3)

Judging from this data, it will not be easy to attain development targets outlined above.

The government, meanwhile, has established separate policy measures for each of the different types of problems which grow out of efforts to develop such an energy source. Areas in which the government has policy measures strategies include regulatory, technological, financial and environmental problems.

Regulatory Environment and Policy Measures Civil Codes and the Hot Spring Law both affect geothermal development. In addition, the development of fields in natural parks is restricted by the Natural Parks Law.

Several procedures related to the development of a geothermal field are given below. After a comprehensive land survey, the development company drills a test well with drilling permission from a local government, in accordance with the Hot Spring Law. The ownership of the geothermal resource belongs to the landowner according to Civil Codes, and as a result the development company must buy the land.

Although it is preferable for the company to acquire the land ownership for a promising vast field, this is often not realistic because of the expense involved.

In addition, if company B hears about the fact that company A has found a superior geothermal field, these are currently no regulations which would restrict company B from drilling test wells near the field. In other words, there are no legal measures for protection of discoveries and no geothermal exploration rights, such as those resembling mining rights.

The establishment of "geothermal exploration rights" and a revision of Civil Codes and the Hot Spring Law has been suggested. However, it will take more than ten years to revise these laws because thousands of people who make a living with hot springs, will surely oppose such legal revisions. Many Japanese enjoy taking a hot spring bath and hot spring resorts have been popular destinations for travelers for hundred of years.

Another regulatory factor is the Natural Parks Law. More than half of the potential geothermal fields are in natural parks areas including national parks and local parks. Before drilling a test well in a natural park, a geothermal development company must have drilling permission according to the Natural Parks Law. Some people are very reluctant to have geothermal power plants in a natural park because of their "poor looks, dirty hydrogen sulfide(H_2S) and polluted hot water."

In response to this, one proposal is to enact a geothermal promotion law, which would make it unnecessary to receive drilling permission under the Hot Spring Law and Natural Parks Law. This may prove to be not feasible.

Technological Problems and Policy Measures
Following the oil crisis in 1974, the "Sunshine Project,"aiming at research and development of new technology for solar, geothermal, coal and hydrogen energies, was started. Areas of technological development addressed in the Sunshine Project for Geothermal Energy are outlined as follows:

(A) Technology for exploration and extraction of geothermal energy Current exploring techniques largely depend upon those used for petroleum resource exploration, both in method and equipment. However, in order to attain adequate precision in the future, new exploring techniques suited to geothermal prospecting are necessary and will be developed.
With regard to geothermal well drilling techniques, progress is being made in applying the air drilling method as well as the conventional mud drilling method. In the future, drilling will be made into rocks with even higher temperatures(300 - 400 ℃); therefore, the development of high temperature and corrosion resistant materials is compulsory.
Together with a drilling machine, much more severe conditions will be imposed on the well logging instruments, with respect to their heat resistance, pressure resistance and corrosion resistance; consequently, efforts must be made to improve their performance capabilities. In the interests of preventing environmental disruption and reducing heat loss, incline drilling may also be widely adopted.
Consequently, the object of studies is to establish methods for confirming the amount of geothermal deposits and to develop technology for exploring and assessing geothermal resources as well as technology for excavating high-temperature rock in order to reduce the risks involved in development.

(B) Technology for power generation utilizing hot water The power generation system today is limited to the use of natural steam, but the effective use of hot water associated with natural steam must be developed. For this purpose, the development of binary cycle power generating system using low enthalpy fluids such as Freon or Isobutane as the carrier of heat energy, a combined cycle system combining the former with the natural steam system and the total flow generation system are expected.

The object of studies is to develop the technology for corrosion-resistive materials, technology for high-efficiency heat exchange, etc., and to develop a high-efficiency binary-cycle power generating system by late 1980's. Test runs were undertaken on a 2-system(1 MW hot water type, combination hot water and steam type). A 0.3 MW system has been developed in order to develop the high-efficiency two-phase flow rotary expander.

(C) Technology for a hot dry rock power generating system The development of hot dry rock fracturing techniques and artificial hot water and steam evolving system for extracting thermal energy possessed by hot dry rock is very important and a challenging theme.

There is a high potential for the development of these power generation systems, utilizing the aforementioned techniques of forming artificial hot water and steam systems.

Therefore, studies are being carried out to develop technology for fracturing hot dry rock, technology for forming manmade hot water and steam systems, etc., and to develop high-efficiency and large-capacity hot dry rock power generating systems by the middle of 1990's.

(D) Technology for multi-purpose utilization of geothermal energy and environmental preservation Effective use of hot water associated with geothermal power generation is important in view of reducing power generating costs by allocation and the contribution to regional development. The power generating plant for multi-purpose use of geothermal energy may be called a local welfare type plant. The multi-purpose use of geothermal energy will also be highly effective in preventing environmental pollution caused by the discharge of hot waste water.

Environmental effects brought on by geothermal fluids must be fully controlled. These include corrosive gases and chemical components discharged from geothermal fluids, as well as hot water and solids, adversely affecting humans and the ecological systems. It is imperative that comprehensive techniques for environmental protection should be established.

Therefore, studies are being carried out to develop technology for transporting geothermal fluids, and to develop geothermal energy utilization systems for regional heating, agriculture and other purposes.

Furthermore, studies aimed at developing technology for environmental preservation in order to prevent adverse effects on the natural environment and ecosystem from the extraction and utilization of geothermal fluids are being carried out.

Financial Problems and Policy Measures Among nuclear, geothermal, coal, gas, oil and hydroelectric energy, geothermal is not the cheapest (nuclear), nor is it the most expensive(hydroelectric).

A geothermal development requires a large amount of investment and assumes large risks in the exploration of a promising field. Therefore, it is important to reduce these financial burdens by giving financial incentives including subsidies, low interest loans and preferential tax treatment. The government itself may also support various surveys directly.

The first of these government supported surveys is the nationwide geothermal resources survey which has been undertaken by the newly established New Energy Development Organization (NEDO). The NEDO is almost fully supported by the government. In this three-year project, potential areas will be re-evaluated by Landsat data, gravity data, Qurie-point analysis data, and synthetic aperture radar data. The survey has just begun to collect radar data and the results of this survey will be available after all the data has been completed.

As a second type of survey, local rough surveys have been carried out by NEDO with government funds in several areas. Under this survey, in each selected area, five geothermal survey wells(1000 m depth) and two wells (1500 m depth) will be drilled for two years. At the same time, air and water pollutants, as well as hot springs have also been investigated.

Thirdly, the government encourages private companies through a test-well drilling subsidy. A company can receive one-half of the expenditures for test-wells from the government and it must repay the government if the company successfully builds and operates a plant.

Fourth, the Japan Development Bank and Hokkaido-Tohoku Development Bank have played an important role in promoting geothermal development by providing low interest loans. The fact that these banks give a loan to a company serves as a signal to the "city banks" that the company is worthy of commercial credit.

Finally, special accelerated depreciation rules and tax credits are applied to companies that have invested in geothermal plants or geothermal green houses.

Combined, these five measures reduce business risks and have accelerated developments in the private sector.

Environmental Problems and Policy Measures The impact of the establishment of geothermal power plants on the environment may be divided into three areas; bad appearance, dirty hydrogen sulfide and arsenic hot water.

There are some people who, in order to preserve the scenic beauty of natural areas, are opposed to geothermal plants because of the appearance of mechanical facilities; pipelines, transmission and cooling towers. Recently electric companies have been attempting to cover the facilities with natural plants and trees, or lower building heights.

Secondly, geothermal plants discharge hydrogen sulfide (H_2S) into the atmosphere. Under the provisions of the Offensive Odor Control Law (not the Air Pollution Control Law), the discharge of hydrogen sulfide(H_2S) is regulated, except hot spring areas. Hot springs naturally discharge quite a lot of H_2S and this is most often above the emission standard. All the geothermal plants in hot spring areas have large cooling towers and discharge H_2S together with large amounts of fresh air and steam through these. In addition to these efforts, the Environment Agency plans to implement H_2S regulations similar to those of Northern Sonoma County, California and as a result, H_2S emission control technology has been developed by the Agency of Industrial Science and Technology, MITI.

Finally, geothermal water usually contains arsenic at levels above the environmental quality standard; 0.05 ppm. Therefore, all the hot water utilized in a plant is re-injected into the earth in order to prevent water pollution. In addition to this measure, the Kyushu Electric Power Co. has developed arsenic control technology with a government subsidy. Unfortunately this control technology cannot as of yet, be utilized. Although many people near a geothermal plant hope to have "hot spring water" by means of this new arsenic control device, some people are very reluctant to agree to use this device even though quite a number of Japanese drink a cup of arsenic spring water for medical treatment.

New technologies and new layout techniques make geothermal plants much more appealing to people.

Strategies for Consensus Building People who are used to enjoying hot springs worry about hot springs drying out because geothermal plants use much more geothermal energy than hot springs. Some people are therefore even opposed to surveys. In order to demonstrate large-scale hot water utilization, several national projects were begun in 1980 with the financial support of MITI. Among these, the largest project attempts to produce up to 800 t/h of 115℃ water from river water through a heat exchange process utilizing 1000 t/h, 150℃ used, geothermal water. This 115 ℃ water is then transported to twelve villages. This is, in direct utilization of geothermal resources in Japan, the first project to supply water at over 100℃. It will take four years to construct and will require $20 million.

Conclusions By the end of this year, I expect to see very significant achievements realized as a result of our efforts. These include the completion of the nation wide air-borne survey. the compiling of over 20 sets of logging data from five local surveys, and I expect more than fifty test wells to be completed in twenty different areas.

From a technical and social stand-point, this year will be critically important. It is my sincere hope that our combined efforts will prove to be Japan's first giant step toward the implementation of geothermal energy systems.

Table 1. Alternative Energy Supply Targets FY 1990 approved by the Cabinet on November 28, 1980

Types of Alternative Energy Sources to Be Developed and Introduced and Their Supply Targets

Types of alternative energy sources	Supply target * (Unit: 10,000 kl)		Remarks	(Reference) FY 1977 (Unit: 10,000 kl)	
Coal	12,300	35.4%	The supply of coal is 163.50 million tons.	5,681	50.9%
Nuclear energy	7,590	21.8%	The supply capacity of nuclear energy is reflected in the electricity generated at nuclear power plants. The output of nuclear plant facilities is between 51.00 and 53.00 million kilo watts and the annual amount of electricity generated is 292.0 billion kilo watt hours.	1,542	13.8%
Natural gas	7,110	20.4%	The supply of natural gas is the sum of the quantity of imported natural gas (45.00 million tons) and domestic natural gas (7.60 million tons).	1,940	17.4%
Hydro-electric energy	3,190	9.2%	The supply of hydroelectric energy is equivalent to the electricity generated at hydroelectric power plants. The output of hydroelectric power plants is 53.00 million kilo watts. Within this total, 26.00 million kilo watts come from general hydro-electric power plants (including all types of hydroelectric plants except pumped-storage power plants) and 27.00 million kilo watts come from pmped-storage hydroelectric power plants. The annual amount of electricity generaged is 123.0 billion kilo watt hours.	1,941	17.4%
Geothermal energy	730	2.1%	Geothermal energy includes electricity generated by thermal power plants utilizing geothermal energy. The output of these facilities is 3.50 million kilo watts and the annual amount of electricity generated is 24.5 billion kilo watt hours.	16	0.2%
Other alternative energy sources	3,850	11.1%	Other alternative energy sources include solar energy, coal liquefaction fuel, etc.	38	0.3%
(Reference) Total	350 million kl	100.0%		112 million kl	100.0%

(Note)* The supply target of alternative energy sources represents figures which have been converted into equivalent crude oil quantities.

Table 2. Geothermal Power Plants (inclusive of those under construction, as of April 1981)

	Name of Power Station	Name of Company	Location	Maximum Capacity (MW)	Year of Commission	Electric Production FY 1979 (Gwh)	Conversion Cycle	Inlet Temp. °C	Inlet Pressure ata
Existing Facilities	Matsukawa	Japan Metals and Chemicals Co., Ltd.	Iwate Pref.	22	1966	176	–	190	3.5
	Otake	Kyushu E.P.Co.	Oita Pref.	12.5	1967	64	Flash	127	2.5
	Onuma	Mitsubishi Metal Co.	Akita Pref.	10	1974	62	Flash	114	1.8
	Onikobe	E.P.D. Co.	Miyagi Pref.	12.5	1975	59	Flash	134	1.7
	Hatchobaru	Kyushu E.P.Co.	Oita Pref.	55	1977	376	Double Flash	164	7.0
	Kakkonda	Tohoku E.P.Co. Japan Metals and Chemicals Co., Ltd.	Iwate Pref.	50	1978	364	Flash	140	3.5
Under Construction	Mori	Hokkaido E.P.Co. Donan Chinetsu Energy Co.	Hokkaido Pref.	50	1982	–	Double Flssh	164	7.0
	Suginoi	Suginoi Hotel	Oita Pref.	3	1982	–	Flash	140	4.0

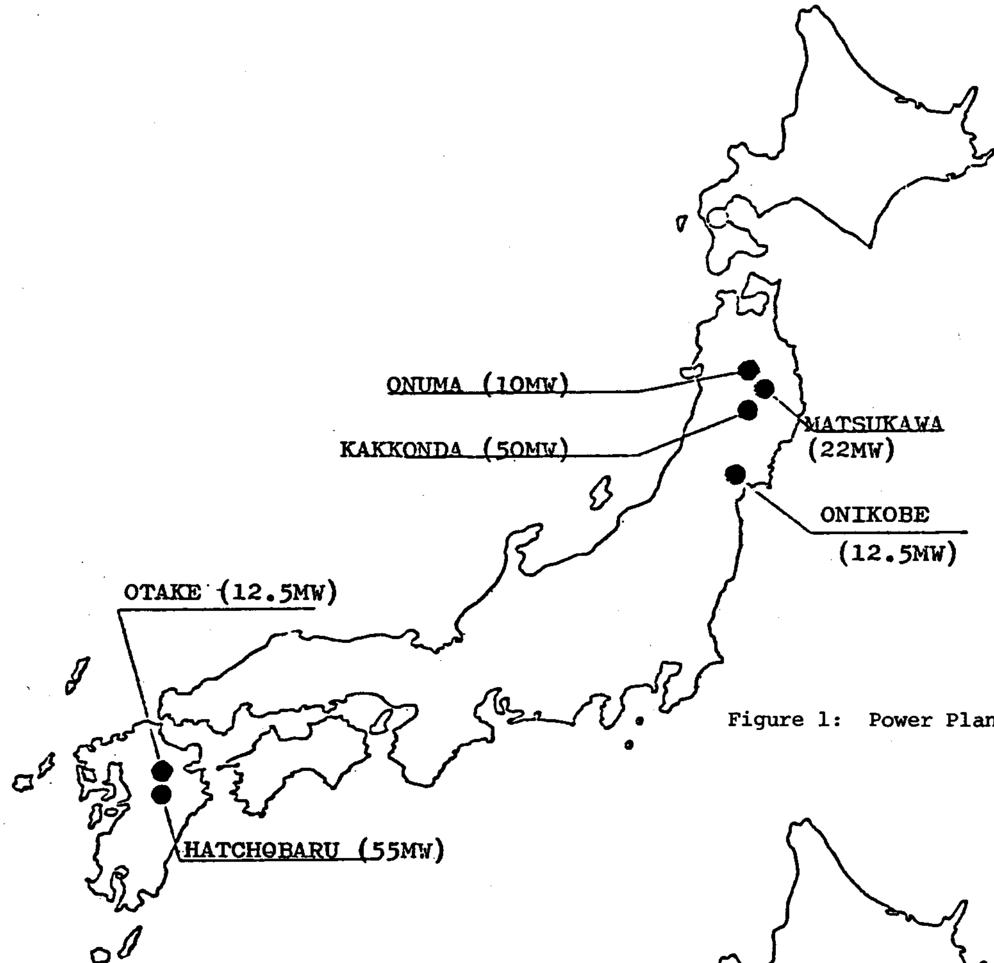


Figure 1: Power Plants On-Line

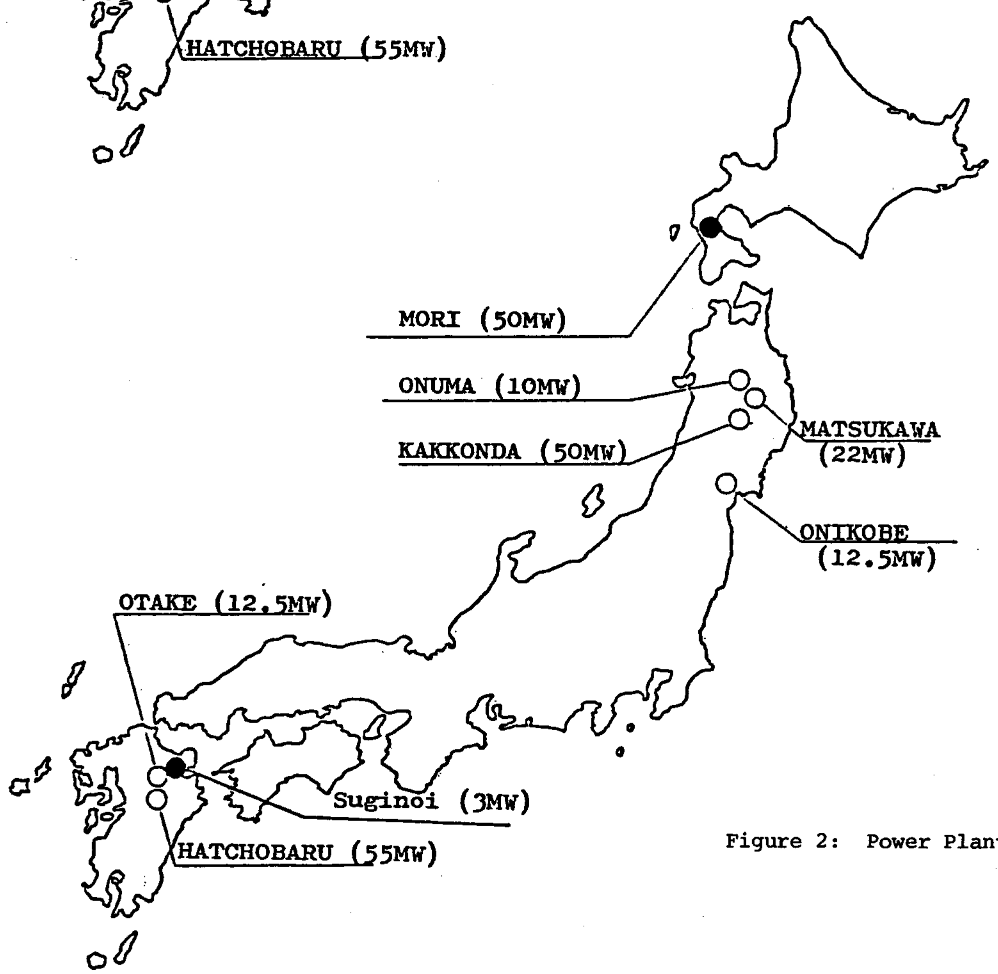


Figure 2: Power Plants Under Construction

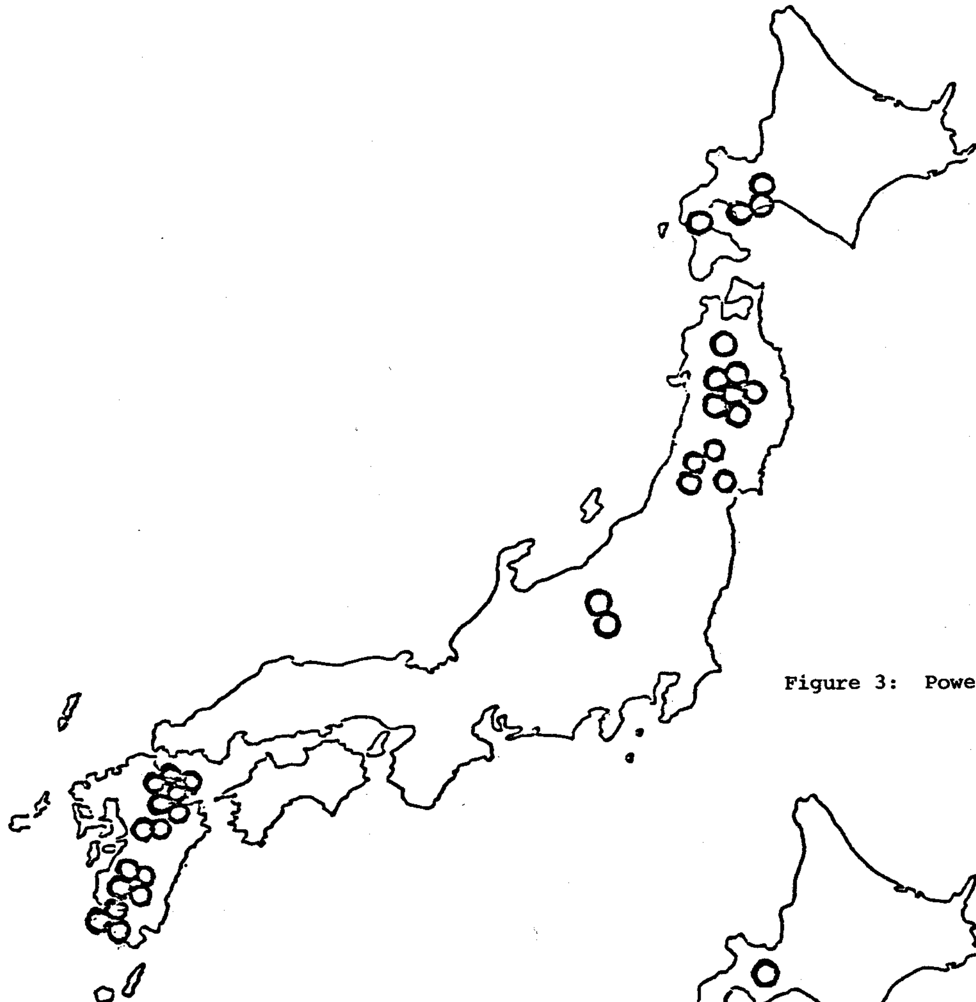


Figure 3: Power Plants Planned

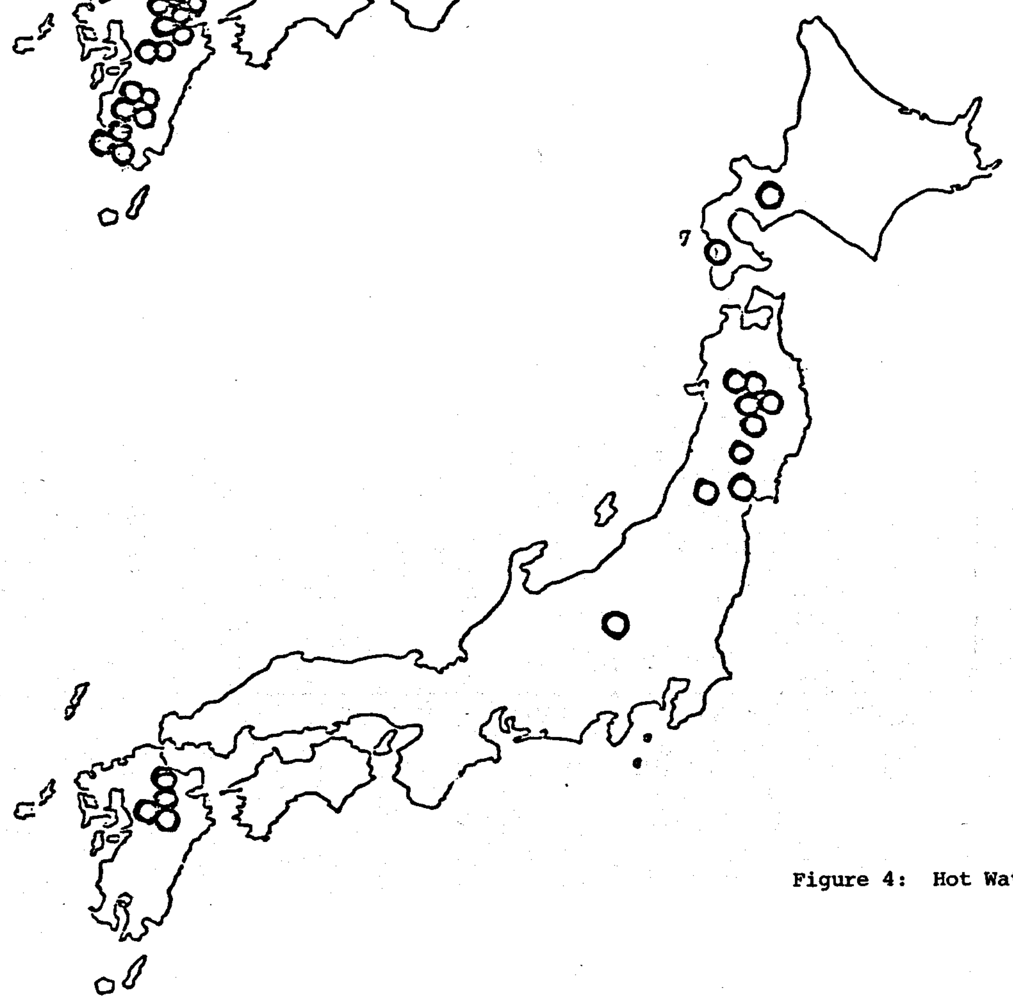
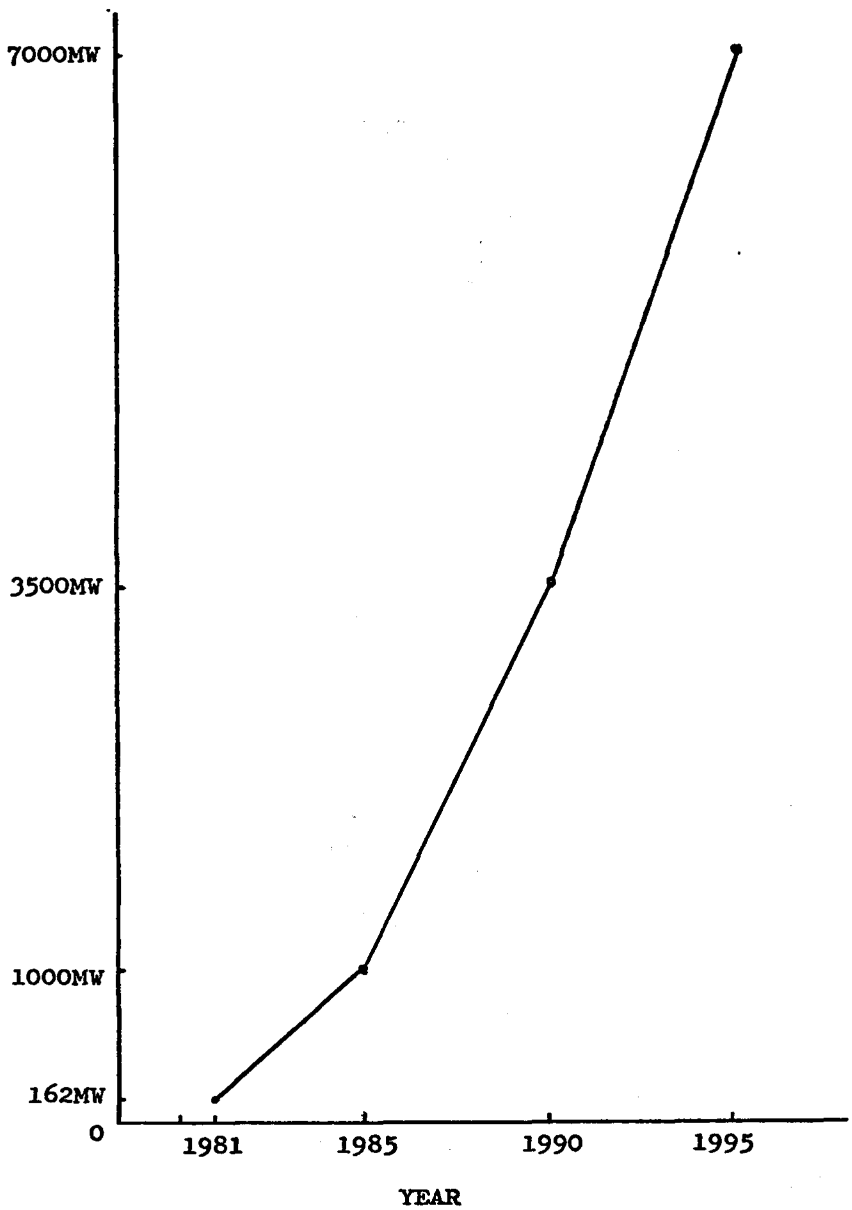


Figure 4: Hot Water Utilization

Figure 5: Geothermal Energy Target



Annex

Geothermal Projects Planned for Fiscal 1981

Unit: million yen
(million $)$1=¥210

Project Name	Budget for FY 1981	Budget for FY 1980
Nationwide geothermal resources survey	2,518 (12)	1,846 (9)
Local rough surveys	2,754 (13)	2,600 (12)
Test-well drilling subsidies	2,728 (13)	2,401 (11)
Environmental assessment of large scale power generation using deep geothermal reservoir (Hohi)	2,604 (12)	3,004 (14)
Field survey to test geothermal resource exploration technology (Sengan, Kurikoma)	1,012 (5)	539 (3)
Hot water utilization projects	1,663 (8)	932 (4)
Hot water supply from deep geothermal reservoir	678 (3)	262 (1)
U.S.-Japan joint research on power generation on hot dry rock. etc.	600 (3)	603 (3)
Others	2,609 (12)	2,736 (13)
T o t a l	17,166 (82)	14,923 (71)

THE GENERATION OF ELECTRICITY FROM GEOTHERMAL RESOURCES IN ENGLAND

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Introduction: Two types of geothermal reservoirs exist in the United Kingdom, permeable formations in sedimentary basins, the largest being perhaps 4km deep, and hot dry rocks. Temperatures exceeding 200°C are unlikely to be found within 7km of the surface in the dry reservoirs and the maximum temperature expected at the bottom of the sedimentary basins is 125°C. (Burley 1980)

Both resources are of rather low quality, in that both have about normal temperature gradients, one is rather cool and the other depends on unproven technology. However, the price of fuel in the UK is so high that both merit investigation at least, as sources of electric power.

Hot Dry Rocks: The techniques required to render dry rock permeable have been the subject of an experiment at the Camborne School of Mines and financed by the UK Department of Energy and the European Commission. The original concept of a hot dry rock reservoir as proposed by the Los Alamos National Lab (fig. 1) (Smith 1975) has been discarded as it is now realized that the natural fault system within the rock determines the growth of the fracture system. At Los Alamos the aim of producing one fracture of sufficient area to be able to provide hot water over the 20 year's life of the power station has been replaced (fig. 2) by a number of smaller fractures in parallel (Los Alamos Scientific Laboratory 1980).

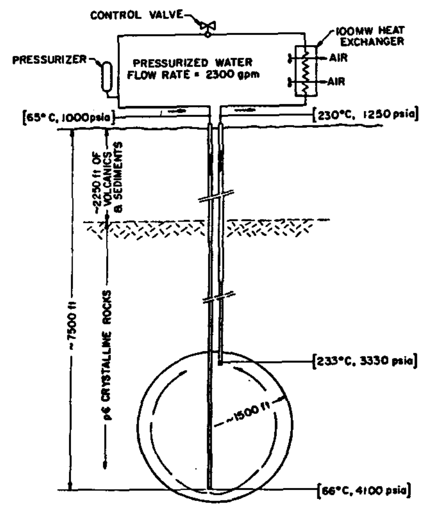

Figure 1: Original Hot Dry Rock concept.

The Camborne approach questions whether the joint structure would permit the fabrication of such a system and suggests a different geometry. It is believed that the reservoir is highly fractured and an idealized plan view is shown in figure 3. Hydrofracturing just serves to open some of the natural flow

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paths. Batchelor (1980) believes that the connection from the borehole to the joint system offers the greatest impedance to water flow and has demonstrated that the use of explosive charges may substantially increase the number of connections.

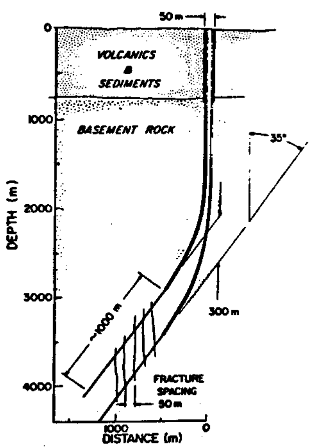

Figure 2: Reservoir planned for Fenton Hill Phase II System.

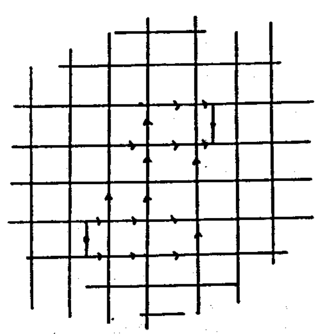

Figure 3: Idealized plan view of natural joints in granite.

Great care must be taken when using explosives to fracture rock since if the explosion is incorrectly designed, plastic deformation will occur in the rock around the well bore making it impermeable (fig. 4). Batchelor's unfocused charges serve to produce a highly fractured zone around the well bore (fig. 5) and the fractures were subsequently grown by hydrofracturing. This explosive pretreatment reduced the impedance substantially but needs to be confirmed on a commercial scale. The boreholes at Camborne were just 40m distant and at a depth of just 300m. A new reservoir is now being constructed at 2000m where the earth's stresses will be more representative of those at "commercial depths" of 5km.

The impedance of the loop at Camborne had an impedance of 0.7 GPas/m^3 when flowing $<$ .01/m^3/s with negligible water loss and the production borehole being held at atmospheric pressure.

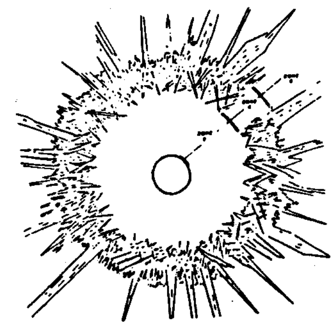

Figure 4: Result of explosive treatment of borehole with too high a charge. Note impermeable zone caused by plastic deformation.

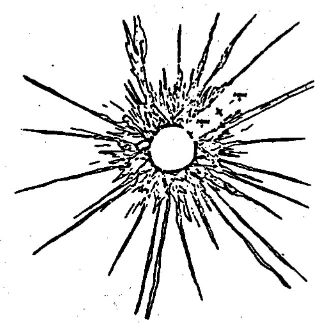

Figure 5: Satisfactory explosive treatment of borehole.

It is possible to reduce this impedance by applying a back pressure to the production borehole thus pressurizing the reservoir and inflating the fractures. However this also reduces the total pressure drop across the reservoir and does not always result in an increased flow rate. For reservoirs operating at zero back pressures it is possible to develop a simple economic model to calculate generating costs. The results of such an analysis yields the curves shown in figure 6. The 1980 generating costs in the UK were 2.2p/kWhe so an impedance of 0.1/GPas/m^3 will be required for economic operation (White 1981).

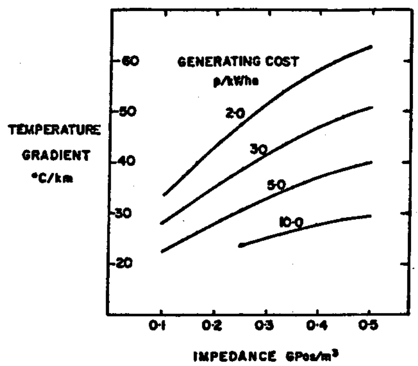

Figure 6: Optimum generating costs (1980) for Hot Dry Rocks. CEGB selling price was 2.2p/kWe for same period.

Sedimentary Basins

Feeedwater Heating: The extraction of heat from moderate temperature permeable strata in sedimentary basins is a proven technology with the French pioneering the use of production reinjection doublets. With a maximum temperature of just 120°C, the low conversion efficiency of the Rankine cycle would, at first sight, preclude the direct generation of electricity from these sources. However it is possible to generate greater quantities of electricity from a given low temperature source by incorporating the geothermal fluid into a conventional steam power cycle (Kestin et al. 1978). All the steam-driven power stations in the CEGB, and most other utilities, have feedwater heaters which use steam bled from the turbines to preheat the boiler feed water (fig. 7). These are employed since it is a consequence of the second law of thermodynamics that the heat of combustion of the fuel will be converted into work with a greater conversion efficiency, the higher the boiler inlet temperature. The geothermal heat may be supplied to the steam cycle by replacing some of the feedwater heaters and allowing the bled steam to remain in the turbine, thus generating more electricity (fig. 8).

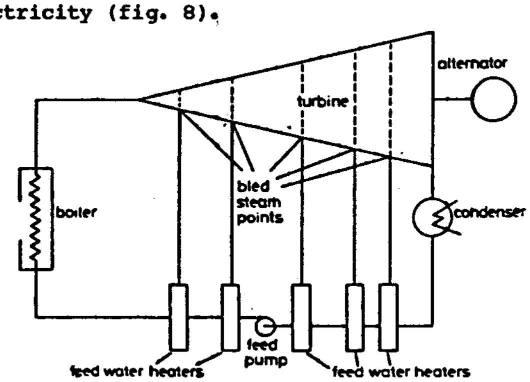

Figure 7: Conventional boiler cycle.

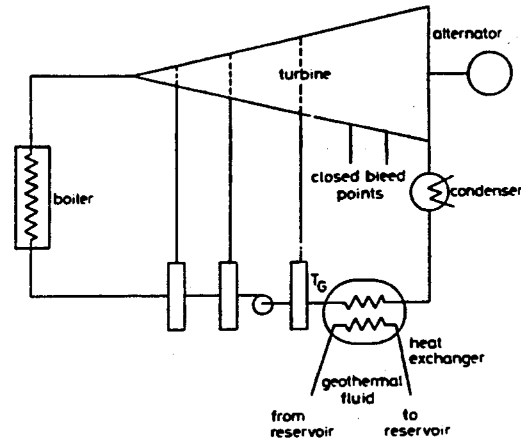

Figure 8: Boiler cycle modified to accept geothermal heat.

An analysis of the thermodynamics of such a hybrid plant indicates that the efficiency with which the heat contained in this steam is converted into work is determined by its enthalpy at the bleed point and at the condenser. Varying the geothermal temperature T_G just alters the quantity of steam so saved and not the conversion efficiency (White 1980). Conversion efficiencies of as high as 11% for geothermal well head temperatures of 100°C may be expected whilst the efficiency of a Rankine turbine generating from the same source will probably be less than 6.5% (Milora & Tester 1976).

Marchwood Experiment: The UK Department of Energy required a site to drill an exploratory geothermal well to help assess the geothermal potential of the Hampshire Basin. The CEGB offered the free use of a site adjacent to an old 8 x 60 MWe oil fired power station which could later be provided with feedwater heating should the borehole encounter a suitable reservoir.

The extra steam flow thorough the last stages of a turbine provided with feedwater heating could cause reduction in a stage efficiencies and so a simulation experiment was performed using two turbines.

A crosslink was made between two adjacent sets which allowed the interchange of the inlets to the third feedwater heaters. The turbines were run for a period of one hour with the bleeds to feedwater heaters 1 and 2 of set A closed (fig. 9). In this way, set A experienced external feedwater heating and the fuel efficiency ζ, or heat rate, of the set was determined. The crossover was then removed, and the sets were run in the normal condition (fig. 10). The change in fuel efficiency of set A between the two runs enabled a calcula-

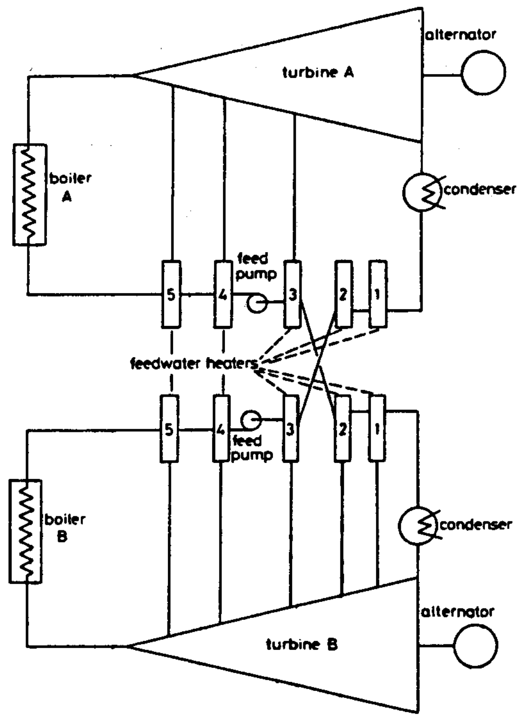

Figure 9: Crosslink experiment for simulated geothermal feedwater heating.

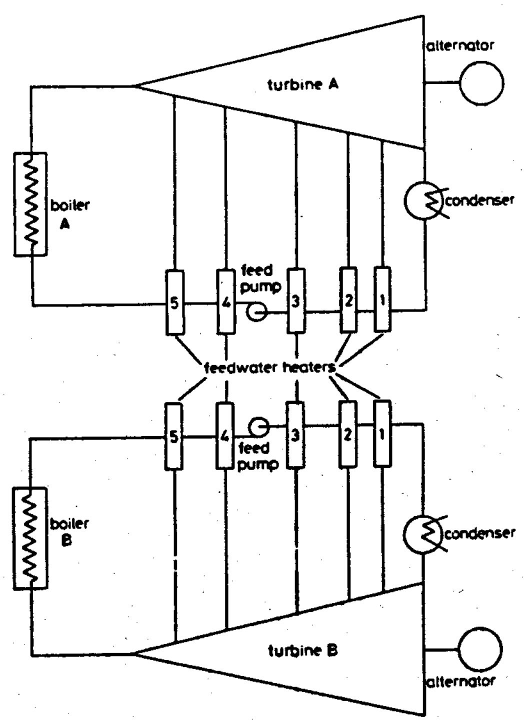

Figure 10: Normal operation.

tion to be made of the extra output caused by using geothermal heating to keep the inlet temperature of the third feedwater heater at 90°C. The result of the test was an increase in fuel efficiency of 2.8 ± 0.2 % equivalent to a conversion efficiency of 11%.

Further calculations showed that the last stages of the turbine suffered a decrease in efficiency of 0.5 ± 0.5%.

The 2.8% increase in output was accompanied by a 16% increase in pressure drop from bleed point 1 to the condenser and a 6% increase from bleed point 2 which could severely affect the blades' lives if the turbine were run for some time in this off design mode. Ideally a new power station, built over a suitable geothermal resource, would have feedwater heating included in the design stages with the turbines' final stages being suitably increased in size.

Unfortunately, the Department of Energy well encountered water at a shallower depth than expected, the water temperature being just 70°C, not the predicted 90°C. No decision has been made by the department if and how to use the well. Paper studies, however have shown that aquifer 3km deep at 100°C having a transmissivity of about 3.5 x 10^{-4} m^2/s could produce electricity competitively with fossil fuel, if used in a hybrid station (White 1979).

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SOME POSSIBLE RESTRAINTS ON GEOTHERMAL

DEVELOPMENT IN NEW ZEALAND

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Introduction Using the Wairakei field as a model, Donaldson & Grant (1978) recently suggested that if all the major New Zealand geothermal fields, except Whakarewarewa, were exploited for electric power production, we might anticipate a total generating capacity of as much as 2500 MWe. Their field-by-field breakdown is given in Table 1. While about half of this total is speculative, their figures are also conservative. Being based on the Wairakei system, the power station generating capacities are controlled by the acceptable pressure drawdown in the reservoirs, rather than any lifetime factor. Thus, the power generation capability of these fields may continue through several plant amortization periods. Both Thain (1980) and Donaldson and Grant (1981) consider that Wairakei could continue to produce power at near the present rate for a very long time. Alternatively, the successful maintenance of pressure in the reservoir, as, for example, by reinjection, could allow a shorter term, higher generating capacity.

Field	Proven	Inferred	Speculative
Wairakei	150		
Tauhara	100		80
Broadlands	120	30	
Kawerau	100		30
Waiotapu-Reporoa		150	100
Orakeikorako		50	50
Rotokaua		50	100
Tikitere-Taheke		75	75
Waimangu		50	100
Te Kopia		20	20
Mokai			170
Atiamuri			30
Tokaanu-Waihi			100
Ketetahi			25
Ngawha		200	500
Totals	470	625	1380

Table 1: Estimated potential power station output (MWe) for New Zealand geothermal fields if these were exploited in the same manner as Wairakei is currently (from Donaldson & Grant, 1978)

Not only do we appear to have this generating capacity available, we also have proven, operating systems in Wairakei and Kawerau. As Thain (1980) has pointed out, power from the Wairakei power station first flowed into the New Zealand national electricity grid on November, 15, 1958 and the full coupling of the system was completed in October, 1964. Since that time this plant has had one of the best records for reliability of any power station in New Zealand. The annual station load factor has consistently been between 85% and 90% and the availability factor in excess of 85% for most of the past decade. Thain (1980) also indicates that the plant has not been expensive to operate, the operating costs being some 16.5% less than the average costs of the hydroelectric plants in the North Island (on a per unit generated basis).

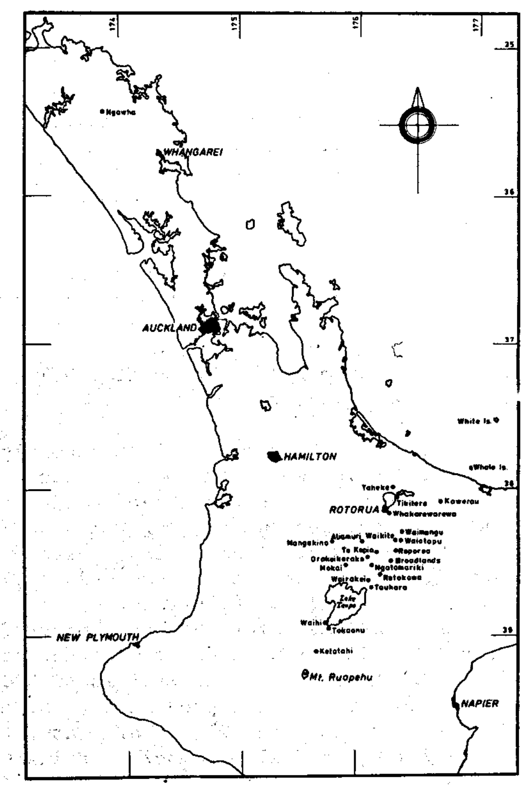

Fig. 1: New Zealand Geothermal Fields

At Kawerau, a field that has been exploited commercially since the early/mid-1960's, the output is still being expanded. Since 1978, three new wells have been drilled and another deepened. With the connection into the system of the very large producer KA21, the steam supply to the Tasman Pulp & Paper Company mill has been increased from 120 tonne/hr to 200 tonne/hr (Denton, 1980). Denton (1980) anticipates a further increase to 270 tonne/hr in the very near future.

In the light of this considerable power generation potential and the success of our current plants, why has our progress in development of our resources been so slow? I should like to look here at what I think may be some of the background reasons. I will separate these into two categories: those related directly to the exploitation process, and those, associated with other aspects of energy development in New Zealand or with environmental concerns, that may have had a less direct influence.

<u>Current Status of New Zealand Geothermal Projects</u> Before I discuss the problems of geothermal development in New Zealand, let me first indicate the present status of our program. I will not touch on Wairakei as Thain (1980) discussed this field in some detail in his presentation last year.

Broadlands, due to its imminent exploitation for power production, is currently the site of the majority of the field testing. Over the past two to three years the number of investigation/production wells has been increased to 37. The latest of these, BR37, was drilled outside the hot primary field area, the aim being to find permeability for reinjection external to the main reservoir. No good permeability horizens were, however, found in this 1400m hole. The bottom hole temperature was close to 200°C.

Most of the other tests carried out recently in this field have been detailed by Denton (1980). He indicates that reinjection tests have now been carried out in four wells (BR7, BR34, BR28, and BR13) with varying degrees of success. In the long term test using BR7 which began in April, 1976, 665 tonne of separated geothermal water had been injected to March 1980 without apparent adverse effects (Bixley & Grant, 1979). This well is of moderate permeability and accepted 21.5 tonne/hr at 180°C and WHP 10.1 bg, 27 tonne/hr at 140°C and 7.4 bg, and 27.6 tonne/hr at 112°C and 3.3 bg.

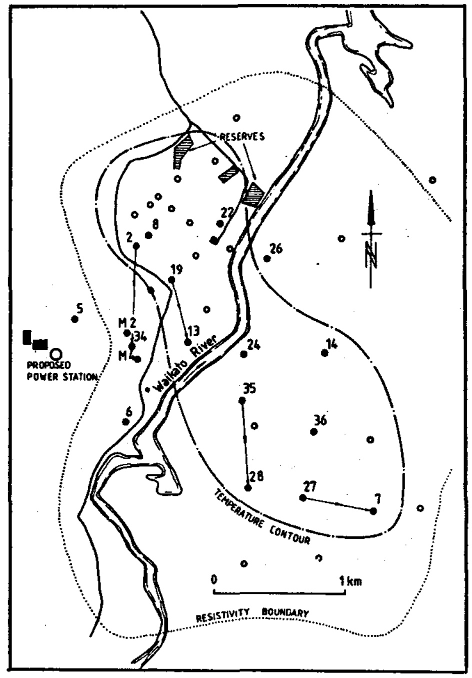

Fig. 2: Injection Tests
At Broadlands, New Zealand

In the test using BR34, 3.6×10^5 tonne of separated water were injected at temperatures between 80°C and 95°C over a total period of 1960 hours. This well initially accepted the water at up to 200 tonne/hr but its capacity to accept this water decreased to about one third during the test. Silica deposition took place in the transmission pipeline, in the injection well, and in the formation away from the well (Denton, 1980).

Late last year, 1980, the remaining two tests were still in progress. Temperature/pressure fluctuations and mechanical problems were delaying the test using BR28. During operation a flow of 160 tonne/hr at 150°C and 3.1 bg WHP was achieved. The fourth test was only just underway.

Other tests being carried out at Broadlands and discussed by Denton (1980) include a study of silica deposition and an attempt to stimulate well BR14 by use of injection/discharge cycling. This technique had previously resulted in significant improvements in output of wells BR13 and BR23 (Bixley & Grant, 1979). It appears that in the formations around BR14 existing fractures in the rock open during the injection cycle when the pressure is high enough but close again when the pressure drops. Further tests with higher injection flows and propant injection are proposed (Denton, 1980).

Current plans are for the first 50 MW unit at Broadlands (Ohaki Power Station) to be commissioned in October, 1986; the second, one year later. Should the field be capable of supporting the extra draw-off, a further 50 MW unit will be added at a later date.

At Ngawha, on the North Auckland peninsula, wells have now been drilled. The first six three of these (NG2, NG5, and NG7) encountered little permeability and may have suffered from mud damage. The remaining three wells (NG3, NG4, and NG9) are all good producers, NG4 and NG9 having multiple feeds. To stop the interzonal flow in NG9 and yet get the benefit of both feeds, an internal pipe has been lowered down from the surface and sealed to the casing between the two feed zones. The double completion is apparently successful. The internal pipe expanded some 3 m on warm-up.

Electricity Supply and Demand in New Zealand

Currently some 6% of New Zealand's electrical energy is produced from its geothermal resources; 85% comes from hydro-power, and 8% comes, or is planned to come, from natural gas. Although this latter supply has a limited lifetime, at an estimated 35 years its decline should have no effect on the short term figures quoted here. New Zealand geology also suggests that other offshore oil and gas fields are likely.

At these current levels New Zealand still has plenty of untapped energy reserves. I have already indicated a geothermal electrical energy potential of from 10 to 25 times that currently generated; for our water-power we have a factor of about 3; and we have barely touched our coal. The reserves of the latter are conservatively estimated at somewhat in excess of 3 billion tonnes.

Euromoney, in a recent survey on New Zealand (September, 1980), titled its energy chapter "A Thousand Years of Energy Reserves." The subtitle read "New Zealand is an energy planner's dream: it has more coal and hydroelectric potential than it needs for a century or more. It also possesses the Maui field, the fourteenth largest gas field in the world."

Currently, in a dry year, New Zealand can produce some 25,000 GWh of electricity. The demand is about 22,000 GWh. Thus, even under these worst conditions, there is a significant surplus. With the planned electrical development, by 1985, the generating capacity will be about 32-33,000 Gwh (dry year).

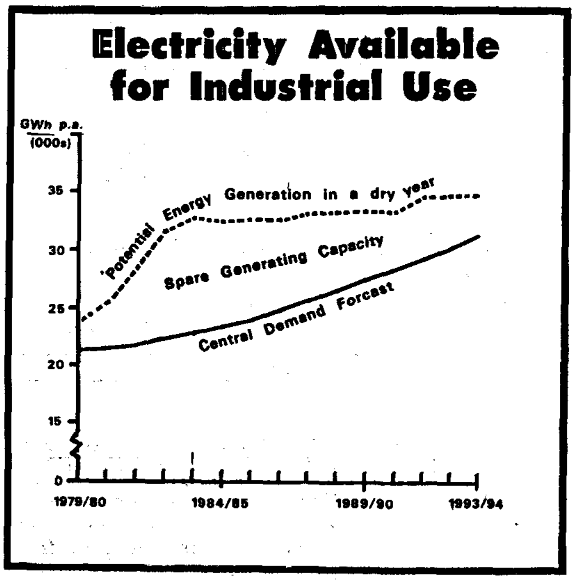

Fig. 3: New Zealand electrical energy supply and demand for the next 15 years (Plot does not include planned industrial expansion of 6,500 GWh p.a. by the late 1980's)

Obviously, there must be plans to utilize this surplus energy. New Zealand is, in fact, just now entering into a period of energy-intensive industrial development. I list some of the scheduled projects (by category) and their estimated annual energy requirements in Table II. These projects are virtually all scheduled for completion by the mid-to-late 1980's. Thus, by the end of this decade the total power requirement of 6500 GWh for these projects will be part of our electric load. There will be no dry year surplus at that time.

Table II

Plant	Power Required GWh/yr	Construction Period
Energy Sector		
Oil Refinery Expansion	1000	1981-83
Synthetic Gasoline	700	1983-86
Chemical Methanol	300	1982-84
Ammonia/Urea	300	1980-81

Table II cont.

Plant	Power Required GWh/yr	Construction Period
Aluminum		
Comaleo Expansion	400	1980-83
New Plant	1250	1981-88
Steel		
NZ Steel	1000	1981-85
Ferro-silicon	200	1981-83
Cement		
Whangerei	150	1980-82
Oamaru	250	1981-83
Pulp & Paper		
NZ Forest Products	450	1982-85
Fletcher/Carter or Northern Pulp	210	
CSR Baigents	300	1982-84
Total	6500	(1980-88)

Possible Reasons for Slow Development of our Geothermal Resources - (1) Directly Related to Exploitation Although the Wairakei reservoir was exploited on a try-and-see basis and we have made a few mistakes, its development as an energy resource has been a successful exercise. We have also learned a lot by carrying it out. Several effects that have shown up are, however, of some concern and these, together with changing public attitudes and increasing technical regulation, must play a role in our decision making concerning future development.

a. Pressure Drawdown As Thain (1980) pointed out one of our main concerns with regard to the Wairakei reservoir is the pressure drawdown that has occurred due to the exploitation. Not only does this drawdown place a restraint on the amount of energy that we can extract from this reservoir, it has also altered some of the characteristics of the field. It extends not only throughout the Wairakei reservoir, but also, although to a lessening degree as we get further away, right through the adjacent, connected, Tauhara reservoir. It is also believed to be having side effects on activity as far away as the Taupo lakeshore (5 to 6 miles).

This drawdown is by no means unique to Wairakei. The Ohaki section of the Broadlands reservoir was showing some effect in the late 1960's, towards the end of some significant test discharge. There are also indications that there has been some drawdown in the Rotorua area due to the exploitation there (Donaldson, 1980).

While the limitation on the rate of withdrawal of energy may have engineering and economic consequences, the total amount of energy that may be extracted from the field may not be greatly altered. Theoretically, using an ideal model, it is only the time-scale that is changed. The potential side effects may be more important. Let us, therefore, look briefly at some of the effects of this drawdown.

Using the current model of Wairakei, a hot core of fluid, surrounded by, and in reasonable hydrologic contact with, cold water, the drawdown implies the development of a pressure gradient from outside to within the reservoir. This induces the inflow of the cold water. This inflow will (a) tend to stabilize the drawdown once a new mass balance is achieved, a situation we may be approaching today; and (b) extract heat from outer edges of the reservoir and sweep it in towards the production wells (Donaldson & Grant, 1981).

The above are both positive effects. The drawdown will, however, also be differential in the vertical and hence we will induce changes in the pressure profile and flow in any shallow two-phase zone. Grant & Horne (1980) show the change in pressure profile for Wairakei from approximately hydrostatic to approximately vapostatic in one zone due to the exploitation. The consequential effect of this is the commencement of flow down of cooler water. Thain (1980) remarked on this. Downward interzonal flows, of 150°C water, occurred in some production wells when they were temporarily shut in. They are probably occurring, undetected, in cracks and fractures in the formations. Drainage of water in the two-phase zone is now taken into account in some models of Wairakei (Fradkin et al., 1981).

This change in near surface flow due to the drawdown has two effects. First, cool water sinks to the liquid-water/steam-water interface in the system. If this were a general percolation this water would pick up heat on the way and thus sweep some of the heat from the upper layers of the reservoir. The indications are, however, that this flow may be channelled. In that event, the heat swept out would be limited and cooling would take place at depth.

The second consequence of the change of flow is at the surface. As has occurred in Wairakei, liquid-controlled surface manifestations will cease and steam-heated ones change. At the time of development of Wairakei, environmental changes of this nature were accepted with relatively little protest. Such is no longer the case today. Nor were the extent of the effects, now showing in Taupo, foreseen at the time Wairakei was developed.

b. Reinjection It is widely considered that reinjection of the cooled geothermal fluid may be the answer to the pressure drawdown problem. With good production-injection management it is thought that pressures may be maintained and the heat swept out of the rock more efficiently. In New Zealand reinjection is still regarded primarily as a waste disposal technique, although any side effects, such as pressure maintenance, would be very acceptable. The experience so far with reinjection in Japan (Horne, 1981) and our own experience with direct in-reservoir injection at Broadlands, suggests that return periods of the injected fluid are much less than the idealized theory would suggest. Energy recovery factors with in-reservoir reinjection may thus be much lower than those attainable by just allowing the cold fluid to flow in from outside the reservoir. Unfortunately, in the Broadlands area, we are having difficulty in finding sufficiently good permeability outside the reservoir.

There may also be other problems with reinjection in some fields. In a recent study, Grant (1981) has shown that reinjection of cool fluid into a hot two-phase zone may result in an additional drop in pressure, rather than a pressure recovery. The cool fluid must extract heat from the fluid in place and thus condense some of the steam. If the injected fluid temperature is below some "neutral" value the injected fluid volume will not make up the steam volume lost. Heat must then come from the rock and the temperature and pressure drop. In most real situations, the injected fluid temperature will be below the neutral temperature. Even with relatively poor mixing of the injected fluid, a proportion may, for example, move out along channels and hence not heat up in the two-phase zone, a pressure drop is likely.

c. Environmental Constraints When Wairakei was developed the waste water was discharged into the Waikato River and the gas fraction vented to the atmosphere. It was fortunate that the effects of this direct disposal of the geothermal effluents were as little as they have been.

Since that time the environmental regulations in New Zealand have been tightened considerably and to meet these we obviously have significant additional costs. Broadlands has been particularly bothersome in this regard due to the high non-condensible gas content of the fluid discharged. The H_2S is probably the most problematic fraction of this gas.

We have already discussed the environmental consequences of the pressure drawdown, i.e. the decay and modification of the surface activity.

d. Other Field Problems Exploratory/investigation wells were drilled in some of the other larger fields relatively early in our geothermal program. In both Waiotapu and Orakeikorako these investigation wells were not particularly successful. Donaldson & Grant (1978), for example, downgraded the potential of Orakeikorako due to the poor permeability found in the two wells drilled there. Nowadays, with our greater experience, we might choose different drilling sites, drill to different depths, or try stimulation. The low permeability of the first three wells at Ngawha did not deter us from continuing investigation.

Possible Reasons for Slow Development of our Geothermal Resources - (2) External Factors

There is no doubt that New Zealand's current energy surplus is a good reason for keeping the rate of geothermal electrical energy development down. The possibility of a restricted supply by the end of this decade, cannot, however, be disregarded. Obviously if a geothermal plant is to be a viable proposition in the early 1990's a field will need to be proven within the next few years. Only Broadlands, to be brought on line in the mid-to-late 1980's, is in that state at the moment.

Choosing the next site may not, however, be easy as, apart from the direct field development problems we have already discussed, there are other considerations that may need to be taken into account.

a. Tourism Tourism is now one of New Zealand's major industries. At the beginning of this decade about half a million visitors from overseas passed through our resorts. Current forecasts are for the figure to exceed 800,000 by the late 1980's. A large proportion of these tourists visit at least some of our thermal areas.

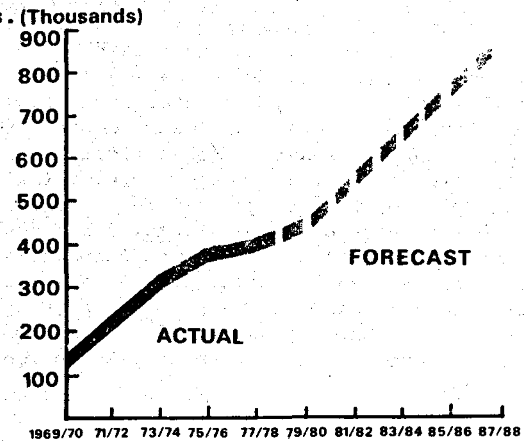

Fig. 4: Actual and estimated numbers of overseas visitors entering New Zealand 1969-1980.

In the Wairakei area, the development of the geothermal field quickly closed down the Geyser Valley tourist area, a water-controlled manifestation area adjacent to the Wairakei field, and ultimately resulted in the shutting down of the Karapiti blowhole area. It is to be expected that surface manifestations associated with any other exploited field would also ultimately deteriorate and die. Thus, tourism and energy development are in conflict.

The long term effect of this conflict is difficult to forecast. The major problem is that fields that are regarded as being the best tourist areas are also top of the list for energy. A high heat flow generally means more extensive (and interesting) surface manifestations. Low heat flow areas are naturally of less interest to the energy developers.

For development to date the conflicts have as yet been limited. Wairakei was spawned before we recognized the likely effects or their extent, and neither Broadlands nor Kawerau were sensitive areas. The investigation wells in both Orakeikorako and Waiotapu were also drilled early in the New Zealand geothermal development period, before water and other legal rights were required. In neither Ngawha, where the major attraction is a swimming pool complex, nor Mokai, an isolated area with little obvious activity, has there been problems getting these rights. In contrast, an investigation well at Ruahine Springs (Tikitere-Taheke) has been discussed for some time, but not yet scheduled, and a right was refused for a well some distance from Waimangu because there might be some effect. There is also considerable concern that withdrawal of water (and energy) in the Rotorua area for direct (non-electrical) use may be affecting features in Whakarewarewa Thermal Reserve, New Zealand's premier thermal tourist area.

b. Non-Electrical Uses of Geothermal Energy

For electricity production it is advantageous to have the fluid as hot as possible; for direct building and water heating cooler water will suffice. Thus, hot water in shallow aquifers and in areas of lower temperature is being tapped for such non-electrical uses. This water is also being used for tourism (swimming and spa pools), for agriculture and silviculture (drying, heated beds), and for industry. Higher temperature fluid, from deep wells, is also being used for industry. At Kawerau the steam is used in the pulp and paper processing; at Broadlands, for drying lucerne; and at Rotokaua, for extracting and processing sulphur.

It may be argued that such direct use of geothermal fluids is more efficient than the electricity production process and that, where this heat is available, it is bad energy policy to use electricity purely to produce heat. Non-electric uses of geothermal energy are, therefore, continually being sought. The low population base of the thermal area and the high cost of transportation of goods to our major centers do, however, work against these uses to some extent.

Conclusion The future of geothermal energy development in New Zealand is difficult to forecast. New Zealand is currently in an energy-rich state as far as electricity is concerned and it is anticipated that, even with the commissioning of several energy-intensive industrial plants, the demand will not catch up with the supply until the end of the present decade. Even then, geothermal energy will be competing with water-power as the source of supply of additional energy. While this water-power potential is still great, future development must take place in more difficult sites and be increasingly subject to consideration of protection of scenic areas, wild river sections, and other public domains.

As I have pointed out in this paper, geothermal energy development also has its problems: the drawdown of the reservoir and its side effects, the uncertainty of the benefits of reinjection, the necessity of cleanliness of the environment and the unproven production potential of undeveloped fields. These are all, however, scientific or engineering problems. Currently they are a challenge. Ultimately we will have the answers. The option between water- and geothermal-power may rest on the cost of the solutions at any time rather than whether there is a solution. It is my opinion that these problems and their solution will not restrain geothermal development in New Zealand in the long term.

It is also my opinion that the conflict between tourism and energy development for each field will also be resolved. In some cases there will be no problem, energy development will affect very little, or total protection for tourism (or for the unique nature of the area or something in it) is essential. In other cases a "political" choice must be made. In a few cases, and I am hopeful that Rotorua may be in this category, it may be possible to extract some energy and still protect the manifestations in the tourist park.

Ever since the first moves were made to study Wairakei with the serious objective of development (in the early 1950's), New Zealand has maintained its geothermal team of scientists and engineers. I am confident that it will continue to do so. I am also confident that development of our resources will continue, although I cannot guarantee that they will all be used for the production of electric power.

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STATUS OF GEOTHERMAL ELECTRIC POWER IN ICELAND 1980

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INTRODUCTION

The main utilization of geothermal energy in Iceland is for thermal applications. There are many geothermal district heating systems that supply hot water to residential, commercial and industrial buildings. Geothermal water and steam are also used in greenhouses and for processing purposes in industry. The generation of geothermal electric power in Iceland is, however, limited because most of the electricity demand is met with hydro-power of which the country is relatively well endowed with. Until early this century, the use of geothermal energy in Iceland was limited to individual hot springs for bathing and washing. In 1928 drilling for geothermal energy in Iceland started. This was in a low-temperature field in Reykjavík where several shallow wells were drilled producing in total 15 l/s of 90-100°C water. Two years later in 1930 this water was piped 2.8 km to supply heating for about 70 homes, one school and a swimming pool. Since then great developments have taken place and now geothermal district heating plays a very important role in the economy of Iceland.

At about the same time as geothermal district heating was being introduced in Iceland, the generation of electric power using geothermal steam was already under discussion. In 1944 the first steam driven engine with a generator was installed in a high-temperature geothermal field in Iceland. This was near Hveragerdi, in the Hengill area, where several shallow boreholes had been drilled and were being used for various purposes. This first steam engine-generator was only run for a short time and produced sufficient electricity for just a few light bulbs. In 1946, also in Hveragerdi, the first steam turbine system was installed capable of generating 35 kW of electricity. This demonstration unit operated only for about one year until a much larger diesel generator was installed.

In this paper the development and status of geothermal electric power in Iceland will be discussed. Non-electrical applications will only be mentioned in passing.

RESOURCES

The geothermal areas in Iceland have traditionally been divided into low- and high-temperature areas. The high-temperature areas are in the active volcanic zone lying south-west to north-east across Iceland and the low-temperature areas on both sides of it. The two main low-temperature areas are in the south and west of Iceland at the periphery of the active volcanic zone, but other such areas are widely distributed. In the low-temperature areas the temperature of the reservoir fluid in the uppermost 100 m does generally not exceed 150°C while in the high-temperature areas it does and is usually 200°-350°C. It should be remembered that the water produced in low-temperature areas in Iceland is used in thermal applications only, being the back-bone of the district heating industry.

When it comes to the generation of geothermal electric power in Iceland, the high-temperature areas have to be used. There are 19 known high-temperature areas in Iceland and 9 potential areas. Figure 1 shows a map of Iceland and the location and name of these 28 high-temperature areas, most of which are within the active volcanic zone. Several geothermal assessment studies of the high-temperature areas have been conducted. The most comprehensive and recent is that of Pálmason (1981) and co-workers at Orkustofnun (Energy Authority). The study is based on the same methodology as used in the United States and Italy, but with several modifications to suit geological conditions in Iceland. The total size of all the high-temperature areas is about 600 km^2. An accessability factor of 0-1 was assigned to each of the 28 areas, the average value being about 0.6 for the 600 km^2. To arrive at an estimate of the electric power which the areas could possibly produce, it was assumed in the assessment study, that 20% of the accessable thermal energy of rock and water above 130°C down to a depth of 3 km is recoverable. This thermal energy is then converted to electricity with an efficiency of about 7-9% depending on the known or expected temperature of the fluids produced. It was estimated that 3,500 MW-electrical could be produced in total for a period of at least 50 years. About 3,000 MW-electrical would be in the 19 known high-temperature areas.

The hydro-power potential of Iceland has recently been up-dated by Tómasson (1981) and co-workers at Orkustofnun. The main result of this assessment is that the usable capability amounts to about 64 TWh/year with an associated installed capacity of 7,300 MW hydro-power. This usable electricity was divided into four groups that range from the most economical to marginal. In the decades to come the large hydro-schemes in the highlands (first group) will be most economic with a generating capability of about 30 TWh/year or almost 1/2 the total hydro-power potential of the country. The associated installed capacity corresponds to about 3,400 MW-electrical.

The total available geothermal electric power in Iceland may therefore amount to 3,500 MW for 50 years, while the hydro-power potential has been estimated more that double that value or 7,300 MW. When considering that hydro-power is more renewable than geothermal energy, which must also be viewed as higher risk technology, it seems most likely that the former will continue to supply the bulk of the electricity required in Iceland.

UTILIZATION

The energy market in Iceland is in many respects unusual when compared to many other countries. The main reason for this is the large amount of geothermal water sold for space heating purposes. In the last decade the percentage of Icelanders enjoying geothermal district heating has increased from about 40% to 70% (Gudmundsson 1976, Gudmundsson & Pálmason 1981). Another feature of the market is that for many years almost half the total energy consumption has been imported petroleum products, although the country has relatively great hydro-power and geothermal energy resources. Iceland is a sparsely populated country with about 230,000 people living in an area of 130,000 m^2. Most towns and villages are located on the coast with about half the population living in the south-west of the country in the Reykjavík area.

An overview will now be given of the electrical energy industry in Iceland in 1980. The total production of electricity amounted to 3,243 GWh of which 3,053 GWh or 97.2% was from hydro-power stations. Geothermal electric power stations produced 45 GWh (excluding own use) and oil-fired and diesel stations also 45 GWh. More that half the electricity was used in energy intensive industries and the rest for general purposes. At the end of 1980 the installed generating capacity of all public power stations was 670 MW of which 542 MW was hydro-power, 12 MW geothermal and 116 MW oil-oil-fired or diesel. The above geothermal value refers to the actual generating capacity but not the rated capacity at the end of the year (see later).

A few words about fuels imported to Iceland in 1980. The total fuel use amounted to 542,083 tonnes being 10.4% less than in 1979. Of this 43% was diesel fuel for fishing vessels mainly, but also for space heating, industrial use, transportation and the generation of electricity in small diesel stations. Heavy fuel was 32% being used for trawlers with large engines and also for industry. Gasoline for motor transport amounted to 16% while jet fuel, aviation gasoline and kerosene added up to 9%.

More details will now be given about the geothermal energy market in Iceland in 1980. Figure 2 shows the utilization of geothermal energy in Iceland. At the end of 1980, high-temperature geothermal energy was used in four areas in Iceland, excluding small experimental units. Table 1 shows these high-temperature geothermal areas and the main details. For each area there is shown the number of boreholes drilled and how many are capable of production. The thermal power is divided into installed and used. The former represents the maximum thermal power which the production boreholes are capable of delivering at present back pressures or lower. This thermal power is calculated on the basis of condensing all the steam and cooling the total borehole discharge (steam and water) to 100°C. The used thermal power, on the other hand, is the actual thermal power consumed in the relevant direct application. At Svartsengi it is the maximum thermal power consumed for space heating, in Hengill it is the thermal power used for space (10 MW) and greenhouse (15 MW) heating in Hveragerdi, while the Námafjall application is for industrial drying. The last column in Table 1 shows the rated (or name-plate) capacity of the 3 geothermal electric power stations in Iceland. The geothermal steam used for these power plants is included in the installed thermal power shown in the table.

It is of interest to estimate the thermal power associated with all direct applications in Iceland. Gudmundsson & Pálmason (1981) have reported the utilization of low-temperature geothermal fluids in Iceland and the rest of the world. Experience in Iceland shows that low-temperature waters used for space heating are discharged at 35-40°C on average. Table 2 shows the total thermal power used in direct applications from low- and high-temperature geothermal areas in Iceland in 1980. The reference temperature is taken as 35°C, amounting to 818 MW-thermal. The steam used in electric power generation is not included in this tabulation. The main use is space heating, being 85% of the total. Assuming a load factor of 50% the amount of thermal energy used in direct applications becomes about 13,000 TJ or 3,600 GWh in 1980.

DEVELOPMENT

Extensive geothermal studies and drilling were carried out in the 1950's in the Hengill and Krísuvík high-temperature geothermal areas in the south-west of Iceland. In 1950 a pre-feasibility study had been carried out for a 30 MW geothermal electric power plant to be located near the town of Hveragerdi in the Hengill area. It was estimated that the geothermal electricity would cost 40-50% more to produce than in a similar sized hydro-power station. Subsequently it was decided to build a second hydro-power station in the river Sog to serve the electricity market of the south-west of Iceland, particularly Reykjavík.

Great advancement was made in the exploration and exploitation of geothermal energy in 1958 when a rotary drilling rig, with a depth capability of 2000 m, was brought to Iceland. In the years that followed it was e.g. used to drill 8 boreholes 800-1200 m deep near Hveragerdi. By 1961 the project design of a 15 MW (net output) geothermal electric power plant was completed (Einarsson 1961). It was concluded that the capital cost per installed kW was similar to that of hydro-power stations in Iceland of under 40 MW in output. The generation cost of electricity from both types of stations was considered comparable. These plans to build a small geothermal power station were pushed aside in 1965-1966 when it was decided to build a 210 MW hydro-power plant at Búrfell in the river Thjórsá. Simultaneously an agreement was signed with an international aluminium company to build a large smelter not far from Reykjavík. Further work on the Hveragerdi project was abandoned. Additional reasons for the lack of interest in the Hveragerdi scheme, were problems of both geothermal and technical nature. The enthalpy of the steam-water mixture produced in the boreholes was rather low, corresponding to a reservoir temperature of about 215°C. This meant that a large quantity of steam and water had to be produced to generate the electricity, resulting in a disposal problem. This, and expected calcium carbonate deposition in the boreholes, did not favour building a power plant near Hveragerdi. The interest in geothermal electric power in Iceland was, however, aroused again when temperatures of 260-280°C were encountered when drilling in the Námafjall high-temperature area 1965-1966.

There are now 3 geothermal electric power plants in Iceland. These are at Námafjall and Krafla in the north-east and at Svartsengi in the south-west. The Námafjall and Krafla stations are not far from each other, only 7-8 km. The Svartsengi station is on the Reykjanes peninsula where there are several high-temperature areas.

NÁMAFJALL

The development of the Námafjall high-temperature area has been described by Ragnars et al. (1970). Drilling in the west section of the Námafjall area was started in 1963 and in 1966 the first production well was drilled. It supplied steam to the diatomite processing and drying plant that was commissioned in late 1967. At that time a pre-feasibility study indicated, that building a 5-10 MW non-condensing geothermal electric power station in Námafjall, would be an attractive way of meeting the increased load in the north-east part of Iceland, in smaller steps than would be economically feasible in hydro-power stations. An important consideration at that time was also the felt need of gaining experience in operating a geothermal electric power plant. In 1968 it was decided to build a small atmospheric exhaust plant in Námafjall and in 1969 it became operational. By 1971 enough steam had been secured for both the power plant and the diatomite plant and then onwards the Námafjall station was in full operation.

The main technical specifications of the Námafjall (and Krafla and Svartsengi) geothermal electric power station are presented in Table 3. The turbine-alternator is a British Thompson Houston (BTH) industrial set built in 1932. It was bought second-hand, but some alterations were made on it in 1968 when it was installed. The steam turbine itself is of the simplest possible type with one Curtis wheel. In 1971 the wheel was replaced with a new one to increase the output and to change the material of construction to make it more suitable for geothermal steam. The rated capacity is now 3 MW and the material used 12-14% Cr-steel. Every year some silica deposits have to be cleaned from the inlet nozzles of the steam turbine. This has been caused by some carry-over of water from the steam-water separators. After almost a decade of operation, the condition of the steam turbine at Námafjall is good. There has been some pitting corrosion and erosion of the first row of blades, but not serious.

Ten boreholes had been drilled in Námafjall by the end of 1975. They ranged in depth from 340 to 1800 m and were spaced at about 100 m apart. At that time wells 4-9 were productive. In 1979-1980 two more boreholes were drilled. By then most of the older boreholes had been destroyed due to tectonic activity. It appears that magma from the fissure swarm extending from Krafla to Námafjall caused the increased surface activity. At the end of 1980 two new wells (11 and 12) produced high-pressure steam for the diatomite plant and the Námafjall power station. Borehole 11 produced 29 kg/s at 19 bar-g pressure of steam-water mixture with an enthalpy of 2400 kJ/kg. Borehole 12 produced 22 kg/s at 16 bar-g pressure of steam-water mixture with an enthalpy of 2300 kJ/kg. Borehole 4 is the only old well that still produces. In total it is capable of producing about 10 kg/s of steam-water at enthalpy close to 1000 kJ/kg. The steam from this borehole is used to heat directly fresh water for district heating in the Reykjahlíd village by Lake Mývatn. Table 4 shows the estimated gas composition of the saturated steam produced from borehole 11 in Námafjall (N-11) when allowed to flash down to 180°C or 10 bar-g pressure. The total gas content is estimated as 0.2% by weight.

The steam-water mixture from the boreholes is piped in two-phase flow to two cyclonic separators. These have (safety) valves that are adjusted to open if the pressure increases above the operating pressure of 11-12 bar-g. In this way the excess steam produced is vented to the atmosphere. The separated water is discharged to concrete silencers and to a surface pond where it percolates into the ground.

KRAFLA

The Krafla Power Station is the first major geothermal electric power project in Iceland. Exploration of the Krafla high-temperature area was initiated in 1970. This work was not done with any specific utilization in mind, but in 1972 a preliminary project report was published by Orkustofnun on the feasibility of constructing a 8 MW, 12 MW or 16 MW geothermal electric power plant in either Námafjall or Krafla. The results were considered sufficiently encouraging to warrant further study and in 1973 a feasibility report was again published by Orkustofnun on the above sized stations and also a 55 MW station.

By late 1973 it was considered that the electricity supply situation in north-east Iceland would shortly become critical because a planned hydro-power scheme in the river Laxá had to be restricted for environmental reasons. The preliminary and tentative plans for a geothermal electric power station in Námafjall or Krafla were therefore suddenly the subject of great interest. In 1974 the construction of a 55 MW power plant to be located in Námafjall or Krafla was authorized and an ad-hoc committee was formed by the Ministry for Industry (and energy), known as the Krafla Project Executive Committee. The committee was to be responsible for the construction of the power plant, while the State Geothermal Steam Supply at Orkustofnun was to develop the field and produce the steam. The State Electric Power Works were given the responsibility of building the switchyard and the 132 kV transmission line to the town Akureyri. Formally, all the organization involved reported to the Ministry for Industry. The events that followed developed differently than imagined and the Krafla geothermal power project became one of the most controversial issuesin Iceland for years.

The first issue that had to be resolved was to decide where to build the power plant. The Námafjall area was already well known, but no drilling had yet been done in Krafla. The State Drilling Contractors at Orkustofnun were contracted to drill two 1200 m deep exploration boreholes in 1974 and the Geothermal Division of Orkustofnun was engaged to carry out the geoscientific work. In 1975 the Geothermal Division reported on the exploration drilling and concluded that the Krafla geothermal field would be able to produce the required amount of steam for a 50-60 MW power station. Because the Krafla geothermal area is much larger than Námafjall area, the former was favoured as the site for the power plant. It was also the view of the Environmental Protection Board of Iceland that the Krafla site would be a better choice. It was subsequently decided to build the proposed power station in Krafla. Reporting the drilling history and exploration of the Krafla geothermal field requires more space than is available here. Stefánsson (1981) has made a report on the development and status of the project in late 1978. Stefánsson & Benediktsson (1980) have also reported on the geothermal fields in Krafla and Námafjall. Three boreholes (1300-200 m deep) were drilled in the summer of 1975, six (1300-2200 m deep) in 1976, one (2200 m deep) in 1978 and three (2000-2100 m deep) in 1980.

The power station in Krafla was built by the Krafla Project Executive Committee. Table 3 shows the main technical specifications of the station. The station was to have two 30 MW turbine-generators, but only one of them has been installed. The station has never operated on full load because sufficient high-pressure steam has not been available. Its maximum load was initally 6-8 MW but has now reached 11-12 MW. Elíasson et al. (1980) have reported in detail about the Krafla Power Station. The station was commissioned in early 1978.

The flow diagram for the one 30 MW unit of the Krafla Power Station is shown in Figure 3. The steam-water flow from the boreholes is piped in two-phase flow to the separator building which contains all high-pressure and low-pressure separators for one unit. The high-pressure separators operate at 8.7 bar-a pressure. The high-pressure steam is manifolded from the separators into a single pipeline which brings the steam to the power station. A second flash steam separator is used to boil off and separate all the water from the high-pressure separator at a pressure of 2.2 bar-a. The primary steam enters the turbine at 7.2 bar-a pressure and the secondary steam at 2.0 bar-a pressure between the second and third stages. The turbine is a single-cylinder, double-flow, dual-admission unit with 5 stages. It is manufactured by Mitsubishi Heavy Industries (MHI) in Japan. It has an underlying direct contact jet condencer operated at 0.12 bar-a. The high-pressure steam contains 1.5-1.7% of non-condensable gases at the present time.

At the end of 1980 eight boreholes of the 15 drilled could produce steam as shown in Table 1. Most of these are located within 500 m of the separator station, spaced 100-300 m apart. The high- and low-pressure steam are piped to the power station about 500 m from the separator station. The total production of the field in late 1980 was 168 kg/s of steam -water from 11 boreholes of which 88 kg/s came from the 8 that were connected with pipelines. The 4 boreholes not producing were either damaged or not completed. The enthalpy of the steam-water mixture discharged from the 8 boreholes utilized is in the range 1100-2900 kJ/kg. These boreholes produce in total 53 kg/s of high-pressure steam (8.7 bar-a in separator) of which about 1/2 comes from only two boreholes. Table 4 shows the estimated concentration of non-condensables when the steam-water mixture from these two boreholes (K-9 & K-14) is allowed to flash at 175°C which corresponds roughly to the separator pressure of 8.7 bar-a. The gas content is about 1.9%, which is an order of magnitude greater than in Námafjall and Svartsengi.

In December 1975 a volcanic eruption occurred about 2 km away from the Krafla Power Station. This volcanic eruption was the beginning of a rifting episode in the fissure swarm intersecting the Krafla caldera. During the last 5 years this volcanic activity has continued with 12 rifting episodes, 6 of which have resulted in volcanic eruptions. The magmatic activity has influenced the production characteristics of the Krafla geothermal field and given rise to several difficulties experienced in its utilization. Volcanic activity is still going on in the Krafla area affecting the boreholes and reservoir proparties in both the Krafla and Námafjall geothermal fields.

SVARTSENGI

The exploration of the Svartsengi high-temperature geothermal area started more than 10 years ago. The first two boreholes were drilled in 1971-1972 and it was discovered that the hot water produced was saline with a concentration about 2/3 of seawater. The reason for exploration work in the Svartsengi area was the possibility of building a heating system for the nearby town of Grindavík.

The exploration and early drilling in Svartsengi were successful, but the problem was that the high-temperature brine could not be used directly for district heating purposes. It was clear that a novel method had to be developed if the high-temperature brine was to be used for district heating. Extensive pilot plant studies were carried out to test several methods of heating fresh cold water using the geothermal steam-brine mixture produced in Svartsengi. Arnórsson et al. (1975) have reported some of the early results.

As the Svartsengi project was developing from exploration to pilot-plant studies, the price of oil suddenly quadrupled. At the turn of 1974/1975 a company was formed to exploit the Svartsengi high-temperature field for district heating in the Sudurnes region, which consists of seven separate towns and villages on the Reykjanes peninsula. The main function of the power plant in Svartsengi is therefore the production of hot water for district heating.

The novel heat exchange process used in the Svartsengi power plant has been described by Thórhallsson (1979). The flow diagram of the power plant is shown in Fugure 4, illustrating the main equipment and associated flowrates, temperatures and pressures. There are four parallel flow streams in power plant I. Two of these are as shown while two have additional heat exchangers that can cool the deaerated water from about 100°C to 85°C. This water is pumped directly to Grindavík while the 125°C water is pumped (in the opposite direction) to the rest of the towns using the hot water.

The geothermal steam-brine mixture is piped in two-phase flow from the wells to a flash plant located by the power house. (See Figure 4). Two centrifugal steam separators in series produce the high-pressure (5.4 bar-a) and low-pressure (0.25-.039 bar-a) steam. The water level in the high-pressure separator is controlled and the spent brine discharged from the barometric leg of the low-pressure separator is presently discharged into a large pond by the generation of electricity in a back-pressure turbine before being condensed in a plate heat exchanger. The low-pressure steam is piped to a direct contact condenser where it heats the fresh cold water from 5°C to 65°C and removes 90% of the dissolved gases from the fresh water. This water is pumped, in two of the flow-streams, to the turbine condenser mentioned above. In the other two flow-streams there is the possibility of pumping the water first through heat exchangers as mentioned above to produce 85°C water for the town of Grindavík. In the turbine condenser the water is heated to 105-110°C before it enters the atmoshperic deaerator. At this point the hot water is heated further by high-pressure steam in a plate heat exchanger to 125°C for pumping to the main district heating market in the area of the town of Keflavík.

The design of power plant I is based on a steam-brine production of 60 kg/s from each borehole, an output which is split between two flow-streams. The power plant has four flow-streams such that two boreholes are required on-stream at any one time. Each flow-stream produces sufficient hot water to satisfy a 12.5 MW thermal load at the consumer, the rated capacity of the power plant therefore being 50 MW thermal.

Power plant II is presently under construction. It is being built for the purpose of supplying district heating water to the Keflavík International Airport and NATO Military Base. Initially it is to have 2-3 flow-streams of a new design, each with a rated thermal capacity of 25 MW.

There are two AEG-Kanis 1 MW back-pressure steam turbines in power plant I. Table 3 shows their main technical specifications. The amount of steam expanding through the turbine in Figure 4 is sufficient to generate about 0.6 MW of electricity. The high-pressure steam associated with two flow-streams in power plant I is used for each turbine-generator. The first 1 MW turbine was commissioned in late April 1978, the second one in 1979. Both units have operated as required since that time. The main purpose of these turbines is to provide the power plant with electricity for pumps and other equipment. In December 1980 the third turbine-generator was installed in Svartsengi, a 6 MW Fuji Electric package-type unit (see Table 3). The unit is located in power plant II and generates electricity for general demand in the Sudurnes region.

At the end of 1980 ten geothermal boreholes had been drilled in Svartsengi (see Table 1). The boreholes are of three basic designs: a) 2, 3 and 10 are shallow 239 m, 402 m and 424 m closely spaced 35-105 m, b) 4, 5 and 6 are deep 1713 m and 1734 m with 9 5/8" production casing and c) 7, 8, 9 and 11 are deep 1438 m, 1603 m, 994 m and 1141 m with 13 3/8" production casing. All boreholes have slotted liners except 7 which is "barefoot". Boreholes 5-11 are spaced 200-250 m apart while 2, 3 and 10 are much closer to each other. The output of the boreholes with 9 5/8" production casing is 60 kg/s but the 13 3/8" boreholes have an output of 120 kg/s.

Flowrate (and enthalpy) measurements have been done on all the Svartsengi boreholes. Figure 5 shows some of the results. Borehole S-4, being 9 5/8", produces 60-80 kg/s at 10-15 bar-a well head pressure, while S-8 and S-11, being 13 3/8", produce 120-180 kg/s. Well S-10, shallow 13 3/8", is capable of similar production as the other wide holes. Borehole S-7, which is "barefoot", has typical 13 3/8" characteristics but has been tested to only 80 kg/s. The large diameter boreholes in Svartsengi are probably among the best producers in the world. The enthalpy of the steam-brine mixture in all the boreholes corresponds to water at 235-240°C. It has remained constant since the start of production as has the fluid composition.

There has been experienced calcium carbonate deposition in some of the boreholes in Svartsengi. These deposits are formed at the depth where flashing starts and have to be cleaned every 7-8 months with a drill-rig. It was partly because of the calcium carbonate problem that it was decided to drill wider boreholes and use 13 3/8" production casing instead of the 9 5/8". Of the 10 production boreholes drilled in Svartsengi, one has suffered casing failure and is no longer useful as a production hole.

The amount of non-condensable gases in Svartsengi is low being typically 0.1-0.3% wt. Table 4 shows the estimated non-condensable content in high-pressure steam produced in borehole 6, when the steam-brine mixture is separated at about 155°C (5.4 bar-a), which corresponds to normal operating conditions.

DRILLING

The boreholes drilled in Námafjall 1979-1980 are similar to the most recent wells drilled in Krafla. Ragnars & Benediktsson (1981) have described the drilling of a typical 2000 m deep borehole in Námafjall. They have also given the actual cost of drilling well 11 in Námafjall in the middle of 1979. The borehole is 1923 m deep, cased with 13 3/8" to 280 m and 9 5/8" to 620 m. The 7" slotted liner extends to the bottom. The drilling time was 33 days and the total cost 702,700 U.S. dollars or 265 $/m. The drill-rig used was a Gardner Denver 700E. It must, however, be appreciated that the total drilling cost can vary appreciably between geothermal fields. The boreholes drilled in Krafla are more expensive than in Námafjall, with a total cost of almost one million U.S. dollars. It takes longer time to drill in Krafla because the conditions there are more difficult.

In the south-west of Iceland in Svartsengi, the boreholes are less expensive than in Námafjall and Krafla. Borehole 8 in Svartsengi is typical for the deep wells with a 13 3/8" production casing. It was drilled to 1603 m in 1979 and cost about 650,000 U.S. dollars or 350 $/m. The drilling time was 35 days and the drill-rig used was Oilwell 52. The 13 3/8" production casing is to 600 m and the 9 5/8" liner to bottom.

ENVIRONMENT

The utilization of high-temperature geothermal energy in Iceland is both limited and recent in comparison to low-temperature waters. In the 12 years since the first major utilization of high-temperature geothermal energy started, there have not been any significant environmental problems. There has, however, been expressed concern over topographical and visual matters.

In Námafjall and Krafla the boiling water from the separators is discharged into a disposal pond and a small stream, respectively. The hot water percolates into the highly fractured lava and mixes with the ground water. There are no indications that the disposal water causes environmental problems.

At Svartsengi there is, however, a disposal problem of a sort. The geothermal brine from the low-pressure separators is highly supersaturated with silica which polymerizes quickly to form colloidal silica that deposits in the disposal pond. The silica particles gradually seal the surface lava when percolating into the ground, with the result that the disposal pond increases relatively rapidly in size. In the future the plan is to reinject the waste brine and condensate and presently work is underway to bring that about. Other work at Svartsengi relevant to environmental matters are detailed studies of ground-water hydrology, land subsidence (levelling and gravity measurements) and seismicity. Similar studies are carried out in the Krafla-Námafjall region.

CONCLUSION

In this paper the development and present status of geothermal electric power in Iceland have been discussed. The main "competitor" of geothermal electric power in Iceland is the relatively abundant and cheap hydropower, while geothermal energy has no "rival" when it comes to thermal applications such as district heating. In the years to come the role of geothermal energy in electricity generation is not clear. Because of the Krafla experience there is limited confidence in Iceland in geothermal electric power.

The success at Svartsengi has, however, done a lot of good for the geothermal industry in Iceland. It was provided the counterbalance to Krafla and shown that high-temperature geothermal energy is viable and that Námafjall is not the exception. The novelty of the Svartsengi power plant has created great interest and for the first time in Iceland there has been generated electricity and thermal power in the same plant. Co-generation will undoubtedly be widely practiced in the geothermal power and processing plants built in the future.

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TABLE 1

High-temperature geothermal energy used in Iceland in 1980.

Name of area	Boreholes		Thermal power (MW)		Electric Power
	Drilled	Production	Installed[a]	Used	(MW)
Svartsengi	10	9	520	50[b]	8
Hengill	>25	19	135	25[b]	0
Námafjall	12	3	100	35[a]	3
Krafla	15	8	140	0	30
Total	>62	39	895	110	41

a: Above 100°C condensate.
b: Space heating above 35-40°C.

TABLE 2

Approximate thermal power used in 1980 in Iceland from low- and high-temperature geothermal areas. The steam used for geothermal electric power generation is not included in this tabulation.

Type of use	Thermal power >35°C (MW)			(%)
	Low	High	Total	
Space heating	634	60	694	84.9
Greenhouses	36	15	51	6.2
Swimming pools	21	0	21	2.6
Industrial	15	35	50	6.1
Fish culture	2	0	2	0.2
Total	708	110	818	100.0

TABLE 3

Main technical specifications of geothermal electric power stations in Iceland (Thórhallsson et al. 1979).

Specification	Námafjall	Krafla	Svartsengi	Svartsengi
Manufacturer	BTH	MHI	AEG-KANIS	Fuji
Installed (year)	1968	1978	1978/1979	1980
Rated capacity (MW)	3	30	2 x 1	6
Speed (rpm)	3000	3000	4479	3000
Inlet pressure (bar-a)	9-10	7.2/2.0	5.4	5
Steam flowrate (kg/s)	~14	53.2/19.6	8.9	37.2
Exhaust pressure bar-a)	~1.1	0.12	1.7	1.2
Type/Stages	C	5	C	C

TABLE 4

Estimated non-condensable gas composition in geothermal steam
(Compiled by G. Gíslason & T. Hauksson).

Concentration (mg/kg)	Námafjall	Krafla	Krafla	Svartsengi
Borehole number	N-11	K-9	K-14	S-6
Date of sample	20.09.80	25.11.80	28.11.80	15.05.80
Enthalpy mixture (kJ/kg)	2,355	1,055	2,634	1,030
Steam fraction	0.79	0.15	0.93	0.18
Temperature[a] (°C)	180	175[b]	175[b]	155
CO_2	799	18,080	11,660	2,540
H_2S	1070	642	751	34.5
H_2	93	6.4	35.9	0.03
CH_4	1.17	6.6	0.84	0.50
N_2	5.8	0.0	0.0	33.6
Total	1,969 (~0.2%)	18,735 (~1.9%)	12,448 (~1.2%)	2,609 (~0.3%)

a: Temperature corresponding to saturation pressure of steam-water separation.
b: Separators are presently operated at 6-7 bar-a but not the design pressure 8-9 bar-a.

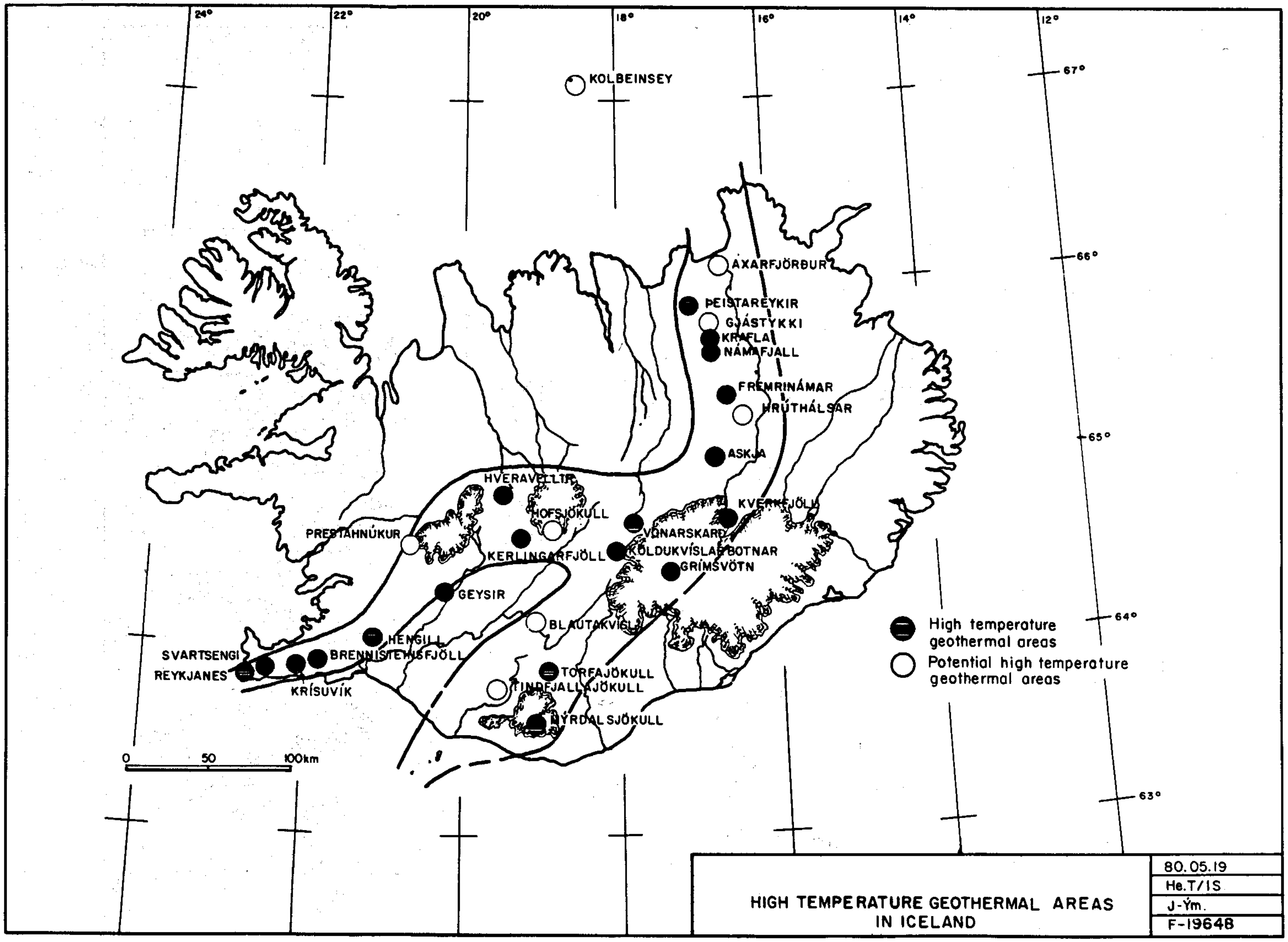

FIGURE 1. High-temperature geothermal areas in Iceland, known and potential.

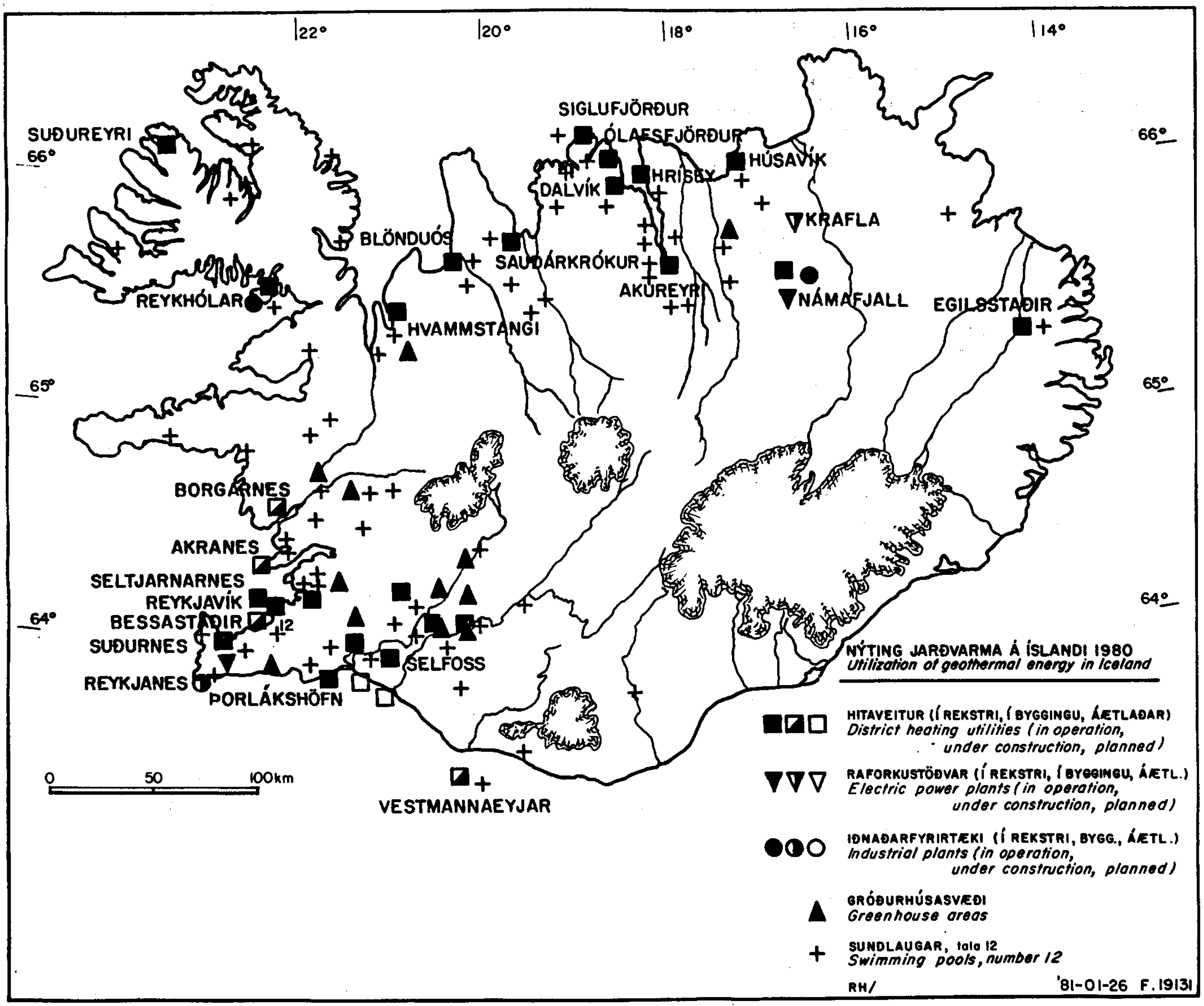

FIGURE 2. Utilization of geothermal energy in Iceland in 1980.

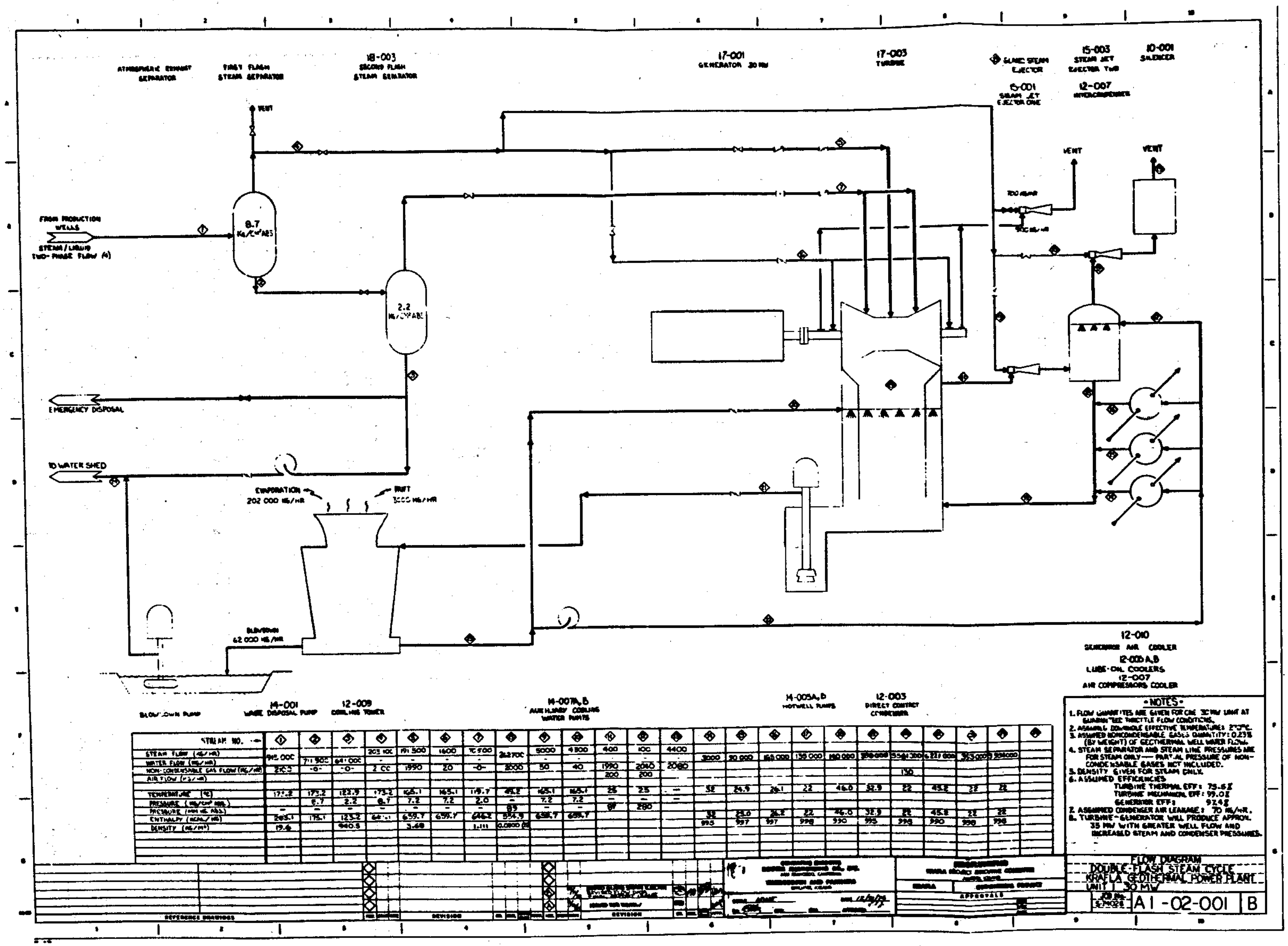

FIGURE 3. Flow diagram for one 30 MW unit in the Krafla Power Station.

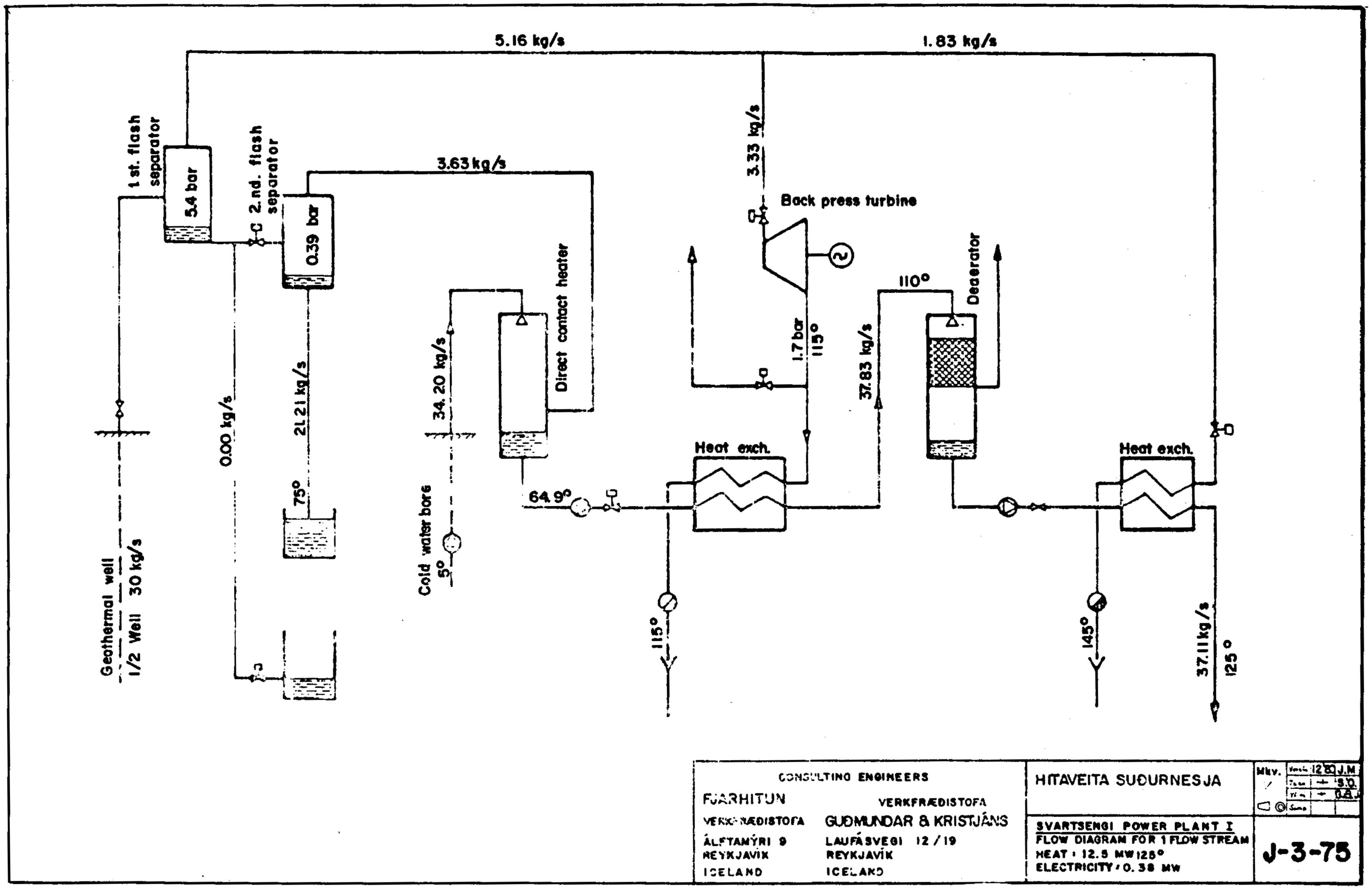

FIGURE 4. Flow diagram for one flow stream (12.5 MW-thermal) in the Svartsengi power plant.

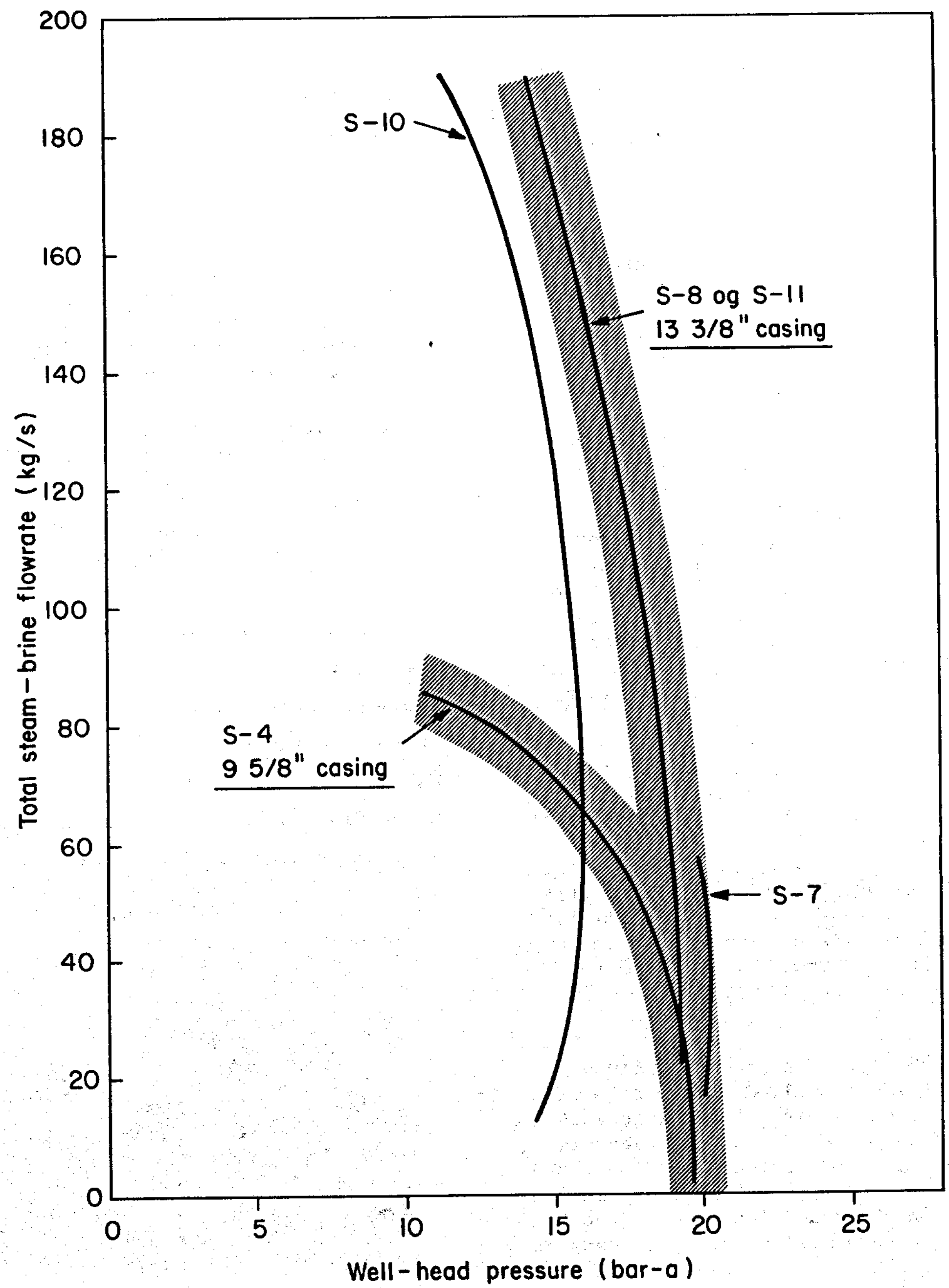

FIGURE 5. Flowrate measurements of boreholes in Svartsengi.

PROGRESS IN GEOTHERMAL POWER DEVELOPMENT

IN THE AZORES, THE PEOPLE'S REPUBLIC OF CHINA,

COSTA RICA, EL SALVADOR, INDONESIA, KENYA,

TURKEY, AND THE U.S.S.R.

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Abstract The combined installed geothermal electricity generating capacity for these eight countries as of June 1981 is 113.7 MW. Only Costa Rica and Kenya do not yet have operating plants, but each is moving ahead with plans to install plants at promising fields. Wellhead units are operating successfully in the Azores, Indonesia, and Turkey, and plans are in motion to install larger units in the last two countries mentioned. The Ahuachapán field in El Salvador has reached its design limit (95 MW), and attention is now focussed on another highly promising site, Berlín, where a 55 MW double-flash plant is scheduled for operation in the mid-1980's. The Soviet Union has expanded its plant at Pauzhetka from 5 to 11 MW, and is considering several other sites for possible new geothermal plants.

The Azores (Portugal) A significant geothermal anomaly has been confirmed in the Ribeira Grande area in the central portion of the island of São Miguel. Reservoir temperatures exceed 200°C (392°F) with temperature gradients of 40-90°C/100 m (22-49°F/100 ft) and extremely low resistivities (∿1 ohm·m). The geothermal area is estimated to cover an area of 8-10 km^2 (1980-2470 acres) and to hold the promise of 200-400 MW for 30 years (1).

In October 1979, a 3 MW portable turbine-generator unit was installed at the site of a single well. Table 1 gives the particulars for the unit (2). A photograph of the plant is given in Fig. 1. The turbine, generator, and auxiliaries are contained within a single housing; the inlet steam line enters from the left, and the exhaust silencer can be seen at the rear (Fig. 1).

It is possible that the geothermal resource could become the center of an energy park where multiple use would be made of the hot water and steam. Besides electricity, the resource could provide refrigeration and air conditioning for the island's fishing industry, energy to supply greenhouses for a variety of agricultural applications, and direct heat for a number of commercial and residential complexes as well as for health spas (1).

Table 1 Technical specifications for wellhead unit on São Miguel (2)

Turbine type......	Single cylinder, single impulse (Curtis) stage, back-pressure
Rated capacity....	3,000 kW
Maximum capacity..	3,750 kW
Speed.............	3,000 rev/min
Steam pressure....	392 kPa (56.8 lbf/in^2)
Steam temperature.	142.9°C (289.2°F)
Exhaust pressure..	103 kPa (14.9 lbf/in^2)
Steam flow rate...	56.5 t/h (124,526 lbm/h)
Maximum pressure..	1568.6 kPa (227.5 lbf/in^2)

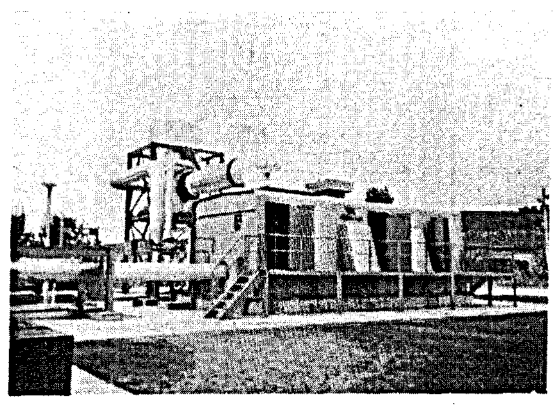

Fig. 1 Wellhead unit on São Miguel, The Azores. (Photo from MHI, Ltd., Japan.)

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The People's Republic of China A detailed discussion of China's geothermal power plants has been given elsewhere (3). While research and development continues at several small experimental plants using quite low-temperature geothermal fluids (67-91°C, 153-196°F), the main effort is now concentrated on the high-temperature field at Yangbajing, 90 km (56 mi) northwest of the city of Lhasa in the Tibet Autonomous Region. A wet-steam field with fluid temperatures of about 150°C (300°F) extends over an area of roughly 10 km^2 (2470 acres) at an elevation of 4,300 m (14,110 ft) above sea level. About 20 wells have been drilled to supply steam to three power plants (4). One of these, a 1,000 kW unit, has been operating successfully since 1977 and was described earlier (3). Two new buildings are under construction to house the second and third units, each of which will be 3,000 kW in capacity. The new units are expected to begin operating during 1981 (Personal communication, Dr. Zhi-jian Wu).

Costa Rica An outstanding liquid-dominated prospect has been confirmed at Miravalles in the Guanacaste Province of Costa Rica. The site lies on the southwest flank of the Miravalles Volcano, just north-northeast of the village of La Fortuna. Reservoir temperatures of between 230-240°C (445-465°F) have been revealed by three full-size exploratory wells, all of which struck production zones. These wells, designated PGM-1,-2, and -3, are of stepped-diameter construction with 660 mm (26 in) initial hole diameter ending with a 216 mm (8.5 in) hole; the surface casing is 508 mm (20 in) in diameter, and 194 mm (7.625 in) slotted liners are used in the production zones. The total drilled depth for the three wells is 3760 m (12,041 ft). The top of the reservoir has been encountered at depths of between 492-869 m (1614-2850 ft) with the deepest production zone apparently close to the center of the field. The geothermal fluid produced is a mixture of hot water and steam, the chemical characteristics of which are not much different from those of the fluids at Ahuachapán, El Salvador. The fluid pH is 6.7; the total dissolved solids are about 5300 ppm consisting mainly of chloride, 2750 ppm, but with significant amounts of silica, 585 ppm, and arsenic, 5 ppm. Noncondensable gases in the steam fraction are less than 1% (by weight) with 97% (by volume) made up of CO_2, 0.5% (by volume) H_2S, with the rest being N_2, Ar, and hydrocarbons.

Presently the Instituto Costarricense de Electricidad (I.C.E.) is investigating various options for energy conversion systems. Serious consideration is being given to a double-flash (i.e., separated steam/hot water flash) plant of 55 MW (gross) generating capacity. Owing to the large number of wells that would be required for full, rated operation of such a plant, and other matters of concern, I.C.E. is also considering a less ambitious venture that would bring a plant of lower capacity on line sooner with less risk. I.C.E. hopes to have a plant operating at Miravalles by about 1985. They are currently arranging the financing for the next phase which will include drilling of additional wells and the design of the plant and gathering system.

El Salvador Owing to the unstable political state of affairs in El Salvador, very little recent information has come to light about the geothermal operations there beyond what was written in the previous Proceedings of this conference (5). The 3-unit plant at Ahuachapán continues to function as a vital component in the grid of El Salvador. The present capacity is 95 MW, the design value for the field. Although we have no data on the actual operation of the dual-pressure unit (No. 3) whose technical specifications were given in Ref. (5), we can report some statistics on the plant operations (units No. 1 and 2) from start-up in June 1975 through February 1980 (6). Table 2 shows the annual electricity generation at Ahuachapán since the plant was commissioned. As can be seen, the plant has been highly reliable and contributes nearly 30% of the total electricity requirements of El Salvador. Table 3 gives a monthly breakdown for 1979 and the first two months of 1980.

Table 2 Electricity generation at Ahuachapán

Year	MW·h gross	MW·h net	Capacity factor, %	% Total generation
1975	72,331	66,969	47	11.8
1976	279,800	260,062	67	25.4
1977	400,051	275,126	76	32.3
1978	391,025	365,645	74	28.4
1979	392,183	369,528	75	26.5
1980*	75,664	71,106	88	29.4

*January and February only.

The impact of an outage, e.g., the scheduled maintenance for one of the two 30 MW units during July and August of 1979 is easily gauged by examining the consumption of additional fossil fuels needed at the thermal plants to fill the gap. Most of El Salvador's conventional electricity comes from three hydroelectric stations, Cerron Grande, Guajoyo and 5th of November, with two fossil-fueled plants, Acajutla and Soyapango, producing power as needed. For 1979, during the ten months when Ahuachapán was at full capacity, the two fossil plants burned an average of 10,890 gal/mo of Bunker C oil and 13,690 gal/mo of diesel fuel. During the two months while Ahuachapán was at essentially half-capacity, the fossil plants burned, on average, 169,050 gal/mo of Bunker C oil and 112,900 gal/mo of diesel fuel. The Bunker C and diesel fuels cost roughly $12.50/bbl and $23.00/bbl, respectively, during the year. The annual savings in foreign exchange that could be attributed to each of the 30 MW units at Ahuachapán thus came to about $1,220,000 in 1979, a significant sum for El Salvador. Present fuel costs are about three times higher than those paid in 1979. Finally it should be noted that planned maintenance at Ahuachapán is always scheduled for the rainy season when sufficient hydroelectric capacity is available to help meet the demand.

Table 3 Electricity generation since January 1979 at Ahuachapán

Month	MW·h gross	MW·h net	Capacity[(1)] factor, %	% Total generation
JAN-79	37,671	35,374	84.4	29.2
FEB	35,559	33,561	88.2	30.1
MAR	39,585	37,288	88.7	31.1
APR	38,955	36,727	90.2	33.2
MAY	38,525	36,294	86.3	30.0
JUN	36,753	34,529	85.1	29.8
JUL[(2)]	22,830	21,463	51.1	18.2
AUG[(2)]	19,500	18,434	43.7	16.2
SEP	22,504	21,227	52.1	19.6
OCT	25,499	24,157	57.1	20.6
NOV	35,422	33,399	82.0	28.6
DEC	39,380	37,077	88.2	30.9
JAN-80	40,150	37,671	89.9	30.5
FEB	35,514	33,435	85.0	28.2

(1) On a monthly basis;

(2) Scheduled maintenance.

An outstanding geothermal prospect, extending over an area perhaps as large as 100 km^2 (24,700 acres), has been defined at Berlín in the east-central part of El Salvador. The first deep well in the present stage of development was completed during 1979 to a depth of 1902 m (6240 ft). The reservoir was encountered at a depth of 1799 m (5903 ft); reservoir temperature is about 310°C (590°F). The well, designated Tronador-2 (See Figs. 2 and 3), produces about 100 kg/s (793,000 lbm/h) of hot water and steam having a dryness fraction of about 0.40 (7). Based on preliminary assessments, it is believed that at least 110 MW can be produced at Berlín for 30 years. The first phase of power plant construction will lead to a 55 MW, double-flash plant in the 1985 time frame. The plant is projected to cost $46.3 M (or $842/kW) which includes $16 M for the energy conversion system and $14 M for the wells.

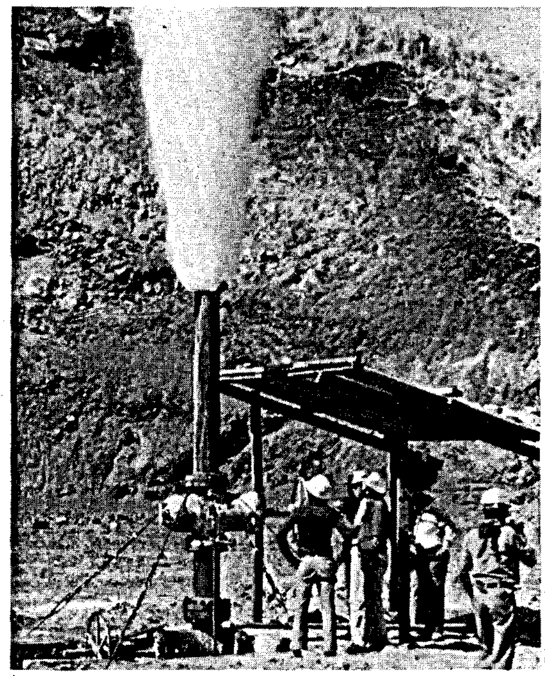

Fig. 2 Well Tronador-2 at Berlín, El Salvador. (Photo from C.E.L., El Salvador.)

Another good prospect has been discovered at San Vicente about 40 km (25 mi) north-northwest of Berlín. The first deep well encountered a highly permeable reservoir at 1000 m (3280 ft) with a temperature in excess of 200°C (392°F). Development of this field will continue with the hope of eventually building yet another geothermal plant.

El Salvador continues to lead the Latin American countries in the exploitation of geothermal energy as a means of meeting the energy demands of these countries that have traditionally relied mainly on hydroelectric stations with fossil-fueled plants as reservoirs. The sky-rocketting of fossil fuel prices has made the old strategy uneconomical and hence the turn to geothermal resources which, fortunately, the Latin American countries have in reasonable abundance.

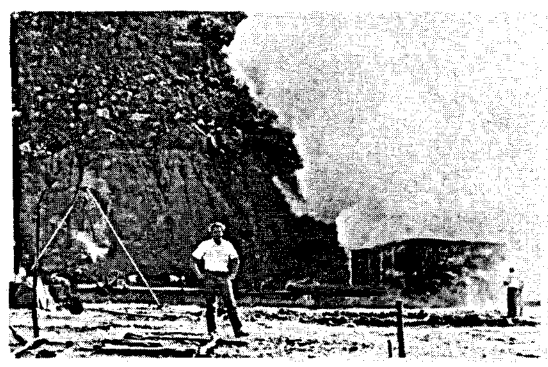

Fig. 3 Flow testing at Well Tr-2, Berlín. (Photo courtesy of R. Caceres, C.E.L., El Salvador.)

Indonesia Of the many areas throughout the Indonesian archipelago that exhibit surface manifestations of geothermal activity (8), only two are currently being exploited for electric power: Kawah Kamojang and Dieng, both on the island of Java. Wellhead units of the "Monoblok" design from Geothermal Power Co. of New York are installed at these sites: 250 kW (1978) at Kamojang and 2000 kW (1980) at Dieng.

A larger plant is under construction at Kamojang and is expected to come on-line late in 1981. It is a single-flash (i.e., separated steam) plant of 30 MW capacity. Technical particulars may be found in Table 4 (2). The specific steam consumption is 7.9 kg/kW·h (17.3 lbm/kW·h).

Table 4 Technical specifications for 30 MW unit at Kawah Kamojang (2)

Turbine data:

Type	Single cylinder, double flow, 5 x 2 stage impulse
Rated capacity	30,000 kW
Maximum capacity	31,500 kW
Speed	3,000 rev/min
Steam pressure	661 kPa ($95.9\ lbf/in^2$)
Steam temperature	161.9^oC (323.4^oF)
Exhaust pressure	13.3 kPa (3.9 in Hg)
Steam flow rate	235.8 t/h (519,700 lbm/h)
Noncondensable gases	1.0% (by weight of steam)
Last stage blade height	420 mm (16.5 in)
Maximum pressure	1069 kPa ($155\ lbf/in^2$)

Condenser data:

Type	Spray-tray, jet type
Pressure	13.3 kPa (3.9 in Hg)
Cooling water temperature	29^oC (84.2^oF)
Outlet water temperature	49.6^oC (121.3^oF)
Water flow rate	5690 t/h (12.54×10^6 lbm/h)

Gas extractor data:

Type	Two-stage, steam-jet
Capacity	$18,330\ m^3/h$ ($10,790\ ft^3/min$)
Steam consumption	8.27 t/h (18,227 lbm/h)

Kenya A 15 MW single-flash plant is scheduled to start generating electricity during 1981 at the Olkaria geothermal field in Kenya's Rift Valley Province. The reservoir is a high-temperature, liquid-dominated one characterized by relatively low permeability. The best wells produce about 8.3-11.1 kg/s (66-88,000 lbm/h) of hot water and steam; reservoir temperature is in the 250^oC (482^oF) range. Technical details on the first-phase, 15 MW plant are listed in Table 5 (2).

Table 5 Technical specifications for Olkaria unit No. 1 (2)

Turbine data:

Type	Single cylinder, single flow, 4-stage impulse
Rated capacity	15,000 kW
Maximum capacity	15,000 kW
Speed	3,000 rev/min
Steam pressure	487.4 kPa ($70.7\ lbf/in^2$)
Steam temperature	151.9^oC (305.4^oF)
Exhaust pressure	12.7 kPa (3.75 in Hg)
Steam flow rate	134.1 t/h (295,556 lbm/h)
Noncondensable gases	0.5% (by weight of steam)
Last stage blade height	420 mm (16.5 in)
Maximum pressure	981 kPa ($142\ lbf/in^2$

Condenser data:

Type	Barometric, spray-jet type
Cooling water temperature	20^oC (68^oF)
Outlet water temperature	48.7^oC (119.7^oF)
Water flow rate	2,328 t/h (5.13×10^6 lbm/h)

Gas extractor data:

Type	Two-stage, steam ejector
Number of sets	Three (50% capacity each)
Capacity, per set	$2,140\ m^3/h$ ($1,260\ ft^3/min$)
Steam consumption, per set	1.48 t/h (3,262 lbm/h)

(Table continued on next page)

Cooling tower data:

Type......................	Cross-flow, mechanical, induced draft
Number of cells...........	Three
Water flow rate...........	2,590 t/h (5.71×10^6 lbm/h)
Design wet-bulb temperature...........	14^oC (57.2^oF)

An order has already been placed for a duplicate second unit. Two drilling rigs are at the site. The project is being supported financially by the World Bank and the United Nations as part of the U.N. effort to encourage development of alternative energy resources in Lesser Developed Countries (9). The second unit should be on-stream in 1982 according to plans of the Kenya Power Company, Ltd. of Nairobi. The power plant will cost about $10.34 M or $690/kW, excluding the cost of the wells and the gathering system (10).

Turkey The Mineral Research and Exploration Institute (M.T.A.) of Turkey has for some years been operating a 500 kW experimental geothermal unit at Kızıldere. Since 1975 the plant has been run at various power levels as part of an on-going development project. Figures 4 and 5 show an overall view of the plant and a view of the turbo-generator, respectively. Table 6 lists the technical details for the unit (Personal communication, O. Mertoğlu). The well, KD-XII, produces a total, two-phase flow of 38.2 kg/s (303,000 lbm/h) with a dryness fraction of 0.0947.

A new 5 MW plant is being built at the workshop of the M.T.A. and is scheduled to go on stream at Kızıldere during 1982. At this time, the wellhead equipment, i.e., cyclone separator, silencer, ball check valve, and associated piping, has been fabricated; the turbine is under construction.

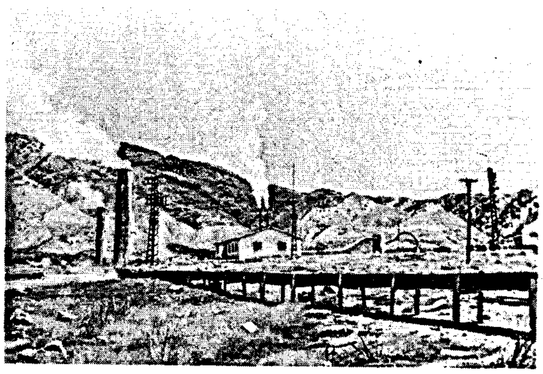

Fig. 4 Wellhead power plant at Kızıldere, Turkey.
(Photo courtesy of O. Mertoğlu, M.T.A., Turkey.)

Table 6 Technical specifications for Kızıldere wellhead unit

Turbine type..............	Single cylinder, single impulse (Curtis) stage, back-pressure, geared
Rated capacity............	500 kW
Speed (turbine/generator).	4,500/1,500 rev/min
Steam pressure............	486 kPa (70.5 lbf/in^2)
Steam temperature.........	150^oC (302^oF)
Exhaust pressure..........	115 kPa (16.7 lbf/in^2)
Steam flow rate...........	13.0 t/h (28,697 lbm/h)
Noncondensable gases......	17% (by weight of steam)
Last stage blade height...	76 mm (3 in)
Maximum pressure..........	786 kPa (114 lbf/in^2)

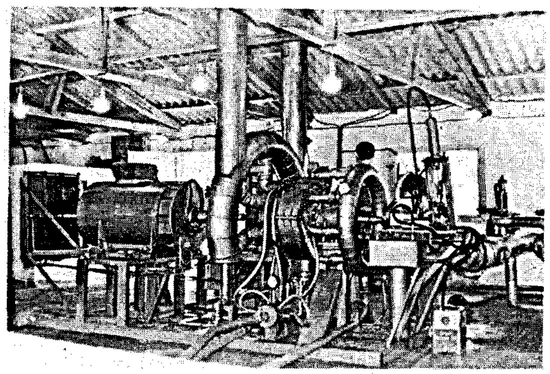

Fig. 5 Turbine-generator of wellhead unit at Kızıldere.
(Photo courtesy of O. Mertoğlu, M.T.A., Turkey.)

Union of Soviet Socialist Republics. A 5 MW flash-steam plant has been in operation at Pauzhetka on the Kamchatka Peninsula since 1967 (8). It has been reported recently in Pravda (Jan. 22, 1981), and cited in Ref. (11), that the plant has been expanded in its capacity to 11 MW. The ultimate potential of the field may be as high as 50-70 MW, but the proven steam reserves seem capable of supplying about 17 MW. Waste fluid from the plant is disposed of by means of discharge to surface waters without reinjection. The geofluid is relatively clean, having a total of about 3500 ppm dissolved solids (8).

A 10 MW single-flash plant will be constructed at the Neftekumsk area of Stavropol' Kray. The area is one of two marked by geothermal anomalies in the Soviet Union. Temperature gradients of 40-45°C/km (22-25°F/1000 ft) have been recorded. Reservoir temperatures of 170-190°C (338-374°F) exist at depths of 4000-5000 m (13,125-16,400 ft). The waste liquid from the plant will be reinjected into the formation (12).

It has been speculated that the Soviets are considering building rather large geothermal plants next to volcanos: 200 MW near Mutnovskaya Volcano, and one near Koshelev Volcano (near Pauzhetka) (11), and even a 5000 MW geothermal power complex near Avachinski Volcano (8), all on the Kamchatka Peninsula. Such projects would seem to require monumental efforts to win sufficient steam, or a quantum jump in the state of the art of geothermal power technology along the lines of direct magma tapping.

Acknowledgments The following people have provided me with valuable information in the course of putting together the material on which this paper is based: Ing. R. Caceres, Mr. O. Mertoğlu, Mr. T. Shabad, Mr. Bill Tanaka, Dr. Zhi-jian Wu.

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GEOTHERMAL ELECTRICITY GENERATING STATIONS:

WORLDWIDE SUMMARY AS OF JUNE 1981

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In the one year since a similar survey was taken [1], there has been a growth of about 16 percent in the installed electricity generating capacity from geothermal power stations around the world. Had it not been for the rapid growth in the Philippines, the rate of increase would be even more modest. The Philippines has doubled its geothermal capacity, going from 224 MW to 446 MW in one year. The United States remains the leading country with about 37 percent of the total worldwide geothermal capacity. Viable programs exist in Italy, New Zealand, Mexico, Japan, and El Salvador, in spite of the zero growth in these countries since last year. New plants are under construction in Mexico and Japan, and field development is proceeding at a new site in El Salvador. The number of other countries getting started in geothermal electricity generation continues to grow, as can be seen in the accompanying table. Some of these countries are the subject of a companion paper in these Proceedings by the author.

[1] DiPippo, R., "Worldwide Geothermal Power Plants: Status as of June 1980", Proc. Fourth Annual Geothermal Conference and Workshop, EPRI TC-80-907, December 1980, pp. 7.63 - 7.67.

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SUMMARY OF INSTALLED GEOTHERMAL ELECTRICITY GENERATING CAPACITY - JUNE 1981

Rank	Country	No. Units	Capacity, MW	Percent of Total
1	United States	18	932.2	37.4
2	Philippines	10	446.0	17.9
3	Italy	38	439.6	17.6
4	New Zealand	14	202.6	8.1
5	Japan	7	168.0	6.7
6	Mexico	4	150.0	6.0
7	El Salvador	3	95.0	3.8
8	Iceland	5	41.0	1.6
9	Soviet Union	1	11.0	0.44
10	Azores (Portugal)	1	3.0	0.12
11	Indonesia	2	2.25	0.09
12	China	7	1.936	0.08
13	Turkey	1	0.5	0.02
	TOTALS:	111 units	2493.086 MW	100. %

WHAT NEXT IN GEOTHERMAL POWER DEVELOPMENT?

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INTRODUCTION Forecasting the future of geothermal power development is a speculative but necessary activity for both government and the private sector. A forecast may be based upon a simple extrapolation of historical data (time-series analysis) or it may be based upon a sensitivity analysis of postulated cause-and-effect mechanisms subject to external control (regression analysis). This paper will attempt to examine the importance of some of these discretionary variables on the future of geothermal development.

Before making any projections, an historical perspective is in order. Figure 1 shows that previous forecasts for electric power development by the year 2000 have declined. This trend primarily reflects more realism in the assessment of developing an alternative energy source by the electric utility industry in a period of reduced demand growth rather than a decrease in the resource potential itself. The total electric power resource potential above 150 C estimated in 1976 was 153,000 MWe as opposed to the most recent estimate of 95,000 - 150,000 MWe. The projected level of development by the year 2000 is thus clearly not constrained by resource potential.

THE PERCEPTION OF RISK If development is not presently resource-constrained, then what factors are impeding development? The comments which follow primarily concern liquid-dominated resources. The Geysers dry-steam field is following an orderly and predictable course of development which is essentially independent from that of liquid-dominated resources. This is because The Geysers resource has been calibrated to the extent that acceptable bounds on risk exist. The technology problems and their solutions are known, power plant reliability is understood, institutional problems are in clear perspective, and the economics are favorable. Once this stage of development is realized in the liquid hydrothermal industry, the full potential of the resource will be developed.

Risk, whether technical or otherwise, always translates into an economic factor. If the risk adjusted rate of return for geothermal power is not competitive with alternate opportunities for investment, then development will flounder.

In order to assess risks and to what extent and how they must be quantified, an examination of the development process is required. The process comprises the major phases of geophysical survey, land acquisition, exploratory drilling and reservoir characterization, production well drilling, and plant construction. The typical timing of these development activities is shown in Figure 2. Table 1 shows the status of geothermal leasing on public lands through 1980. The highest bid in 1980 was submitted by Chevron USA for 10.26 acres in the Heber KGRA at $4,403 an acre, or $45,776 for the parcel. The largest leased parcel was in Oregon's Alvord KGRA, for which Getty Oil bid $20.99 per acre for 14,461 acres. Apparently, the perceived risks are not presently a deterrent to the first two phases of geothermal development.

Once lease rights are acquired, exploration and field development may occur. Table 2 gives the number of deep geothermal wells drilled by location during the period 1978-80 and the total footage drilled during the period between 1973 and 1980. Approximately 3 million feet of hole have been drilled, half of which is on liquid hydrothermal resource prospects. At today's well costs of $130/ft., this represents an investment approaching $400 million. Again, one could conclude that the perceived risk at this stage of development is not the primary present deterrent.

The next phase of development beyond exploration and discovery involves fluid production, utilization for electric power production, and disposal. To date, four power plants have been constructed on liquid-dominated resources and two have actually been operated. The federally funded Raft River 5 MWe binary plant and the federally cost-shared 3 MWe flash-steam plant in Hawaii are essentially complete but have not been operated. Magma's 11 MWe East Mesa binary plant and SCE's 10 MWe Brawley flash-steam plant have both shown the operating potential of these resources. The 21 MWe installed capacity at East Mesa and Brawley is 1/3 of one percent of the estimated 6,000 MWe potential of Imperial Valley alone.

Figure 3 shows competitive KGRA land leasing activity on federal lands since 1974 and Figure 4 shows the trend of geothermal well completions as compared to utility commitments to power plants at liquid-dominated sites. Three important observations can be made from this information:

- Utility commitments are lagging about 12 years behind the pace of leasing.
- The pace of leasing has tapered off due to the lack of interest on the part of utilities.
- Although there is presently a significant gap between power plant commitments and the available potential of completed wells, the situation should improve over the next few years to where the wells are more fully utilized.

Clearly, the rate of power plant development and operation does not reflect the same level of activity as exists elsewhere in the geothermal development process. What are the constraining factors and how may they be altered? Although electric power demand growth is down considerably nationwide, geothermal resources are predominantly co-located with areas of continuing demand growth and development is not constrained by lack of demand.

Pure economic factors, i.e., those not associated with technological considerations, are contributing to the constraints. Utilities have encountered increasing difficulties in long-term debt financing and are being constantly squeezed by increasing costs on one hand and regulatory pressure to minimize rate increases on the other. This financial climate accentuates the inherent conservatism of the utility industry, placing a premium on minimizing risk. Figure 5 outlines the spectrum of risks which the power industry must assess in evaluating geothermal power development. Obviously, the best means of quantifying these elements of risk is through experience. Since domestic liquid-dominated development experience is lacking, one must resort to a review of international experience as well as domestic dry-steam development history.

GEOTHERMAL EXPERIENCE AND ECONOMIC VIABILITY

Approximately 2,000 MWe of geothermal electric capacity is presently operational world wide, of which 75% utilizes dry-steam resources. International experience has been highly favorable, from both technical and economic viewpoints. Plant capacity factors have typically exceeded 80% and power costs have consistently been among the lowest of the generating mix of the systems involved. There have been only two instances of documented failure to produce rated capacity once commitment to hardware was made. The Onikobe plant in Japan produces only half of its rated 25 MWe capacity and approximately 8 MWe is being produced by a 30 MWe unit in Krafla, Iceland, with an additional 30 MWe turbine generator purchased but uninstalled. In both cases, limited fluid production has been responsible for failure to meet rated output.

The state of the art in geothermal reservoir engineering is admittedly in its infancy. However, multi-well flow testing for periods of several months or more (depending upon permeability and reservoir volume) provides a reliable basis for at least a conservative estimate of reservoir capacity and longevity. As production increases in terms of flow volume and duration, reliability increases and risk declines. Reservoir recharge is hypothesized to occur in many instances. The Wairakei geothermal field in New Zealand, which has been in full production longer than any other liquid-dominated field, has an estimated recharge of over 80% based on gravity surveys (Hunt, T.M., N.Z.J. Geol. Geophys., Vol. 2).

The historical trends in geothermal power plant sizes are shown in Figures 6, 7 and 8. Figure 6 shows the fraction of total worldwide installed capacity attributable to different plant sizes and indicates the total installed capacity. Figure 7 shows the same information for the U.S. Figure 8 illustrates the trends in the largest and average geothermal plant sizes in the U.S. and worldwide from 1920 to 1980. These trends reflect the graduated step-out philosophy in assessing resource viability.

The economics of geothermal energy, like all natural resources, are strongly site-dependent. Such factors as reservoir temperature, permeability, depth, rock type, salinity, and geochemistry can all strongly influence power costs. Comparisons among different technologies are complicated by not only resource-related assumptions, but also costing methodology assumptions. Table 3 illustrates typical comparisons according to different economic "conventions." The influence of site-specific variables is readily apparent in the comparison between the Heber and Baca sites. The reasons for high costs on the proposed SDG&E binary plant (Heber) are straightforward. At 365°F, the binary plant requires approximately 2 1/2 times the brine flow rate as the 550°F flash plant (Baca). This higher brine flow dictates larger piping, valves, and injection pumps. The lower temperature necessarily means a 20% lower thermal efficiency, which requires approximately 20% larger condensers, cooling towers, water circulating pumps, and 20% more make-up water. In addition, the lower vapor pressure of the 365°F brine causes wells to be low in productivity unless they are pumped. The binary plant will use approximately 5MWe of parasitic power for downhole pumps, which is not required for the 550°F resource, plus an additional 2MWe of parasitic power for injection pumps. Downhole pumps will add $2.5 million to initial capital costs and will require frequent maintenance and replacement.

Table 4, taken from a paper entitled "Economic Review of Advanced Fuel and Power Technologies" prepared internally by Bechtel, compares different power technology generation costs using slightly optimistic but even-handed assumptions about each alternative. The table shows that the cost of geothermal power is competitive and should not pose a detriment to development.

The conclusion of this section is that the risks associated with near-term geothermal development are more perceived than real. Nevertheless, they pose an important obstacle. Longer-term geothermal development requires the ability to exploit the less economic resources (especially the lower-temperature resources) and technological innovation will clearly be a prerequisite to significant development.

THE ROLE OF TECHNOLOGY IN FUTURE DEVELOPMENT The history of technological success in dealing with geothermal problems has been impressive. The once unmanageable Salton Sea high-salinity resource can now be economically produced and utilized. New materials, instrumentation, drill bits, cements, and other innovations have greatly increased component reliability and life. Although substantial improvements have been realized, it is clear that continued technological innovation will be required if the bulk of the resource base is to be developed. Figure 9 (from USGS Circular 790) illustrates the resource-temperature distribution. It is clear from this figure that the majority of the resource base exists at temperatures below 200°C, where present technology is at best marginally economic. The economic degradation with declining reservoir temperature is primarily attributable to the dramatic increase in geothermal flow rates required per kWe as temperature declines. As previously mentioned, a 365°F resource requires 2½ times more fluid supply than a 550°F resource to produce equivalent power. Since well productivity also typically declines with temperature, the economic impact on field development (number of wells) and fluid handling costs is dramatic. The prospects for technological advances to compensate for these thermodynamic penalties are fortunately high. Under DOE sponsorship, the development of improved drill bits, lost circulation control methods, reservoir stimulation, downhole pumping equipment, and more efficient binary technology is well underway. Even moderate success in these programs can result in significant reductions in moderate-temperature power costs.

A PRAGMATIC COURSE, FIRST-GENERATION POWER PLANTS So far, the pattern for growth of the average geothermal plant size (see Figure 8) has been similar to the pattern followed by the size of steam power plants, which is shown for the U.S. in Figure 10. It is anticipated that larger and more economical geothermal plants will be designed and built in the future.

A trend has appeared in the early stage of liquid-dominated hydrothermal resource development which parallels development at The Geysers as well as previous international development. This is the 10-20 MWe "ice-breaker" plant concept. The operation of efficient and integrated small plants will enable developers and utility companies to generate revenues while reservoirs and utilization technologies are being tested prior to the construction of larger power plants. Table 5 lists the announced plans for new geothermal power plants outside The Geysers through 1990. The use of small plants to quantify the risks associated primarily with the reservoir and fluid production and disposal, as well as the power plant, is clearly an integral part of the development strategy. As was shown in Figure 4, power plant commitments have already begun to more closely match the successful completion of wells, in terms of MWe.

The similarities between geothermal and conventional power development and the current plans for geothermal plants indicate convincingly that the continued expansion of geothermal power generating capabilities will rely heavily on small first-generation plants. This approach, supplemented by continuous technological advances, should make credible a 10,000 - 20,000 MWe forecast for the year 2000.

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1. Booz Allen & Hamilton Inc. (1980), "Geothermal Industry Assessment", NTIS no. DOE/PE/70090-T2.

2. U.S. Department of Energy (1980), "Geothermal Progress Monitor", Reports 4 and 5, NTIS no. DOE/CE-0009/5.

3. U.S. Geological Survey(1978), "Assessment of Geothermal Resources in the United States-1978", Circular 790.

4. U.S. Geological Survey, Conservation Division, Office of Deputy Conservation Manager for Geothermal, Menlo Park, CA.

5. Federal Power Commission (1971), "The National Power Survey, Part 1", U.S. Government Printing Office.

FIGURE 1

COMPARISON OF RECENT GEOTHERMAL ELECTRIC ENERGY UTILIZATION PROJECTIONS FOR THE YEAR 2000

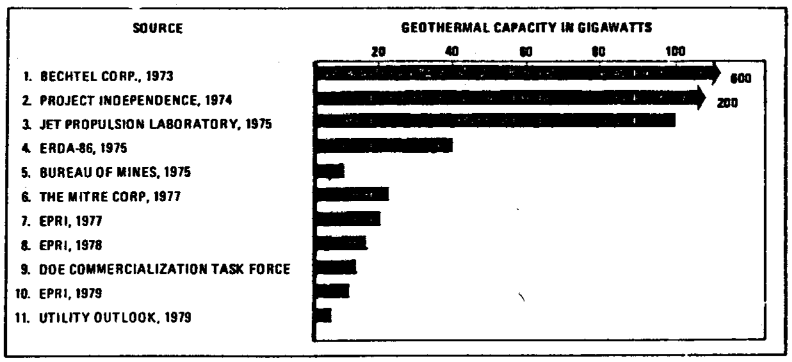
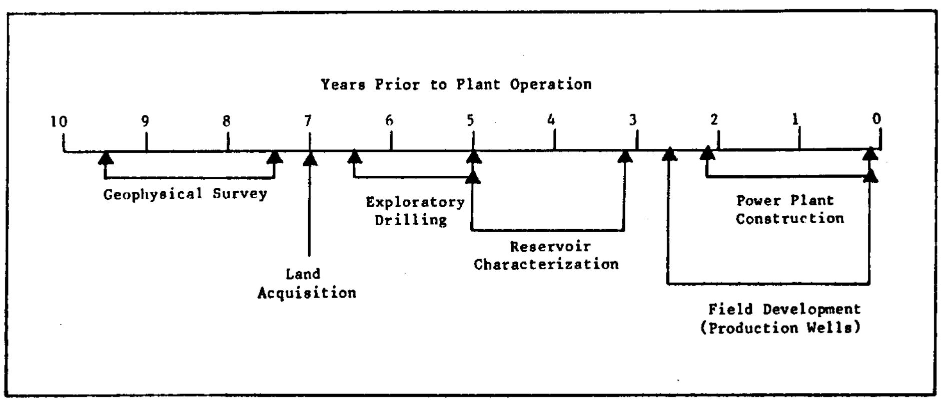


FIGURE 2

TYPICAL HYDROTHERMAL POWER DEVELOPMENT SEQUENCE



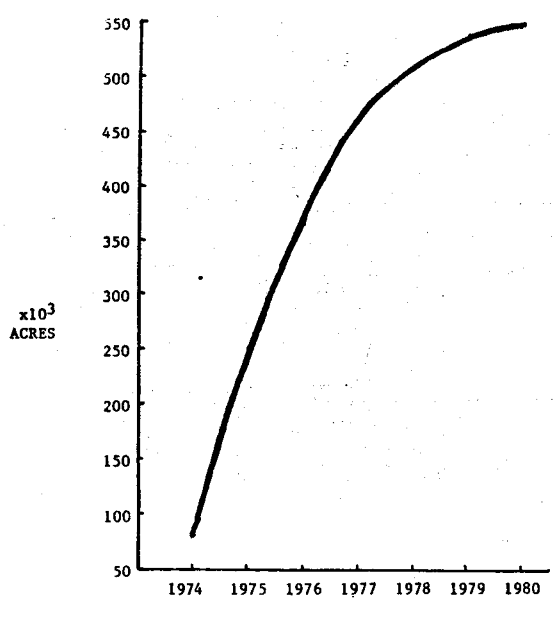


FIGURE 3

COMPETITIVE LEASING OF FEDERAL KGRA LANDS

FIGURE 4

UTILITY LIQUID-DOMINATED HYDROTHERMAL POWER PLANT COMMITMENTS AND SUCCESSFUL WELL COMPLETIONS VERSUS TIME

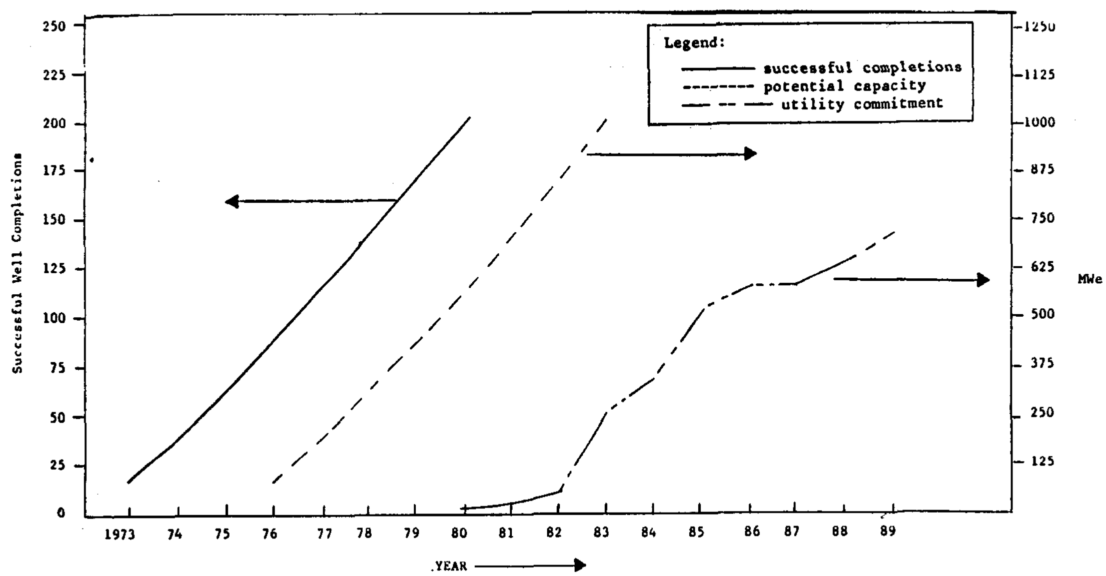
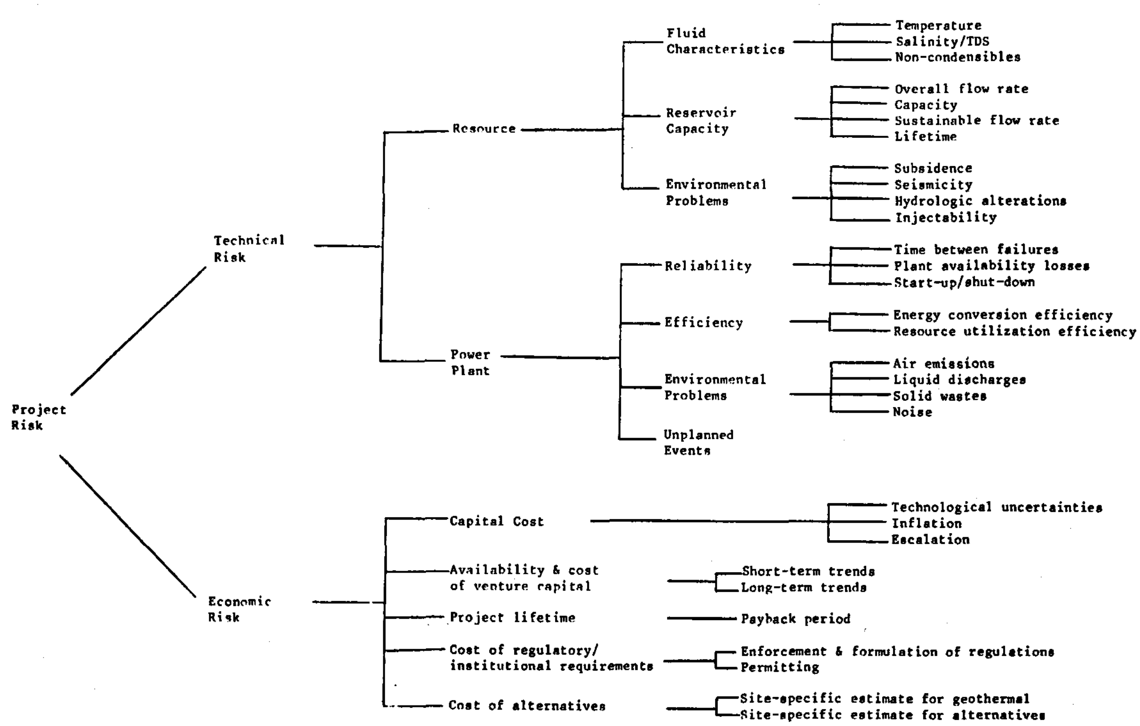


FIGURE 5

SOURCES OF RISK ASSOCIATED WITH GEOTHERMAL POWER SYSTEMS



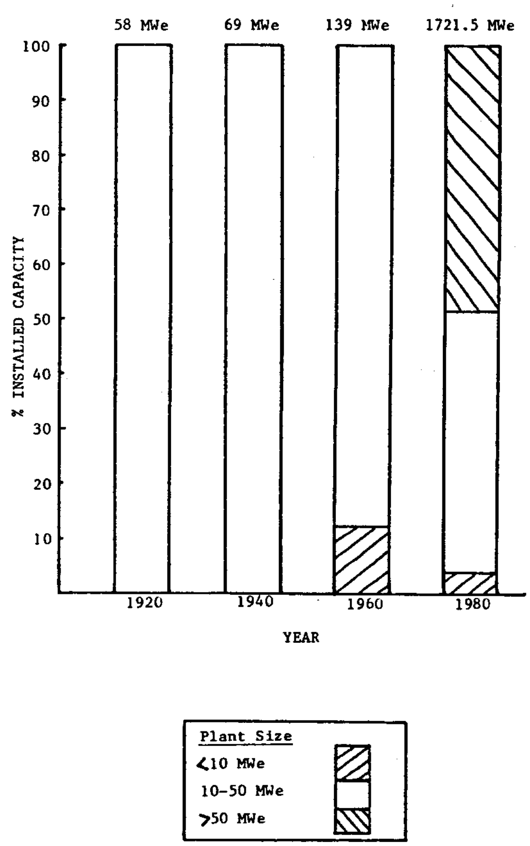
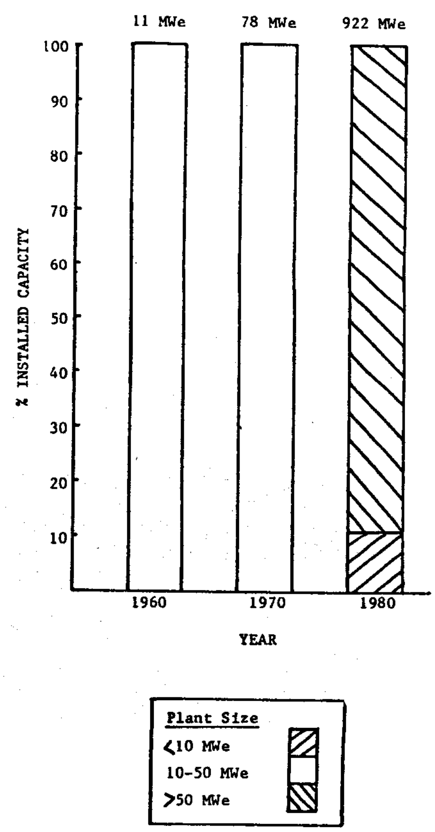


FIGURE 6

PROPORTION OF WORLD-WIDE GEOTHERMAL POWER GENERATED BY DIFFERENT PLANT SIZES

FIGURE 7

PROPORTION OF U.S. GEOTHERMAL POWER GENERATED BY DIFFERENT PLANT SIZES



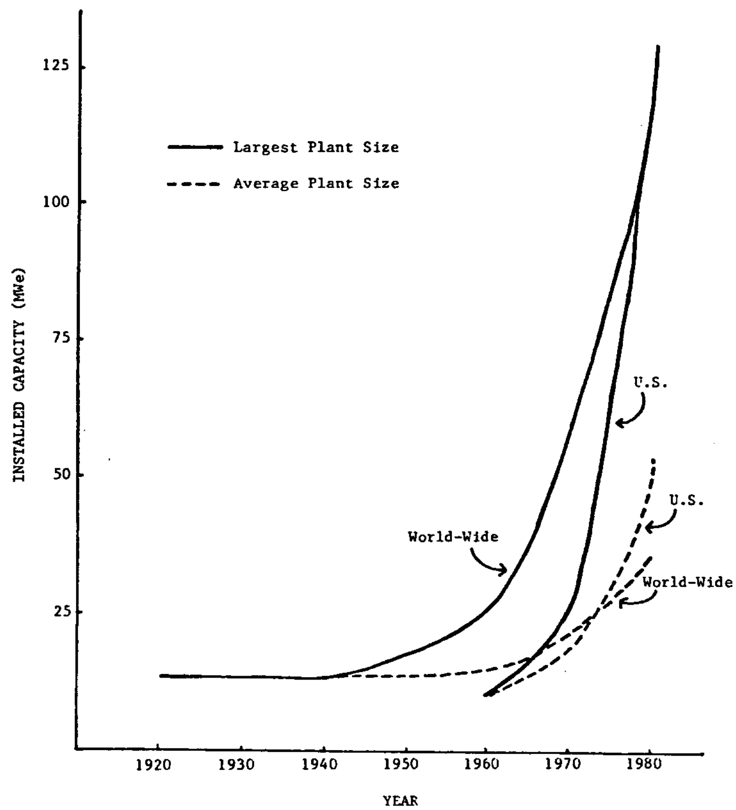


FIGURE 8

TRENDS IN LARGEST AND AVERAGE PLANT SIZES FOR WORLD AND U.S.

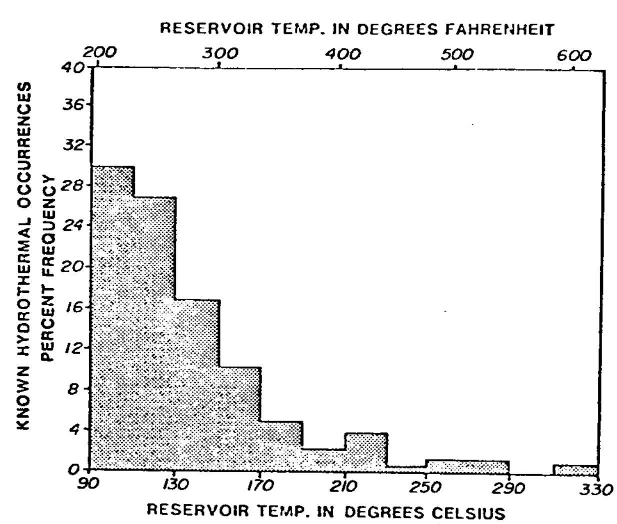
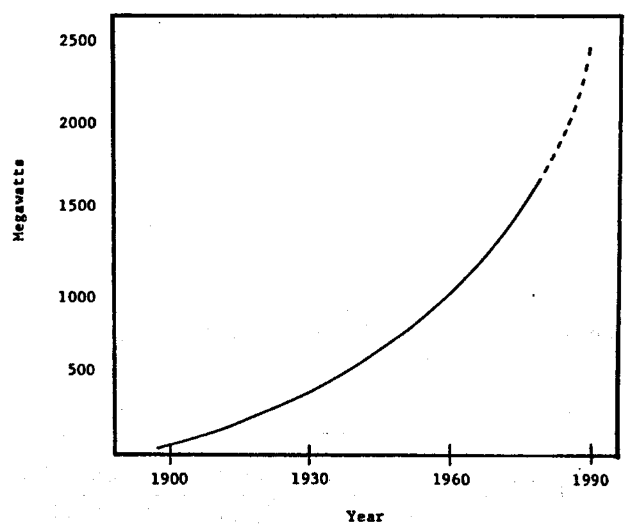


FIGURE 9

PERCENT FREQUENCY OF IDENTIFIED U.S. HYDROTHERMAL RESOURCES BY TEMPERATURE

FIGURE 10

GROWTH TREND FOR LARGEST STEAM ELECTRIC
TURBINE GENERATORS IN SERVICE (U.S.)



STATE	NUMBER OF LEASES[1]			ACREAGE LEASED[1]		
	1979	1980	CHANGE	1979	1980	CHANGE
Alaska	-0-	-0-	-0-	-0-	-0-	-0-
Arizona	13	13	-0-	21,541	21,541	-0-
California[2]	57	56	-1	68,943	67,830	-1,113
Colorado	25	22	-3	34,927	30,476	-4,451
Idaho	136	86	-50	246,722	153,427	-93,295
Montana	6	-0-	-6	10,687	-0-	-10,687
Nevada[3]	499	647	+148	954,577	1,201,257	+246,680
New Mexico	121	120	-1	220,155	210,014	-10,141
Oregon	150	233	+83	228,929	375,740	+146,811
Utah	278	269	-9	472,507	453,677	-18,830
Virginia	11	11	-0-	19,774	19,774	-0-
Washington	-0-	2	+2	-0-	5,120	+5,120
Wyoming	4	4	-0-	7,448	7,448	-0-
TOTAL	1,300	1,463	+163	2,286,210	2,546,304	+260,094

[1]As of September 30 in the respective years

[2]Includes one lease of 120 acres on Indian land.

[3]Includes one prospecting permit on 79,590 acres on Indian land.

TABLE 1

CHANGES IN THE STATUS OF GEOTHERMAL LEASING ON PUBLIC LAND DURING FY 1980

Source: Reference

TABLE 2

NUMBER OF DEEP WELLS COMPLETED AND TOTAL FOOTAGE DRILLED 1973-80

YEAR / STATE	1978		1979		1980		1973-80 TOTAL	
	NO.	FOOTAGE	NO.	FOOTAGE	NO.	FOOTAGE	NO.	FOOTAGE
ARIZONA	-	-	5	21235	-	-	8	48923
CALIFORNIA								
Geysers	24	190183	30	208961	40	292638	212	1574052
Imp. Valley	12	92227	10	64844	7	60424	77	524526
Other	3	17035	3	13543	1	9104	16	97066
HAWAII	1	5595	1	6500	1	7000	5	29668
IDAHO	7	38385	2	14356	1	7981	16	106569
LOUISIANA	1	16234	1	15231	2	32942	4	64407
MARYLAND	-	-	1	5562	-	-	1	5562
MONTANA	-	-	-	-	-	-	1	6790
NEW MEXICO	1	6254	2	13010	4	23380	16	111495
NEVADA	4	21503	12	72523	8	57399	40	229211
OREGON	1	4003	2	12874	3	13004	10	51501
SOUTH DAKOTA	1	4266	1	4112	-	-	2	8378
TEXAS	1	2628	3	24320	1	13940	5	40888
UTAH	3	20742	2	17654	-	-	15	114176
TOTAL	59	419055	75	494725	68	517812	428	3013212

TABLE 3

ESTIMATED BUSBAR COST OF POWER AT BACA AND HEBER PLANTS (Mills/kWh)*

Start Up	Geothermal	Initial Year of Operation	Levelized Current Dollars	Levelized Constant Dollars
1982	PNM Baca Flash Demo . (50% DOE funded plant)	42	62	36
1982	Baca Subsequent unit (no DOE funds)	43	64	36
1985	SDG&E Heber Binary Demo (cost estimates ignore 50% DOE funding)	89	129	75

*in year of start-up dollars

assumptions:

PNM - 80% capacity factor
escalation 7% to 1982

SDG&E - 75% capacity factor
escalation 7% per year to 1985

TABLE 4

POWER TECHNOLOGIES COST SUMMARY
(Constant 1979 $)

Power Technology	Size	Year	Total Capital Investment $ Millions	Capital Investment $/kWe	Mills/kWh		Equivalent $/MMBtu	
					Break-even	5% ROI AFIT	Break-even	5% ROI AFIT
Nuclear — light water reactor**	1,200 MWe	1979	900	750	16	26	4.70	7.60
Conventional coal-fired plant with scrubbing	800 MWe	1979	475	595	19	27	5.60	7.80
Combined cycle								
No. 2 distillate fuel	800 MWe	1979	300	375	29	34	8.50	10.00
Integrated coal gasification	100 MWe	1985	145	1,450	34	52	10.00	15.20
Atmospheric fluidized bed combustion	600 MWe	1990	400	680	24	33	7.10	9.70
Pressurized fluidized bed combustion	400 MWe	1990	300	750	25	34	7.30	10.00
		2000	210	700	23	30	6.80	8.80
Geothermal	100 MWe							
Steam		1985	45	450	23	29	6.90	8.50
Brine		1985	75	750	31	39	9.20	11.40
Breeder reactor**	2-unit 3,000 MWe	1985	4,500	1,500	25	44	7.40	12.90
		1990	3,900	1,300	23	39	6.70	11.40
		2000	3,300	1,100	21	34	6.00	10.00
Magnetohydrodynamics	1,000 MWe	2000	1,250	1,250	27	42	7.80	12.30
Fuel cells	100 MWe	1990	100	1,000	46	58	13.60	17.00
		2000	75	750	43	52	12.60	15.20
Biomass — power	150 MWe	2000	165	1,100	46	58	13.50	17.10
Wind	2 MWe	1985	3.7	1,850	45	78	13.20	22.90
		1990	3.0	1,500	37	64	10.70	18.80
		2000	2.0	1,000	25	43	7.30	12.60
Ocean thermal energy conversion	100 MWe	1990	230	2,300	39	67	11.30	19.60
		2000	210	2,100	35	61	10.30	17.90
Solar photovoltaic	200 MWe	2000	180	900	35	62	10.30	18.20
Solar thermal	150 MWe	1990	398	2,650	49	95	14.30	27.80
		2000	300	2,000	38	73	11.20	21.40

*Basic premises used in the analyses are presented in Section V, Economic Criteria.
**Based on nuclear fuel valued at $0.62/MMBtu equivalent to U_3O_8 value of $40/lb.

TABLE 5

PROPOSED U.S. GEOTHERMAL POWER PLANTS OUTSIDE THE GEYSERS

STATE	AREA	DEVELOPER	UTILITY	PLANT	PLANT TYPE	NET OUTPUT MWE	YEAR ON LINE	PLANT COST $ 000
CA	Brawley	Union Oil	SCE					
CA	Brawley	CU-I Venture	CDWR		Flash	45	1984	
CA	Brawley	Union Oil	SCE	SCE				
CA	Coso	California Energy	US NAVY	COSO #1	Flash	20	1983	
CA	Coso	California Energy	US NAVY	COSO #2	Flash	55	1989	
CA	East Mesa	Republic Geothermal	SDG&E		Flash	50	1982	80,000
CA	Reber	Chevron	SDG&E		Binary	45	1985	128,400
CA	Reber	Chevron	SCE	SCE #1	Flash	50	1983	
CA	Reber	Chevron	SCE	SCE #2	Flash	100	1986	110,000
CA	Mono-Long Valley	Magma Power	SCE		Hybrid	20	1985	
CA	Niland	Union Oil	SCE	SCE				
CA	Niland	Union Oil	SCE	SCE PILOT		10	1982	
CA	Niland	Magma Power	SDG&E	SDG&E# 1	Flash	26	1983	30,000
CA	Niland	Magma Power	SDG&E	SDG&E# 2	Flash	49	1985	50,000
CA	Wendel-Amedee	Geoproducts	CDWR		Hybrid	50	1985	60,000
CA	Westmorland	Republic Geothermal			Flash	48	1984	
HI	Puna	Thermal-Dillingham	HELCO			25	1988	
HI	Puna	State of Hawaii	HELCO	HGP-A	Flash	3	1981	7,000
ID	Raft River	INEL/EG&G			Binary	5		24,000
NM	Valles Caldera	Union Oil	PNM	BACA #1	Flash	45	1983	
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#1	Binary	10	1982	
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#2	Binary	10		
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#3	Flash	10		
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #1	Flash	20	1983	20,000
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #2	Flash			
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #3				
STATUS TOTAL						2,237		670,574

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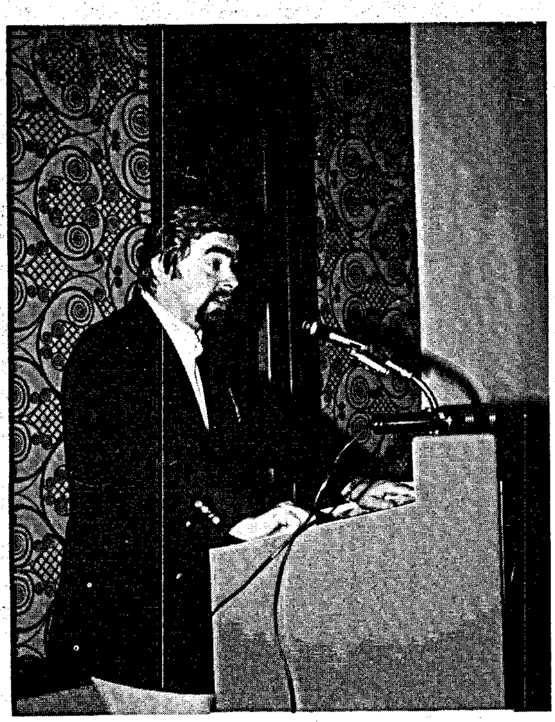
ERICKSON, MARY	WESTEC SERVICES	3211 FIFTH AVE.	SAN DIEGO, CA	92103	(714) 294-9770
FALCONE, D.J.	GEOTHERMAL RESOURCES INT'L	545 MIDDLEFIELD RD.	MENLO PARK, CA	94025	
FAHEY, EILEEN	SAN DIEGO GAS & ELECTRIC	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7733

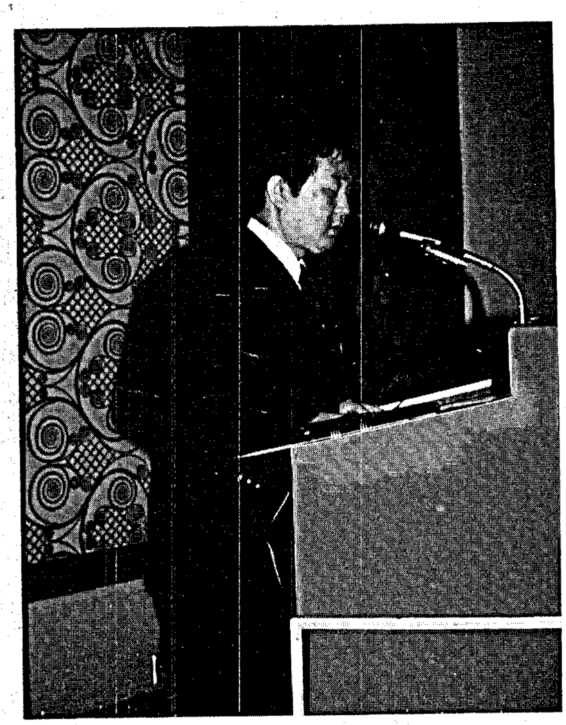
FUJIKAWA, T.	C/O MITSUBISHI INT'L CORP. ATTN: BILL TANAKA	50 CALIFORNIA ST, #3000	SAN FRANCISCO, CA	94111	(415) 981-1910
GADDY, JAMES	LOS ALAMOS NAT'L LAB	P.O. BOX 1663	LOS ALAMOS, NM	87545	(505) 667-4318
GARIBALDI, F.	COMISION FED. de ELECTRICIDAD	P.O. BOX 248	CALEXICO, CA	92231	(706) 562-8501
GILES, CLEM	THE BEN HOLT CO.	201 S. LAKE AVE.	PASADENA, CA	91101	(213) 684-2541
GONZALES, JOHN L.	U.S. DOE, GEOTHERMAL DIV.	1333 BROADWAY	OAKLAND, CA	94612	(415) 273-7943
GREIDER, B.	GEOTHERMAL RESOURCES INT'L	545 MIDDLEFIELD RD.	MENLO PARK, CA	94025	
GUDMUNDSSON, J.S.	NATIONAL ENERGY AUTHORITY	GRENSASVEGI 9	108 REYKJAVÍK, ICELAND		
GUY, JACK	ELECTRIC POWER RESEARCH INST.	1800 MASSACHUSETTS AVE, NW	WASHINGTON, DC	20036	(202) 872-9222
HANKIN, J.W.	BECHTEL GROUP, INC.	P.O. BOX 3965	SAN FRANCISCO, CA	94119	(415) 768-5760
HARBAN, D.C.	PHILLIPS GEOTHERMAL CO.	P.O. BOX 239	SALT LAKE CITY, UT	84110	(801) 364-2083
HAYS, LANCE	BIPHASE ENERGY SYSTEMS	2800 AIRPORT AVE.	SANTA MONICA, CA	90405	(213) 391-0691
HELLIER, BRUCE H.	U.S. GEOLOGICAL SURVEY	2465 EAST BAYSHORE RD.	PALO ALTO, CA	94303	(415) 323-8111
HIGUERA, RICHARD	LOS ANGELES DEPT OF WTR & PWR	P.O. BOX 111	LOS ANGELES, CA	90051	(213) 481-5019
HINRICHS, T.	MAGMA POWER CO.	P.O. BOX 2082	ESCONDIDO, CA	92025	(714) 743-7008
HIROSE, YASUMICHI	MINISTRY OF INT'L TRADE& IND.	1-3-1 KASUMIGASEKI CHIYODA-KU, TOKYO, JAPAN 100			3-501-1511
HOLM, JOHN	ROTOFLOW CORP.	2235 CARMELINA AVE.	LOS ANGELES, CA	90064	(213) 477-3083
HOLT, BEN	THE BEN HOLT CO.	201 SO. LAKE AVE.	PASADENA, CA	91101	(213) 684-2541
HOSANG, GEORGE	SOLAR TURBINES INT'L	P.O. BOX 80966	SAN DIEGO, CA	92138	
HUETTEMEYER, H.F.	SO. CALIF. EDISON CO.	P.O. BOX 800	ROSEMEAD, CA	91770	(213) 572-2684
HUGHES, EVAN E.	ELECTRIC POWER RESEARCH INST.	P.O. BOX 10412	PALO ALTO, CA	94303	(415) 855-2179
IWAKI, TAMOTSU	KYUSHU ELECTRIC POWER CO, INC PHONE OP2P2-5-3431	3406-4 DAZAIFUMACHI	CHIKUSHI GUU, FUKUOKA KEN	JAPAN 818-01	
JACOBSON, WILLIAM O.	SAN DIEGO GAS & ELEC.	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7731
JAMIN, MARY E.	ROCKWELL INTERNATIONAL	2421 WEST HILLCREST DR.	NEWBURY PARK, CA	91320	(805) 498-6771
JASZBERENYI, ZOLTAN	A.W.I., INC.	P.O. BOX 638	SAN MARCOS, CA	92069	(714) 745-2022
JOHNSON, W.E.	WESTEC SERVICES, INC.	3211 FIFTH AVENUE	SAN DIEGO, CA	92130	(714) 294-9770
KENNEY, JAMES	SAN DIEGO GAS & ELEC.	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7731
KHALIFA, H. EZZAT	UNITED TECHNOLOGIES	RESEARCH CTR., M/S 79	EAST HARTFORD, CT	06108	(203) 727-7401
KHO, S.K.	PACIFIC GAS & ELECTRIC	77 BEALE ST	SAN FRANCISCO, CA	94106	(415) 781-4211
KLOOSTER, H. JOSEPH	FLUOR ENGINEERS & CONSTR.	3333 MICHELSON DR.	IRVINE, CA	92730	(714) 975-3515
KOHAN, STEPHEN M.	ELECTRIC POWER RESEARCH INST.	P.O. BOX 10412	PALO ALTO, CA	94303	(415) 855-2679
KRUGER, PAUL	CONSULTANT	819 ALLARDICE WAY	STANFORD, CA	94305	(415) 493-4284
KRUMLAND, LARRY R.	GIBBS & HILL, INC.	1754 TECHNOLOGY DR, #116	SAN JOSE, CA	95110	(408) 298-8020
LACY, ROBERT G.	SAN DIEGO GAS & ELEC.	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7754
LAFFOON, CARTHRAE M.	C.M. LAFFOON CONSULTING	P.O. BOX 1892	EL CAJON, CA	92022	(714) 440-7501
La MORI, PHIL	OCCIDENTAL RESEARCH	P.O. BOX 19601	IRVINE, CA	92713	(714) 957-7051
LARSON, TOD	SCIENCE APPLICATIONS, INC.	1200 PROSPECT ST.	LA JOLLA, CA	92038	(714) 454-3811
LEGORETA, ARMANDO	ZOMA GEOTERMICA DE CERRO PRIETO, MEXICALI, B.C., P.O. BOX 248 CALEXICO, CA			92231	
LI, KAM WAH	SAN DIEGO GAS & ELEC.	101 ASH ST.	SAN DIEGO, CA	92077	(714) 235-7877

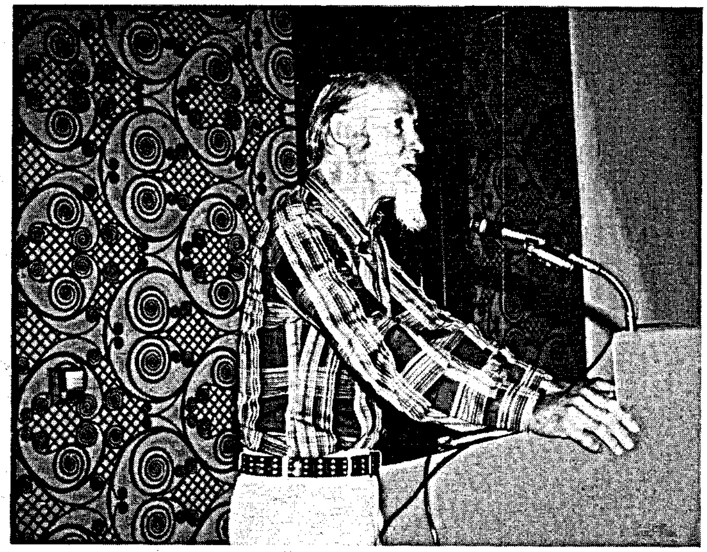
LONG, WILLIAM P.	O'BRIEN RESOURCES	104 AVERN WAY, SUITE 4	GRASS VALLEY, CA	95945	(916) 272-7203
MACY, ROBERT L.	SUNEDCO	12700 PARK CENTRAL PL.	DALLAS, TX	75251	(214) 385-5113
MADDOX, JACK D.	PUBLIC SERV. OF NEW MEXICO	P.O. BOX 2267	ALBUQUERQUE, NM	87158	(505) 848-4870
MAÑON, ING. ALFREDO	C.F.E.	P.O. BOX 248	CALEXICO, CA	92231	1-70-656-2-99-13
MASSIE, STEPHEN N.	PROCON INTERNATIONAL, INC.	50 UOP PLAZA	DES PLAINES, IL	60016	(312) 391-3538
MATTHEWS, HUGH	SPERRY CORP.	2017 ANDERHOLT	HOLTVILLE, CA	92250	(714) 356-4833
MAY, SHERMAN	BECHTEL	50 BEALE ST.	SAN FRANCISCO, CA	94127	(415) 768-3003
MC CLUER, H.K.	PACIFIC GAS & ELECTRIC	3400 CROW CANYON RD.	SAN RAMON, CA	94583	(415) 820-2000
MC CRACKEN, F.	SOUTHERN CALIF. EDISON	P.O. BOX 800	ROSEMEAD, CA	91770	
MC FARLAND, C.B.	U.S. DEPT. OF ENERGY		WASHINGTON, DC	20461	(202) 633-9471
MC NERNEY, KEN	BANK OF MONTREAL	P.O. BOX 7605, RINCON ANX.	SAN FRANCISCO, CA	9420	(415) 391-8060
MERCADO, SERGIO	INST. INVESTIGACIONES ELECTRICAS, P.O. BOX 475		CUERNAVACA, MOR., MEXICO	41433	
MICKLEY, MIKE	COURY AND ASSOC.	7625 W. 5TH AVE.	LAKEWOOD, CO	80229	(303) 232-3823
MORRIS, CHARLES W.	REPUBLIC GEOTHERMAL INC.	P.O. BOX 3388	SANTA FE SPRNGS, CA	90670	(213) 945-3661
MULVIHILL, ROBERT J.	PICKARD, LOWE & GARRICK INC.	17840 SKYPARK BLVD.	IRVINE, CA	92714	(714) 556-5200
MUNTOYA, JORGE	SAN DIEGO GAS & ELEC.	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7733
NESEWICH, P.	AEROJET ENERGY CONV.	P.O. BOX 13222	SACRAMENTO, CA	95813	(916) 355-2056
O'BRIEN, FRANK D.	TECHNADRIL-FENIX & SCISSON	3 NORTHPOINT, SUITE 200	HOUSTON, TX	77060	(713) 999-6464
PAGE, THOMAS	SAN DIEGO GAS & ELECTRIC	P.O. BOX 1831	SAN DIEGO, CA	92112	
PARKINSON, DAVID	WESTEC SERVICES	3211 FIFTH AVE.	SAN DIEGO, CA	(714) 294-9770	
PAUL, DHARAM	CENTRAL ELECTRICITY AUTHORITY	NEW DELHI	INDIA		
PERRY, V.A.	BECHTEL GROUP, INC.	P.O. BOX 3965	SAN FRANCISCO, CA	94119	(415) 768-7687
PHILBIN, EWING R.	THERMAL POWER/NATOMAS	601 CALIFORNIA ST.	SAN FRANCISCO, CA	94108	(415) 981-5700
POOLE, KIRBY	SOLAR TURBINES INT'L	P.O. BOX 80966	SAN DIEGO, CA	92138	
PRICE, R.E.	PACIFIC GAS & ELECTRIC	77 BEALE ST.	SAN FRANCISCO, CA	94106	(415) 781-4211
PROVINCE, S.G.	WESTEC SERVICES, INC.	3211 FIFTH AVENUE	SAN DIEGO, CA	92130	(714) 244-9770
PUNDYK, JOSEPH M.	PFR ENERGY SYSTEMS	4676 ADMIRALTY WAY #832	MARINA DEL REY, CA	90291	(213) 822-8620
RASBAND, J. LYNN	UTAH POWER & LIGHT CO.	P.O. BOX 899	SALT LAKE CITY, UT	84110	(801) 535-4281
RICE, LARRY F.	SYSTEMS, SCIENCE & SOFTWARE	P.O. BOX 1620	LA JOLLA, CA	92038	(714) 453-0060
RIDGWAY, JR., J.R.	HOUSTON LIGHTING & POWER CO.	P.O. BOX 1700	HOUSTON, TX	77001	(713) 481-7597
RINEY, T. DAVID	SYSTEMS, SCIENCE & SOFTWARE	P.O. BOX 1620	LA JOLLA, CA	92038	(714) 453-0060
ROBERTS, VASEL W.	ELECTRIC POWER RESEARCH INST.	P.O. BOX 10412	PALO ALTO, CA	94303	(415) 855-2179
SAMUELSON, JON	PLAINS ELECTRIC G & T	2401 ASTEC N.E.	ALBUQUERQUE, NM	87158	(505) 884-1881
SHEINBAUM, IKE	I. SHEINBAUM CO., INC.	136 WEST WALNUT AVE.	MONROVIA, CA	91016	(213) 357-9702
SHULMAN, GARY	GEOTHERMAL POWER CO.	1460 W. WATER ST.	ELMIRA, NY	14905	(607) 733-1027
SILVERMAN, MARC A.	SOHIO	1748 GUILDHALL BLDG.	CLEVELAND, OH	44115	(216) 575-6330
SIMMONS, D. EUGENE	HOUSTON LIGHTING & POWER	P.O. BOX 1700	HOUSTON, TX	77001	(713) 229-7263
SPARKS, THOMAS R.	SOUTHERN CALIF. EDISON	P.O. BOX 800	ROSEMEAD, CA	91770	(213) 572-2612
SPENCER, DWAIN F.	ELECTRIC POWER RESEARCH INST.	P.O. BOX 10412	PALO ALTO, CA	94303	(415) 855-2498
STAUDER, J.	BRITISH COLUMBIA HYD POWER	555 W. HASTINGS ST.	VANCOUVER, B.C.		(604) 663-2753

SUGINE, SAM S.	LOS ANGELES DEPT OF WATER&PWR	P.O. BOX 111, RM.1149	LOS ANGELES, CA	90051	(213) 481-8679
TENNEY, RUSS L.	SAN DIEGO GAS & ELEC.	P.O. BOX 1831	SAN DIEGO, CA	92112	(714) 235-7739
TURNER, JIM R.	IDAHO POWER CO.	P.O. BOX 70	BOISE, ID	83707	(208) 383-2200
TURPIN, FRANK	MORRISON-KNUDSEN CO., INC.	P.O. BOX 7808	BOISE, ID	83729	(208) 378-3709
UNITT, STANLEY G.	FLUOR POWER SERVICES, INC.	3333 MICHELSON DR.	IRVINE, CA	92730	(714) 975-4940
USSERY, MICHAEL A.	PUB. SERV. CO. OF N.M.	ALVARADO SQUARE, 6TH FL.	ALBUQUERQUE, NM	87158	(505) 848-2577
VOYTILLA, MIKE	DEPT. OF ENERGY	110 WEST A STREET	SAN DIEGO, CA	92101	(714) 235-7475
WALKER, M.J.	REPUBLIC GEOTHERMAL INC.	11823 E. SLAUSON AVE.	SANTA FE SPRNGS, CA	90670	(213) 995-3661
WATSON, PHILLIP C.	EUREKA ENERGY CO.	215 MARKET ST., RM 256	SAN FRANCISCO, CA	94106	(415) 781-4211
WEINRESS, JEFFERY B.	BANK OF AMERICA	555 SOUTH FLOWER ST.	LOS ANGELES, CA	90071	(213) 683-3995
WELCH, HARRY J.	TRANSAMERICA DELAVAL INC.	P.O. BOX 8788	TRENTON, NJ	08650	(609) 890-5420
WERES, OLEH	LAWRENCE BERKELEY LAB.	UNIVERSITY OF CALIF.	BERKELEY, CA	94720	(415) 486-5625
WHITBECK, J.F.	EG&G IDAHO INC.	P.O. BOX 1625	IDAHO FALLS, ID	83415	(208) 526-1879
WHITE, A.A.L.	MARCHWOOD ENGINEERING LABS.	MARCHWOOD, SOUTHAMPTON	HANTS, ENGLAND	SO44ZB	
	TEMPORARILY AT EPRI	P.O. BOX 10412	PALO ALTO, CA	94303	(415) 855-2487
WILBUR, ART	DEPT. OF ENERGY	110 WEST A STREET	SAN DIEGO, CA	92101	(714) 235-7475
WISTORT, ROBERT A.	H.K. FERGUSON CO.	180 HOWARD ST.	SAN FRANCISCO, CA	94105	(415) 442-6300
WITT, JAMES H.	ARINC RESEARCH CORP.	2551 RIVA ROAD	ANNAPOLIS, MD	21401	(301) 266-4703
YAMASAKI, ROGER	WESTEC SERVICES, INC.	3211 FIFTH AVE.	SAN DIEGO, CA	92103	(714) 294-9770

Photos taken during the Fifth Annual EPRI Geothermal Conference and Workshop in San Diego, June 1981, by John R. Ridgway, Jr. of Houston Lighting & Power Co.





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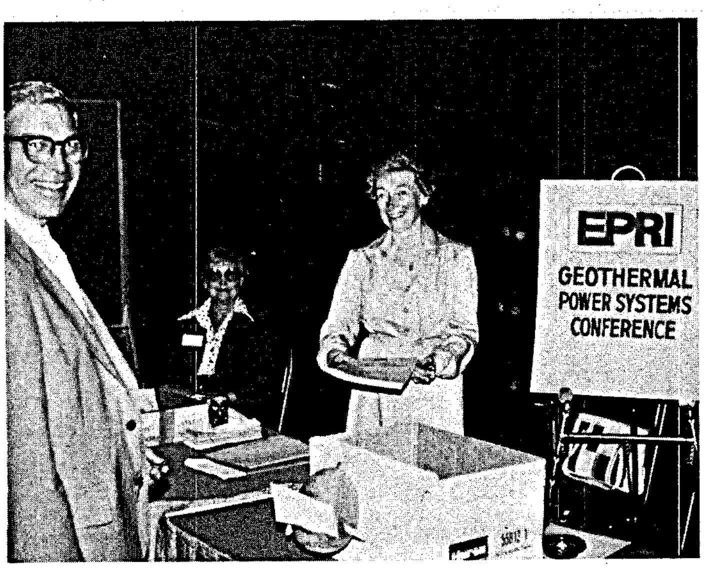
EPRI
GEOTHERMAL
POWER SYSTEMS
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AUTHOR INDEX