Proceedings of the Fourth Annual Geothermal Conference and Workshop

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Prepared by
Altas Corporation
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Proceedings of the Fourth Annual Geothermal Conference and Workshop

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Special Study Project TC-80-907

Conference Proceedings, December 1980

June 24–26, 1980
Monterey, California

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Prepared by
Altas Corporation
Santa Cruz, California

ABSTRACT

These proceedings are a reflection of the business of the Fourth Annual Geothermal Conference conducted by the Electric Power Research Institute which was held at the Del Monte Hyatt House in Monterey, California, during June 24 - 26, 1980. Earlier meetings were held in Oregon, 1977; Taos, New Mexico, 1978; and Monterey, California, 1979.

Objectives of this conference were to exchange information and experience on U.S. and international geothermal power plant development, to present EPRI's program and project results, and to report utility projects and plans.

PREFACE

Amid shakey reliance on imported oil, clamor for resolution of nuclear power issues, and urging of a coal-based energy economy, the development of geothermal energy is moving quietly, almost unnoticed, and without fanfare into an exciting and more mature phase. Generation of commercial power from hydrothermal (hot water) resources is approaching reality. For the first time in the United States, electricity generated from "hot water" geothermal resources was delivered to an electric power grid in 1979. The honor of this achievement went to the Magma Power Company and its East Mesa, California, binary cycle pilot plant. Union Oil and Southern California Edison's direct-flash pilot plant at Brawley is not far behind. It is expected to start delivering power to the electric grid sometime in 1980. Other hydrothermal plants are in various stages of design and planning, and the number is increasing.

The Geysers project in northern California now has an installed capacity of 800 MW(e) based on natural geothermal steam. As the capacity continues to grow and as hydrothermal power plants come into being, R&D planners are beginning to think more about improvements for the second generation of geothermal power plants. A number of engineering problems still remain, and the need for improvement is dictated by economics, increased environmental acceptability, and a need for better performance and resource utilization. Even before the paint on the first hydrothermal plant was dry, the challenge to improve the technology was clear, and the opportunity to observe, measure, and analyze the first generation as a prerequisite for improving future systems was obvious. It seems incumbent upon the industry to learn as much as possible from the first generation of geothermal power plants to assure that subsequent plants are more efficient, environmentally acceptable, and economically competitive with other energy sources. It was with this idea in mind that "Learning From Power Plant Project Experience" was selected as the theme for EPRI's Annual Geothermal Meeting this year. The main objective of the workshop was to examine progress of several of the more mature power plant projects. A second objective was to examine the key issues that are faced by commercial geothermal power plant projects and, finally, to examine power plant progress on the international scene.

In the past, EPRI's Geothermal Conference and Workshop has been intended as a way of sharing the results of EPRI-sponsored research with industry, of exchanging results of utility-sponsored in-house research, and of addressing one or more key issues of current interest. This same approach was used this year. As the number of utilities with specific interest in geothermal power plant projects increases, the importance of this kind of interchange of ideas also increases.

Vasel Roberts, Project Manager
Advanced Power Systems Division

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SESSION 1

OPENING

The following were presentations at Session 1 however there are no transcripts available for publication.

Welcome Address
David D. Tillson, Washington Public Power Supply System
Chairman, EPRI Geothermal Program Committee

EPRI Perspective
Vasel W. Roberts, Program Manager

John E. Cummings, Department Director

Keynote Address
Gary Cotton, Vice President of Engineering
San Diego Gas & Electric Company

SESSION 2

SPECIAL REPORT ON BACA PROJECT

BACA GEOTHERMAL DEMONSTRATION

POWER PLANT PROJECT

SPECIAL REPORT

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The objectives of the Project, in support of the 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 Project will be an integrated commercial-scale geothermal electric power generating plant which utilizes a liquid-dominated resource. As such, it will include 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.

In keeping with the Project objectives cited above, the Project will make use of existing technology to the maximum practicable extent, and no requirement for significant development of new technology is anticipated.

The Project organization is shown in Figure 1.

The Project Work Breakdown Structure (WBS) is shown in Figure 2 entitled "Geothermal Demonstration Power Plant Work Breakdown Structure." There are three major WBS elements. WBS 1.1 is the Well and Steam Production System. WBS 1.2 is the Power Plant and Transmission System. These WBS elements are Union's and PNM's responsibilities respectively on the Project. WBS 1.3 is the Data Gathering, Evaluation, and Dissemination Task delegated specifically to Participant.

We would like to review three areas of the Project with you: WBS 1.2.1 Environmental Studies & Permits, WBS 1.2.2 Power Plant Design & Construction, and WBS 1.3 Data Gathering, Evaluation & Dissemination. Mr. Dave Sabo, PNM's Environmental Coordinator, will review developments under WBS 1.2.1 entitled "Environmental Considerations for a Geothermal Development in the Jemez Mountains of Central New Mexico," Mr. John Bouma, Bechtel Project Manager, will review the design engineering aspects of the power plant in "Shaping A Geothermal Power Plant," and Mr. Pete Sherwood, WESTEC Data Task Manager, will discuss WBS 1.3, "The Baca Data Dissemination Program."

FIGURE 1

GEOTHERMAL DEMONSTRATION POWER PLANT
PROJECT ORGANIZATION

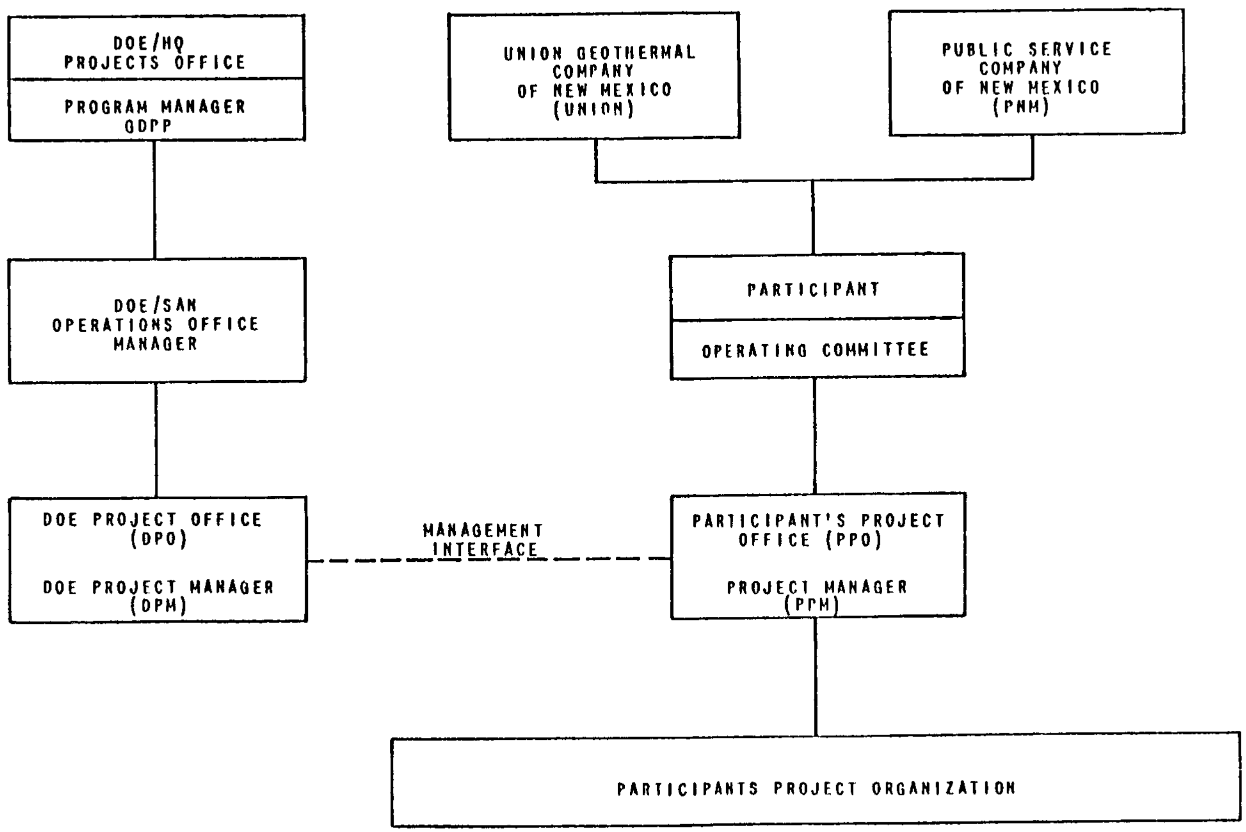
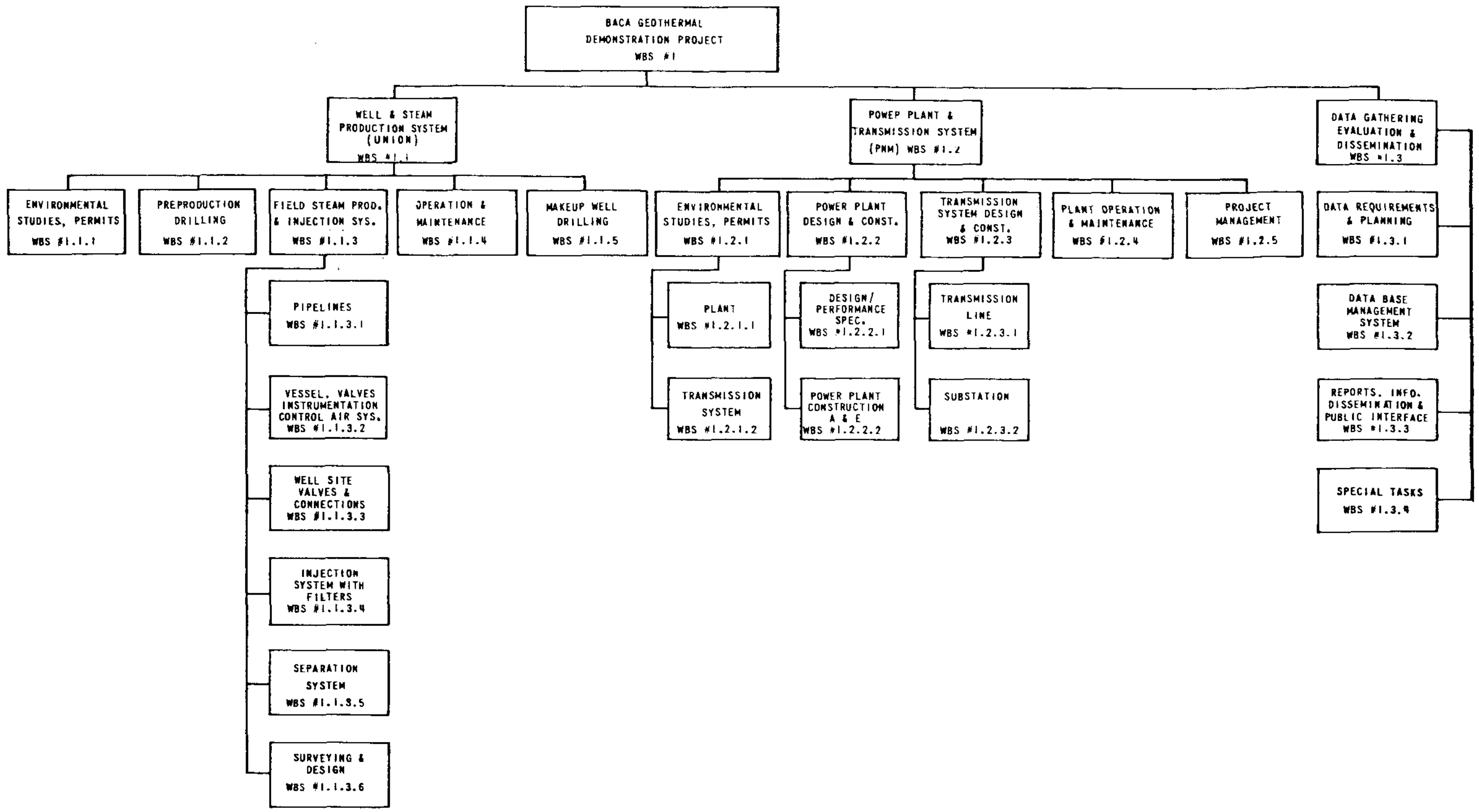


FIGURE 2

GEOTHERMAL DEMONSTRATION POWER PLANT
WORK BREAKDOWN STRUCTURE



ENVIRONMENTAL CONSIDERATIONS FOR A GEOTHERMAL DEVELOPMENT IN THE JEMEZ MOUNTAINS OF CENTRAL NEW MEXICO

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The demonstration nature of the Baca Geothermal Project and the contractual arrangements between Public Service Company of New Mexico (PNM) and Union Geothermal Company of New Mexico (Union) with the Department of Energy mandate on environmental monitoring effort previously not seen for an energy development of this size. One of the most often stated goals of the Baca Project is to demonstrate the acceptability and viability of geothermal energy in an environmentally responsible mannner. If this statement is to be followed, then a program would have to be developed which would (1) identify all the environmental baseline parameters, (2) monitor them during construction and operation, and (3) alleviate any possible negative impacts. The situation of the Baca Project in the Jemez Mountains of north-central New Mexico offers a challenging vehicle with which to demonstrate the acceptability of geothermal energy. A few of the reasons for this are: these mountains are one of the most heavily used recreational resource areas in the state, numerous prehistoric people utilized the canyons and have left considerable archeological resources, the mountains are home for a number of individuals who prefer their serenity to the hustle and bustle of urban dwelling, and finally, the mountains are considered sacred by a number of local Indian tribes, a few of which use the mountain top as religious sites.

Both energy development companies and the Department of Energy share a common goal, that is to develop this resource but at the same time, to preserve and protect the environment as much as possible. To some this may sound mutally exclusive, but we believe that this goal can be attained. I will elaborate on this.

First let me give you an environmental overview of the Jemez Mountains.

The mountains rise up from a semiarid desert grassland around its flanks at 5,300 feet to over 10,000 feet in elevation. The hills around the base grade rapidly from the grassland and juniper savanah to heavy conifer forests. The vegetation types found here, besides the grassland and savanah, are pinon-juniper associations, a yellow pine zone, a mixed conifer zone, and finally, a spruce-fir forest near the top.

Streams are abundant and the New Mexico Game and Fish Department stock these with rainbow and brown trout. Some of the more remote waterways have good populations of native cutthroat trout.

These mountains also harbor large populations of big game including mule deer, elk, bear, and mountain lions. Wild turkeys and grouse may also occasionally be found.

As might be expected, the Jemez mountains receive significant amounts of visitor usage from the nearby cities. People from Albuquerque, approximately 45 miles away, probably are in the vast majority but even closer are the cities of Santa Fe, Espanola, and Los Alamos. This places over 500,000 people less than one hour driving time away from these mountains. Visitors go for the hunting, fishing, backpacking, camping, or just to commune with nature. Whatever their reasons, many individuals do go into this area and they are all concerned with the future of the Jemez Mountains and the potential impacts geothermal development may have on them.

At the summit of the Jemez is a very large volcanic caldera approximately 17 miles across, most of which is included in the privately owned Baca location 1. Within this caldera are three large meadows (Valles as they are called in Spanish), the most famous of which is the Valle Grande which many travelers drive into the Jemez Mountains just to see.

In the southwest corner of the Baca location are a number of small valleys which exhibit geothermal characteristics. The landowner drilled a few geothermal test holes in sulfur canyon. He then leased the entire Baca location to Union Geothermal Co. of New Mexico for exploration and possible development. The development is at hand and will occur just to the south of the original test well in Redondo Canyon.

This canyon is situated below Redondo Peak, one of the highest points in the Jemez. It has a small perennial stream running its entire length. The stream eventually makes its way to the Jemez River, the largest and most heavily used stream in the mountains. The canyon is quite small, but houses large numbers of elk and other wild game. Also found in this canyon is the only known endemic species in the area, the Jemez Mountain Salamander. This salamander is listed as a threatened species by New Mexico Game and Fish on their state list. It has not been listed by U.S. Fish and Wildlife Service but was considered. To complete the picture of this overview, an occasional peregrine falcon is also seen here periodically,but none are known to be nesting in close proximity to the proposed plant site.

In the mid-1970's Union Geothermal initiated exploratory drilling and in a simultaneous effort, undertook some environmental studies to gain a baseline on the area prior to any large scale development. Included in these studies were water quality, both surface and shallow aquifer, limited air quality and meteorology, and biotic (including endangered species, big game, and vegetative mapping).

When it became apparent that PNM and Union were going to begin development of this resource, the original studies were greatly expanded and new studies initiated. New studies included land-use, socioeconomics, archeologic, stream ecology, soils, and computer graphics to study impacts of the power plant plume and the transmission line.

Various studies to identify possible transmission line routes were undertaken. Possible routes were carefully screened in a type of sifting process to find the best routes from an engineering and environmental perspective.

As the final routes were being scrutinized, PNM conducted state-of-the-art predictive archeologic surveys and visual computer mapping to further assist in final route selection. The predictive archeological survey identified zones of density for the resources in the whole mountain and the visual mapping identified the least visible points for positioning the T-line.

All of these studies plus additional environmental data were utilized by DOE in the preparation of their Environmental Impact Statement. From a number of alternatives in the EIS, a final routing of the T-line was defined and should serve as a model in planning.

With the final approval of the Department of Energy's EIS and a Record of Decision to proceed with the Project, a new phase begins in the Environmental Programs. The previous studies offer an excellent baseline; now the actual construction impacts must be identified and monitored. The participants (PNM/Union) proposed a plan for DOE which included more monitoring of the previously named programs. DOE also indicated the need for expanded programs beyond that which would normally be conducted for a plant of this size. To accomplish this, a data subcontractor (Westec Services Inc.) was selected. They will supply additional environmental monitoring, not of a redundant nature, but studing critical components to a greater degree.

A brief review of the current monitoring program would be appropriate.

AIR/METEOROLOGY

Introduction The Ambient Air Monitoring Program for the Baca Project has been contracted to Western Scientific Services, Inc. (WSSI), a subsidiary of Environmental Research and Technology, Inc. Work done by WSSI is administered by Ralph Williams of PNM.

Methods and Materials Four monitoring units will comprise the air monitoring network: Stationary Units 1 and 2 and Mobile Units 3 and 4.

Station 1 will be located about 100 yards to the northeast of the proposed power plant site and will consist of:

A. A 200-foot meteorological tower carrying the following:

    1. Telemetry gear for recording and transmitting data received from mobile Units 3 and 4.

    2. Windspeed recorders at 10m, 30m, and 60m.

    3. Temperature recorders at 10m, 30m, and 60m.

    4. Recorders of temperature difference between 10m and 60m.

    5. Dewpoint recorders at 10m, 30m, and 60m.

    6. Solar radiation recorder at 10m.

    7. Precipitation recorder at ground level.

B. Air chemistry analyzers that include:

1. One meloy H_2S analyzer (285E).
2. Two flow controlled TSP hi-volume samplers.

C. Support equipment for station which will include the following:

1. Heated/air conditioned shelter.
2. Air sampling manifold.
3. Instrument racks.
4. Monitor labs data logger (9300).
5. Kennedy Model 9800 9-track recorder.
6. Telemetry receiver and antenna.
7. Sola voltage regulator.

Station 2 will be located near the mouth of Redondo Canyon. It will be the site for the acoustic sounder furnished by PNM. It shall include:

A. Aerovironment Mono-static Acoustic Sounder

1. Antenna assembly: fiberglass parabolic reflector, transducer, and acoustic enclosure.
2. Preamplifier.
3. Transmit/receive and signal conditioning control unit.
4. Recorder.
5. Interconnecting power lines and cables.

B. Support Equipment

1. Shelter with heat and air conditioning.

Mobile Unit 3 is a moveable monitoring stations consisting of:

A. Meteorological equipment

1. One (1) 30-foot meteorological tower.
2. One (1) wind direction sensor at thirty (30) feet.
3. One (1) wind-speed sensor at thirty (30) feet.

B. Air Chemistry Equipment

1. One (1) meloy H_2S analyzer (285E).
2. One (1) flow controlled TSP hi-volume sampler.

C. Support Equipment will Consist of:

1. Heated/air conditioned shelter.
2. Propane operated generator 15 kW (for sites where power is not available).
3. Air sampling manifold.
4. Instrument rack.
5. Telemetry scanner and transmitter.
6. Three (3) single-channel strip chart recorders.
7. Sola voltage regulator.

Mobile Unit 4 is a moveable monitoring station consisting of:

A. Meteorological equipment.

1. One (1) thirty (30) foot meteorological tower.
2. One (1) wind direction sensor at thirty (30) feet.
3. One (1) wind-speed sensor at thirty (30) feet.

B. Air Chemistry Equipment

1. One (1) meloy H_2S analyzer (285E).
2. One (1) flow controlled TSP hi-volume sampler.

C. Support Equipment

1. Heated/air conditioned shelter.
2. Air sampling manifold.
3. Instrument rack.
4. Telemetry scanner and transmitter.
5. Sola voltage regulator.

Additional Air Monitoring Additional programs run by PNM through WSSI include a 15 location H_2S tab program and a program of pilot ballon mini-sonde launches. The mini-sondes are launched twice per day for three week periods each quarter of year.

WATER QUALITY MONITORING

Introduction Extensive monitoring on Redondo Creek at a site below Baca Well 12, which is effectively down stream from both plant site and well field will assess water quality impacts due to the project.

A less extensive watershed monitoring program will provide information on what, if any, effect impacts on Redondo Creek have in the watershed.

Purchase of equipment, data reduction, and field work related to watershed monitoring will be supervised by Lyle Rae Berger of Union. Maintenance of Redondo Creek sampling station will be conducted by a technician; water analysis will be conducted by Albuquerque Assay Laboratories.

MEHTODS AND MATERIALS

Redondo Creek Monitoring The Redondo Monitoring Station will include:

1. A parshall flume for flow measurement.

2. Monitors and recorders for flow, pH, and temperature.

3. Composite sampler for water chemistry samples.

4. A small shelter to house equipment.

Such a monitoring system will require daily checking by a technician who would also be responsible for logging of construction activities and pertinent weather conditions.

Water quality samples will be taken on a flexible schedule and transported to Albuquerque Assay Laboratory for analysis.

Watershed Monitoring About 12 grab samples should be taken at each of six sites in the Jemez Watershed throughout the year on a flexible schedule. Field notes at each sample site should include pertinent weather conditions, field pH, conductivity, temperature, and flow rate. All samples will be transported to Albuquerque Assay Laboratory for analysis. Samples will be collected in bottles supplied by the laboratory and field prepped according to lab instructions.

Initially analysis should include the following:

1. Specific Conductance
2. pH
3. TDS
4. TSS
5. As
6. HCO_3
7. CO_3
8. B
9. Ca
10. Cl
11. F
12. Fe (total and dissolved)
13. Mg
14. Hg
15. NO_3
16. NO_2
17. PO_4
18. K^{+}
19. SiO_2
20. N_a^{+}
21. SO_4^{-2}
22. S
23. Oil and Grease
24. BOD_5

This list may be revised as information from previous analyses become available.

HYDROLOGY

Introduction Union will administer a geothermal groundwater monitoring program separate from Surface Water Monitoring. This monitoring will evaluate the effects of withdrawal of geothermal fluids from the Caldera reservoir on regional groundwater. The groundwater monitoring program will follow the New Mexico State Engineer's program established in 1975.

Water Resources Associates, Inc. (WRAI) has been contracted by Union to collect data and administer analysis of samples. A field technician and all equipment will be supplied by WRAI. Lyle Rae Berger of Union will administer the hydrology program.

Methods and Materials Eight to ten water quality sampling sites will be established; four to five springs will be measured for discharge; and seven to ten wells will be measured for water level (outside production area).

Sample collection will concentrate on springs and wells to the West and South of the Baca Project with additional selected sample sites located on the Baca Ranch lands.

The following springs will be sampled for discharge measurements and water quality analysis:

1. McCauley Hot Springs (USFS)
2. San Antonio Hot Springs (two sample sites)
3. Soda Dam (two sample sites)
4. Spense Spring
5. Sulfur Springs
6. San Antonio Warm Springs located on Baca Ranch

The followng wells will be measured for water depth:

1. Glass Well--privately owned, located on Thompson Ridge.
2. Three (3) Hofheins Wells--privately owned, located at La Cueva.
3. Forest Service Well--located at Horseshoe Springs.
4. Four Los Alamos Scientific Laboratory geothermal temperatures test Wells A, B, C. D.
5. Baca Ranch Wells--previously tested.

AQUATIC ECOLOGY STUDY

Introduction PNM and Union will contract a continuous aquatic ecology survey with Mr. Steve Ziser of the University of New Mexico. The study may be renewed for years during and after major construction activities.

Methods A minimum of three collecting sites will be chosen within the study area with the following parameters being investigated:

1. The physico-chemical characteristics of water velocity/discharge, dissolved oxygen, free carbon dioxide, carbonate and bicarbonate alkalinity, conductivity, water temperature, turbidity, suspended solids, dissolved solids, pH, total nitrogen, and total phosphorus will be measured according to standard limnological procedures.
2. Stream substrate diversity as an important factor in regulating the distribution and abundance of the aquatic fauna will be measured by mapping substrates according to size of the exposed surfaces. Five replicate square foot areas will be mapped at each sampling site. An index of substrate diversity will be calculated for each site (Shannon and Weaver 1963).
3. Aquatic macrophytes will be identified to species from collections made at each site.
4. Major components of the periphyton community will be identified to genus.
5. Special attention will be given the aquatic macroinvertebrates at each site. Two square foot surber-type samples will be taken at each location and aquatic insects and other macroinvertebrates will be identified to the family and/or genus level.
6. Aquatic vertebrates, particularly fishes will be seined at each station and identified to species.

TERRESTRIAL ECOLOGY

Ava fauna Due to the variety of vegetation and elevation within the plant site study area, avian diversity is expected to be high. Four habitats occur within the study area. These will be sampled utilizing field procedures described by Emlen (1971) and data analysis described by Balph et al. (1977). The following is a summary of the field procedures:

1. A transect of X meters will be established in each habitat.
2. These will be walked three consecutive days in spring, summer, and fall.
3. Each bird will be identified and the lateral distance from the transect line will be recorded.

During the course of the general reconnaissance and the other portions of the biotic monitoring program, a list of species occurring in the different habitats will be compiled. As a measure of species diversity, the Shannon-Weaver measure will be computated for each habitat.

Small Mammals Small mammals will be sampled twice each year. These census periods will occur in spring before the major reproductive effort and again late in the summer to early fall after reproductive recruitment. Biologists will utilize a catch per unit effort-sampling technique based on 300 trap nights per trapping session in each habitat. Transects will be preferentially located in the four habitat types within the study area. Two 250-meter transects will be laid out approximately 200 meters apart in each census area or one 500-meter transect depending on the shape of the habitat. Along each transect, 25 trap stations will be located at ten yard intervals. Each station will have one live trap for a total of 50 traps per census area. These transects will be baited with oatmeal. They will be checked each morning and, if necessary, reset and rebaited. All captured animals will be identified to species and released.

During the course of the general reconnaissance and the performance of the other portions of the biotic monitoring program, a list of species occurring in the different habitats will be compiled. Species diversity will be calculated for each habitat type according to the Shannon-Weaver equation.

Large Mammals Two species of wild ungulate occur within the study area. These are the elk and mule deer. Methodology to be used is that described by Neff (1968) and Smith et al. (1969). Four transects of 625 plots each will be established in and near the study area. This sample size was determined utilizing the formula given by Overton (1969).

Essentially, there will be 600 plots spaced 20 feet apart in each transect. This will result in four transects. Two transects will be located on the east and two on the west side of the canyon.

These plots will be read in the spring after the snow melts (i.e., April, May) then 120 days later in spring and again 120 days later in November or December or before snows would cover the plots.

Flora The floral monitoring program will expand the considerable amount of floristic information already available to complete the picture in Redondo Canyon. With this work complete prior to actual startup of the generation station, any modification of the ecosystems will become evident with continued monitoring of the project area.

The following is a summary of the field procedures.

1. The vegetation will be extensively collected and identified.

2. Seventeen study plots (30 x 30m) will be delineated in which studies to determine changes in density and frequency. Each of the 30 x 30m plots will be divided into 100 3 x 3 sections of which one-half randomly selected plots will be analyzed.

3. The existing mammal transects will be utilized for overall study of the entire canyon. Each transect consists of 600 points of which every 24 point will be utilized as floral monitoring point. This will give 25 points to a transect or 100 points in total. The point quarter method of analysis will be applied. This should show changes in the forest composition over time.

In addition to the PNM/Union Monitoring Program, Westec Inc., the DOE data-subcontractor, will be performing complementary and supplementary analysis on three of the principal components, Air, Biota, and Water Quality.

In summary, the Baca Project hopes to fulfill the desired goals in the original Project Opportunity Notice (1977) which announced this Geothermal Project, that is to accelerate the commercialization of geothermal energy in an environmentally sound manner.

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SHAPING A GEOTHERMAL POWER PLANT

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INTRODUCTION

The design comprises a "grassroots" geothermal steam electric generating plant located approximately 34 miles west of the city of Los Alamos.

The plant is located on the Baca Ranch in the Redondo Creek area some 4-1/2 miles north of the southwest entrance of the ranch. This plant will utilize the geothermal brine well system that has been explored by the Union Geothermal Company of New Mexico.

The gross plant capacity will be approximately 50,000 kW and will not be expanded since well gathering beyond a 50 MW generating capacity is considered uneconomical. The plant is generally comprised of four (4) major building blocks, namely the power building, the cooling tower and intake structure, the switchyard and the H_2S abatement system.

Some twelve (12) alternatives were studied for economic and technical feasibility. In addition some innovative design concepts were applied to arrive at a functional and cost effective design.

The plant incorporates a hydrogen sulfide emission abatement system, the design of which has been guaranteed by the equipment manufacturer to meet the specified emission limits.

PLANT SITE ARRANGEMENT

Relative Position of Major Plant Components

In deciding on the space requirements, location and orientation of the major plant components, maps of the particular area under consideration were used.

In arranging the major plant components, which are the cooling tower, power block, switchyard and the H_2S abatement system, the following factors are considered:

- The available level ground space.
- Wind direction with respect to cooling tower location.
- The assigned site location.
- Best relative location of power block, cooling tower, switchyard and H_2S abatement system.

Service water storage is near the power block to provide moderate storage for the service water supply system.

Supply for the firewater system is from the cooling tower basin. Motor driven firewater pumps are located in the power block.

Plant sewage disposal equipment is located immediately adjacent to the Plant West boundary.

Disposal of cooling tower blowdown and excess condensate will be made via the Plant West boundary to Union Geothermal.

POWER BUILDING ARRANGEMENT

The development of the power building is based on the dimensions of the turbine generator and its components laid down on the operating deck during a major unit overhaul as well as the space requirements of the auxiliary equipment at the ground floor elevation.

The auxiliary equipment is mainly located on the ground floor with a small portion of the equipment located on the mezzanine level. The auxiliary equipment arrangement that has been achieved provides an almost perfect balance between the building space requirements for auxiliary equipment at the ground floor and the turbine generator equipment laydown space requirements at the turbine floor.

The first stage air ejector equipment is located at the mezzanine level for reasons of keeping the large size air off-take piping short and enhance dumping the discharge into the ejector inter-condenser mounted at ground level.

The levels of the ground floor, mezzanine and operating floor are set at 15 ft intervals. This requirement is mainly dependent on the height of ejector condenser and space to permit their removal if maintenance is required in the future.

Each floor level can be reached by two separate stairways, one at each end of the power building.

Operator traffic through the plant is accomplished by adequate walkways throughout the ground floor level and adequate platforms and walkways at the mezzanine level.

To accommodate maintenance of the condenser and the ejector condensers tube pulling can be accomplished through removable wall panels to the outside. This design feature is commonly applied by Bechtel on numerous plants and results in functional tube pulling without having to add valuable building space.

SUPPORTING FACILITIES

Location and space allowances for supporting facilities for the major equipment have been treated as follows:

Turbine

The auxiliary equipment of the turbine

consists of the turbine lube oil reservoir, lube oil coolers, lube oil conditioner, and the Electro-Hydraulic Control Unit. This equipment has been located in front of the turbine pedestal columns.

The turbine oil storage tanks (dirty and clean) and the transfer facilities have been eliminated for the following reason. The oil change is a function of regular maintenance and the oil change can be accomplished by ordering this service from an oil refining company. This approach has been practiced before for much larger units, and a small-generating unit can be operated successfully without incurring the cost burden of this storage and transfer facility.

Condenser and Ejector Condensers

The condenser and ejector condensers have been arranged for a two-pass flow pattern. This design permits inlet and outlet connections to be located on the same end of the heat exchangers; hence the large cooling water lines from the cooling tower can be located on one side of the turbine pedestal and can be kept short.

The ejector condensers have been kept in close proximity to the main condenser in order to keep the large piping runs minimal.

Also the large piping for gas extraction from the condenser is kept as short as possible. This is accomplished by splitting the gas extraction lines inside the condenser into four (4) lines of 18 inches each. These lines penetrate the condenser dome at the supply water box end in a box-type header arrangement.

Ejectors

From the condenser the gas extraction lines are routed to the primary steam ejectors which are mounted on the mezzanine and their discharge is dumped into the inter-condenser. Gas transfer from the inter- to after-condenser is accomplished by two (2) secondary steam jet ejectors which also raise the gas pressure above atmospheric pressure in order to send the remaining noncondensibles to the H_2S abatement system via a 12-inch transfer line.

Electrical Equipment

The generator circuit breaker is located in the switchgear room on the mezzanine floor to allow for a straight run of bus-duct from the generator.

All switchgear and motor control centers, except the H_2S motor control center, are placed in the switchgear room adjacent to the generator breaker on the mezzanine floor and directly below the control room. The H_2S motor control center is located in a clean room in the H_2S abatement system area.

The switchgear room is a part of the clean room concept and is provided with filtered ventilation air to minimize H_2S attack.

The battery room is located at the south side of the building on the mezzanine floor, adjacent to the switchgear room. This room will be mechanically ventilated to outdoors. The station battery will be sized to accommodate both station and switchyard loads.

The standby diesel generator set is located in the southeast corner of the building on the grade elevation below the switchgear room. The plant south wall will be provided with louvers for cooling air to the engine radiator.

All the above locations minimize the requirements for cabling and raceway.

The transformers are placed as close to the power block as feasible and are positioned to use the power building as a baffle to cooling tower mist to minimize coating of the equipment insulators.

Compressed-Air System

The compressed-air system for this unit consists of two nonlubricated teflon ring compressors with a single receiver. This system and its associated drying and filtering facilities are used for service air as well as instrument air requirements. Both instrument and shop air is dried to minimize moisture problems.

The installation is located south of the main condenser.

Service Water

The service water storage tank is located outside near the southwest corner of the power building.

The service water pumps are located along the south wall of the power building; however, these pumps are located inside the building.

Fire Water

The electric driven fire water pumps are located inside in the northwest corner of the power building.

MAINTENANCE FACILITIES

The power building is equipped with a bridge crane having a main hoist capacity of 40 tons and an auxiliary hoist capacity of 10 tons. This crane is capable of serving the turbine generator and other associated equipment. In addition, a maintenance shop and warehouse bay have been provided in the design.

Equipment Removal Opening

The location and size of the equipment removal opening are based on the governing requirements of the turbine generator and were so placed to provide easy access upon plant site entry.

EQUIPMENT LAYDOWN FOR MAJOR OVERHAUL

Equipment laydown area requirements have been given full consideration in the overall design of the plant. Drawings of turbine-generator components were used to establish the adequacy of the operating deck for an organized and effective component laydown. The operating deck has been been designed to support turbine laydown loads.

Laydown space requirements have been provided for the following:

- Major Turbine Components
- Major Generator Components
- Space Allocation for Miscellaneous Turbine-Generator Parts
- Space Allocation for Cable Sling Laydown
- Space Allocation for Tool Room
- Space Allocation for Small Parts
- Space Allocation for Work Benches for Turbine Area and the Generator area

The turbine rotors can be located at grade in the equipment removal area so that temporary canvas partition walls can be placed around them to allow sandblasting of the blading, should that be necessary.

OPERATING FACILITIES

The control room is located on the turbine operating level at the southeast corner of the power building.

The control room is provided with a bench-type console for starting, monitoring, and shutdown of the turbine-generator as well as for startup and control of the balance of plant equipment.

A vertical auxiliary board serves the switchyard, miscellaneous balance of plant equipment, turbine-generator supervisory instrumentation, miscellaneous instrumentation, and protective relaying. Rear access to the panel is from the relay room. Both the control room and adjacent relay room are provided with filtered conditioned air to minimize H_2S attack.

The plant fire protection system monitor panel is also located in the control room.

DESIGN HIGHLIGHTS

General

During the evolution of the detail design, certain particular circumstances or conditions impacted the design; sometimes with adverse effects and sometimes these adverse effects have been turned around through innovative design and have resulted in advantageous design concepts.

Certain concepts foreign to conventional steam power plant design have been introduced to cope with the presence of hydrogen sulfide.

The extensive use of fiberglass reinforced plastic pipe is also a throw-off of the presence of H_2S.

H_2S distribution in the cycle is discussed and its concentrations leaving the cooling tower stack as well as the end products leaving the H_2S abatement system.

In addition, other points of interest in the course of the design are discussed as follows:

Effect of Site Development on Circulating Water Pump and Condenser

The development of the site had an interesting effect on the location selection of the circulating water pump at the Baca plant.

In turn, the location selection of this pump had an advantageous effect on the final design of the condenser respective to its ability to collect the hydrogen sulfide containing condensates as further discussed herein.

The geographic location caused the power plant to be built in part against a hill, being the assigned power plant site on the privately owned Baca Ranch.

Notwithstanding the problems encountered by the hillside location, the following gains were made during the evolution of the Baca design:

- To effect an economical site layout, two levels were developed, one for cooling tower and one for power plant, H_2S Abatement and Switchyard. The difference in the two levels, approximately 20 ft., enhanced locating the circulation water pump inside the power building and provided the pump with some 20 ft. of static suction head resulting in ample available NPSH.
- The vertical, mixed flow, circulating water pump was made an integral part of the circulating water conduit to the condenser and placed inside the power building. The otherwise separate pump structure and associated support facilities were eliminated and the intake structure was substantially simplified. This design approach resulted in the most economical pump arrangement.
- Another advantage of this design is that the system is self priming and pump operation is precluded until complete priming has been accomplished. Consequent hydraulic transients or bumps are constrained or kept minimal.
- The pump being inside the pump building facilitates maintenance and pump overhaul.
- Space requirements for housing the pump are minimal as a result of making the pump part of the circulating water conduit.
- The waste heat of the pump motor provides part of the power building heat in the winter time.

- The location of the pump forced a high inlet connection on the condenser. This condition was optimized by the condenser manufacturer who devised a steam path and gas path inside the condenser permitting the collection of the H_2S gas laden condensate on trays in the upper part of the condenser. This condensate can be kept separate from the hotwell condensate and, if necessary, it can be returned directly to the reinjection system thereby keeping the cooling tower makeup of the lowest H_2S concentration possible.

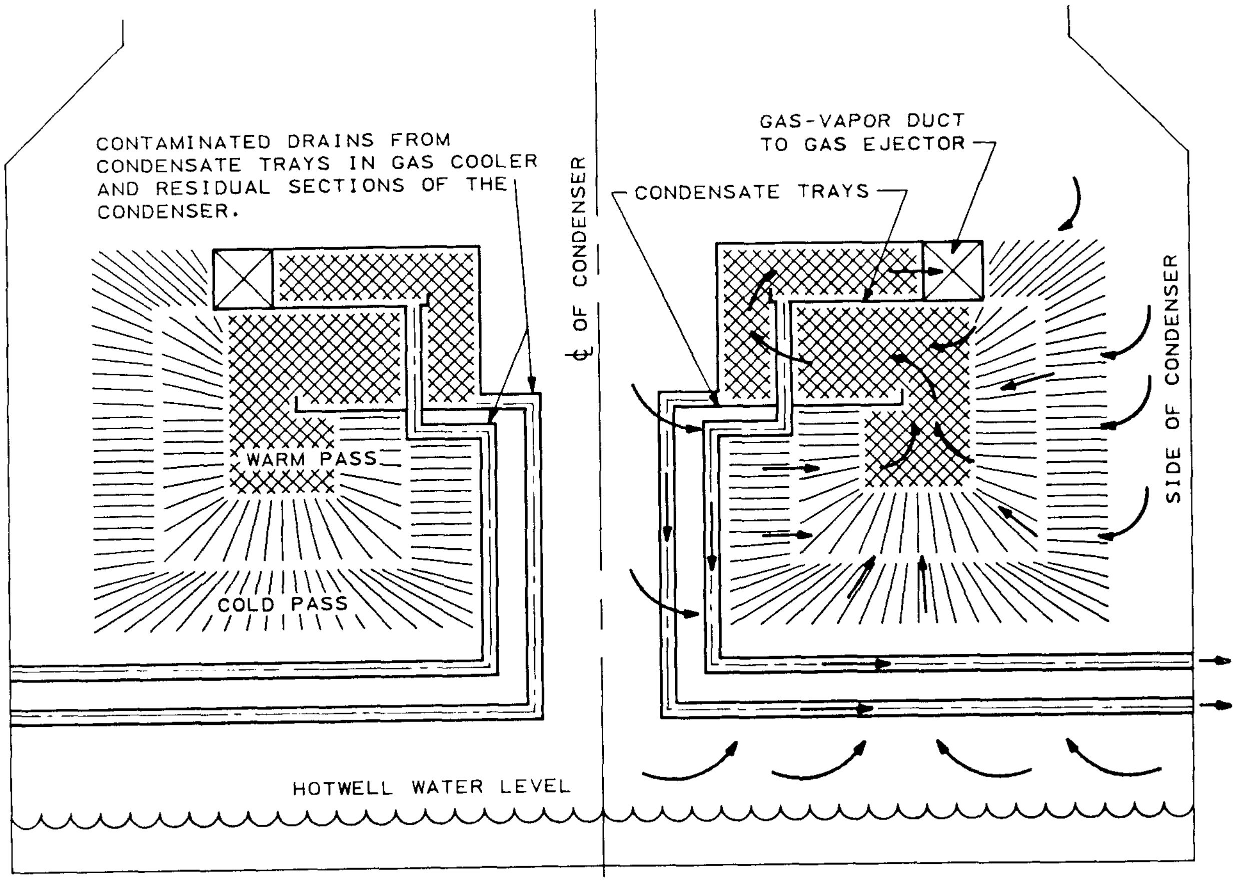
Surface Condenser

The purpose of this special design of geothermal surface condenser is to employ features which will limit and reduce, as much as possible, the tendency for the hydrogen sulfide to go into the condensate in the main condenser.

The sketch below shows a cross section end view of the tube bundles for the BACA condenser. The steam and gases enter the tube bundles at the sides and at the bottom so that the falling condensate is in opposite direction to the steam as far as it is possible to do so. The gas vapor outlet is at the top of the tube bundles. The two-pass water circuit has the cold water pass around the periphery of the tube bundle and the warm water pass through the center of the tube bundles. The gas vapor mixture leaves the tube bundles along the full length of the condenser, enters the gas vapor duct, and is then discharged to the gas removal ejector equipment. The gas cooling section of the condenser is in the cold water pass. The condensate drain trays in the residual and gas cooler areas of the condenser have means for separately draining off the condensate in these areas of possible high hydrogen sulfide concentration. Although this has no bearing on the special geothermal design requirement of keeping the hydrogen sulfide in the condensate to a minimum, the condenser has a patented method of supporting the tubes along their length without the need for conventional tube support plates.

The advantages of this design over a conventional surface condenser are:

1 The maximum gas concentration is in contact with the least condensate flow which will result in minimum contamination of hydrogen sulfide in the main body of the condensate.



END VIEW OF TUBE BUNDLES

ECOLAIRE CONDENSER

2 The condensate from this area of high gas concentration can be separately led outside the condenser for separate treatment, if necessary.

3 The first water pass (i.e., the cold pass) occurs at the periphery of the tube bundle where the gas concentration is the least (i.e., the maximum condensation rate occurs with the steam having the least gas concentration).

4 The gases do not cascade to the cold end of the condenser where, not only is the gas concentration the greatest, but where the condensate is most likely to be subcooled or be subjected to depression. Instead, venting is all the way along the length of the condenser from each compartment and directly into the gas vapor duct; therefore, only a minimum of gas comes in contact with the condensate formed and dropping from the tubes.

5 Since falling condensate is generally in the opposite direction to the steam flow, maximum stripping of condensate will occur with the hottest steam, which also has the minimum gas concentration.

Clean Room

Hydrogen sulfide gas (H_2S) has a deleterious effect on equipment that contain components made of copper, copper alloys or silver. The H_2S attacks these materials and replacement is necessary in a relatively short period of time. Electrical equipment, control and instrumentation devices usually contain the materials susceptible of H_2S attack and alternate materials are generally not available.

To minimize this problem, a clean room approach has been incorporated in the design. The plant control room, relay room and office complex are provided with filtered, temperature and humidity controlled air from the plant heating, ventilating and air conditioning equipment. The electrical switchgear room is provided with filtered and heated air from the plant heating, ventilating and air conditioning equipment. Both areas utilize replaceable inlet air filters of the activated charcoal type suitable for the removal of a mildly contaminated atmosphere containing a maximum of 10 ppm of H_2S gas.

Therefore, the control console, auxiliary control panel, fire protection supervisory panel and all equipment located in the control room are protected from the effects of the H_2S atmosphere . The STC, Annunciator, Switchyard Control and Interposing Logic systems cabinets as well as the rear of the Auxiliary Control Panel are located in relay room subject to the clean room design protection. The Generator Static Exciter Regulator, 4 kV switchgear, 480 V Plant Auxiliary Loadcenter, Generator Breaker, Vital and Auxiliary Bus Controls, and Battery Chargers are located in the switchgear room subject to the clean room design protection.

This clean room design allows the use of standard design electrical, instrumentation and control equipment with resultant cost savings. Furthermore, these plant areas are maintained at a slight positive pressure to prevent the influx of mildly contaminated atmosphere.

Use of FRP Pipe and Tanks

In the preliminary design, there was an extensive usage of stainless steel pipe for lines that were to transport H_2S bearing fluids. It goes without saying that the cost of such installation, even though considered very durable, was of high cost. Similarly, storage tanks were considered to be fabricated from carbon steel and subject to the regular maintenance associated with such application. The tank in question is the water storage tank, subject to very normal and not extreme conditions. During the evolution of the design, it was learned that the use of stainless compared to the use of fiberglass reinforced pipe would result in substantially more costly piping installations. As a rule of thumb, it was found that if a 10" pipe installation of normal complexity were to cost \$22,000 for 304 type stainless steel and \$30,000 for 316 type stainless, the fiberglass installation would result in a cost of approximately \$10,000 to \$12,000. This situation was further complicated by the fact that in order to provide for successfully welded joints, the low carbon stainless would have to be selected in order to prevent the phenomenon of inter-granular stress corrosion. This additional requirement further increased the cost of the stainless steel pipe installation.

The piping that was mainly subject to the above considerations was the in-plant piping not embedded in concrete or buried in the soil. In this design of the plant piping, the piping was segregated into the following categories:

- The underground piping for services such as:
  a. Plant, floor and equipment drains.
  b. Fire protection.
- Exposed plant piping.
- Circulating water piping.

The application of fiberglass for the exposed plant was mainly for condensate from the hotwell and the drains of the inner and after condenser of the gas ejection system as well as the gas line that transports the noncondensables to the H_2S Abatement facility.

For the in-plant and exposed fire protection pipe, carbon steel pipe was used to ensure that the fire protection piping itself would not be damaged by a fire adjacent to the fire suppression system.

Although the fiberglass piping system for the in-plant exposed pipe was carefully weighed, the final selection for this piping was based on a savings of approximately \$200,000 over the cost of the alternative application of stainless steel piping. Once the basic selection of the fiberglass material had been made, other facets associated with this pipe's particulars respective to connections, drain and vent connections, bonded connections and flange connections were subjected to close scrutiny to ensure that the possibilities of weak links in the system are properly recognized and accounted for. The various methods available from the various manufacturers for connecting pipe ends differ, and it is believed that the method of one manufacturer is superior to another. Also, the wall thickness selected by the various pipe manufacturers varies to a great extent where certain manufacturers are producing fairly thin walls that are indeed capable of taking fairly high pressures. However, the capability of these thin wall pipes to withstand crushing loads is not as good as the ability of the heavier pipe wall.

A point of interest is that because of the resilience of the fiberglass pipe, the effect of water hammer is not as pronounced in this type pipe as can be expected in a pipe of steel manufacture. It is also noteworthy that the coupled pipe joint of certain manufacturers by bonding results in amazing capabilities in hoop strength as well as strength in the longitudinal direction.

It is these considerations that were taken into account in the selection of fiberglass reinforced piping for the Baca Power Plant.

As stated hereinbefore, both the service water tank and the diesel oil storage tank were originally considered to be of carbon steel construction. However, after a cost comparison was made, the obvious benefits of filament wound fiberglass tank construction became evident. The glass tanks eliminate the need for grounding or cathodic protection and in the case of the above grade installation eliminates the need for periodic repainting.

It is believed that Baca in the use of fiberglass pipe and tanks can be considered a first for geothermal service.

Hydrogen Sulfide Considerations

The hydrogen sulfide (H_2S) content of the steam is anticipated to vary from 210 to 300 ppm. A typical steam quality analysis is shown in Table 1. The H_2S upon entering the condenser can either redissolve in the condensate or be removed as a gas through the gas ejector system.

A Stretford process is being installed to treat the gaseous H_2S emissions from the plant. Maximum H_2S partitioning (% H_2S removed as a gas/% H_2S dissolved in the condensate) in the condenser is required to make the most effective use of the Stretford system and to ensure

Table 1 Anticipated Steam Quality

pH		4.5
Suspended Solids		7 ppm
Dissolved Solids		
Silica	SiO_2	7-15 ppm
Bicarbonates	HCO_3	5 ppm
Sulfate	SO_4	2 ppm
Chloride	Cl	21 ppm
Sodium	Na	8 ppm
Potassium	K	3 ppm
Calcium, Magnesium, Barium, Boron, Fluoride	Ca, Mg, Ba, B, F	less than 1.0 ppm
Carbon Dioxide	CO_2	28,250 ppm
Hydrogen Sulfide	H_2S	205 ppm
Nitrogen	N_2	56 ppm
Hydrogen	H_2	2 ppm
Methane	CH_4	2 ppm

that condensate treatment for H_2S removal is not required. The H_2S partitioning is a function of the condenser design and steam chemistry.

The condenser is designed to assure a short residence time. This makes it less likely that equilibrium conditions between the steam, gases and condensate will be established.

Even with the establishment of condenser equilibrium conditions, the steam chemistry is favorable for most of the H_2S being removed as a gas. The expected percentage of H_2S being present as a gas as opposed to the quantity dissolved as an alkaline sulfide is a function of the condensate pH. At a pH of 4, 98% of the sulfides are present as H_2S, at a pH of 7 approximately 33%, and about 1% at a pH of 8.7.

The carbon dioxide gas concentrations and the lack of ammonia in the Baca steam would verify the reported low pH value of 4.5 and indicate that the condensate pH value will be low.

With 300 ppm in the steam, 6,659 lbs/day of H_2S will enter the system. Assuming partitioning factors of 95/5 and 99/1 the distribution of H_2S between the condensate and the Stretford process is shown in

Figure 1. Based upon the guaranteed 10 ppm effluent, the Stretford process will emit 7 lbs/day of H_2S. The cooling tower will potentially emit 666 lbs/day and 67 lbs/day with the two partitioning examples, at concentrations of respectively, 18 ppm and 4 ppm.

With a requirement to bypass the Stretford process, the gas will be sent to the cooling tower and admitted below the fan deck. The H_2S concentration in the fan stack under these conditions will be approximately 10 ppm.

If, with operation, the required partitioning is not obtained, treatment of the condensate for hydrogen sulfide removal may be required to meet environmental discharge restrictions. A number of treatment alternatives are available to remove hydrogen sulfide from the condensate.

The most reasonable alternative for retrofit from a practical and economic view is the hydrogen peroxide destruction method. This method is a chemical process operating in the liquid phase with iron used as a catalyst at approximately 1 ppm. Equipment required for the process includes hydrogen peroxide tanks and pumps, ferrous sulfate tanks and pumps, and possibly condensate filters. Hydrogen sulfide effluent concentrations of less than 0.1 ppm can be obtained.

The condenser design permits removal of condensate from high gas concentration condenser areas for separate treatment outside the condenser, if required.

Effects of Altitude on Electrical System Components

Types of power plant equipment whose ratings are affected by altitude include the following:

- Power Transformers.
- Switchgear and Metal Enclosed Bus.
- Induction Motors.
- Engine-Driven Generators.

The Baca power plant comprises equipment in all of the above categories, which will be installed at the site elevation of 8,750 feet above mean sea level, and which will be affected in varying degrees by the plant altitude.

The effects of altitude upon power equipment are due primarily to two causes:

- The reduced density of air at higher elevations, which reduces its ability to remove heat from energized apparatus, and decreases the mass of oxygen per unit volume of air available for combustion.
- The reduced dielectric strength of air at higher elevations, which reduces its effectiveness when used as an insulating medium.

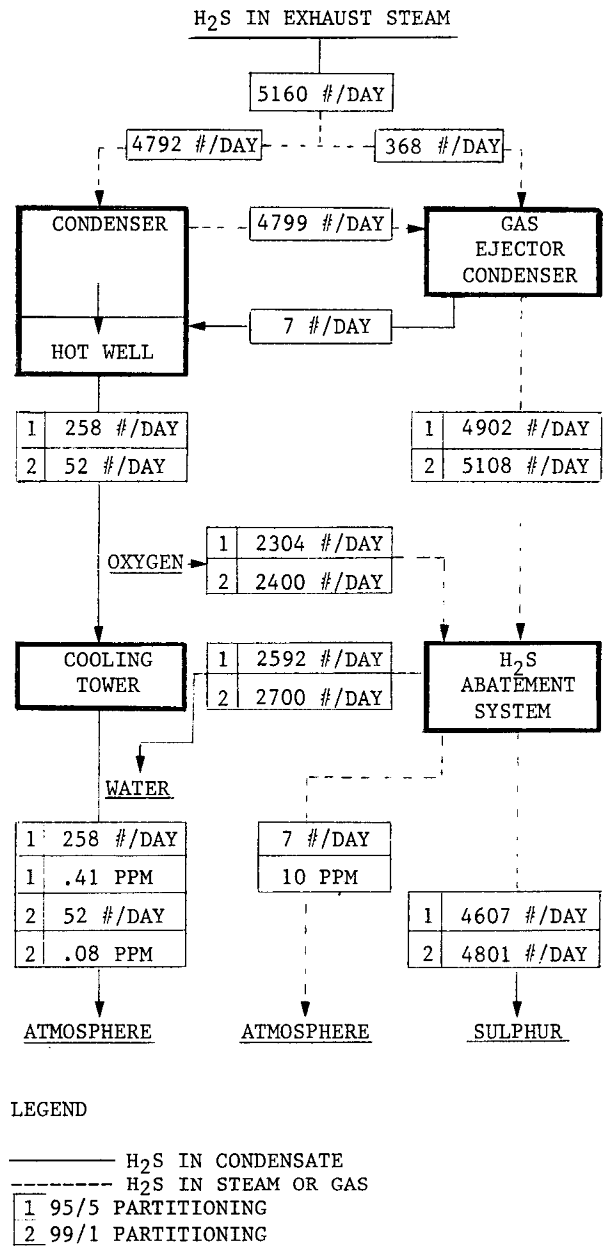


Fig. 1 H_2S FLOW DIAGRAM

The effects of these two properties of high-altitude air are summarized below for each type of equipment listed above.

Power Transformers

- Main Step-up Transformer - No derating necessary.
- Unit Auxiliary Transformer - No derating necessary.
- Loadcenter Transformers - No derating necessary.

- Dry Type Lighting Transformers - Derate 5 percent.
- Transformer HV Bushings - Extra creepage required.

Switchgear

- Medium Voltage Switchgear
  - Derate current to 97 percent
  - Derate interrupting capability
  - Use surge arresters for reduced BIL
- Non-Segregated Phase Bus
  - Derate current to 97 percent.
- Low-Voltage Switchgear
  - Derate current to 99 percent.
  - No voltage derating necessary
  - No interrupting capability derating necessary

Induction Motors

- All Motors
  - Derate in accordance with NEMA MG-1

Engine-Driven Generators

- Emergency Generator
  - Derate for altitude in accordance with DEMA

Advantage of the Flash Design

The main advantage of a flash design, geothermal plant, whether flashing down hole or at the surface, is the yield of water in the condenser, which is used for cooling tower makeup when using evaporative cooling. This advantage is to be predicated by the quality of the condensate yielded and if of acceptable quality the yielded condensate can be used as makeup.

For the purpose of evaporative cooling, the binary cycle and any other conventional plants would be reliant on the availability of water that needs to be imported to the plant.

The Baca Geothermal Plant is an exception in this regard as its condensate is used in the cooling tower for makeup; this is of particular advantage in that the Baca Geothermal Plant is located in an area where external water supplies are scarce and costly.

Only the plant service water needs to be imported and its consumption has been limited to the purposes of drinking, domestic and maintenance use.

In this regard, the plant uniquely fits in with what the environment can offer.

The water or brine in the aquifer would be of no use to anyone otherwise, except for the production of electric power.

If the water were available in the quantities required, the quantity and cost for evaporative cooling would be approximately 2,234 acre feet and $1,750,000 annually, respectively.

The allotment of potable and service water at the Baca Plant is 3 acre feet per year.

Turbine Blow-off Piping

In an effort to safely route steam discharges from the turbine casing shear diaphragms to outside the building, the Baca job is a first in displaying this feature. This additional safety feature was introduced to compensate for the possible failure of closing the turbine control and stop valves in the event of a load rejection accompanied by a noncondensing condition.

This design approach has been practiced in Europe in certain power stations, but is commonly not used in the United States.

Owing to the possible adverse effects that impurities in the steam have on the operation of the emergency stop and control valves it was reasoned to be a good investment to include this blow-off piping in the design to eliminate the possible hazards associated with the turbine blow-off in the power building.

The hazards that can be foreseen are two-fold:

1 The first concern is about the safety of personnel inside the power plant.

2 The second concern is the damage that H_2S bearing steam can impose on power plant electrical equipment.

OTHER POINTS OF INTEREST

Costs

The Detail Design for the Baca Project has been underway for approximately 17 months and the estimated project costs are running fairly close to budget. There have been influences of design growth causing the plant costs to increase; however, there have also been factors that caused the costs to decrease.

At the present time, the design is approximately 75% complete and it is believed that cost variations resulting from variations in design are going to be minimal the rest of the way.

Not accounted for in the above, is an increase in project costs resulting from a delay in the acquisition of the Environmental Impact Statement.

In relation to the total project costs, this increase has been kept to a minimal.

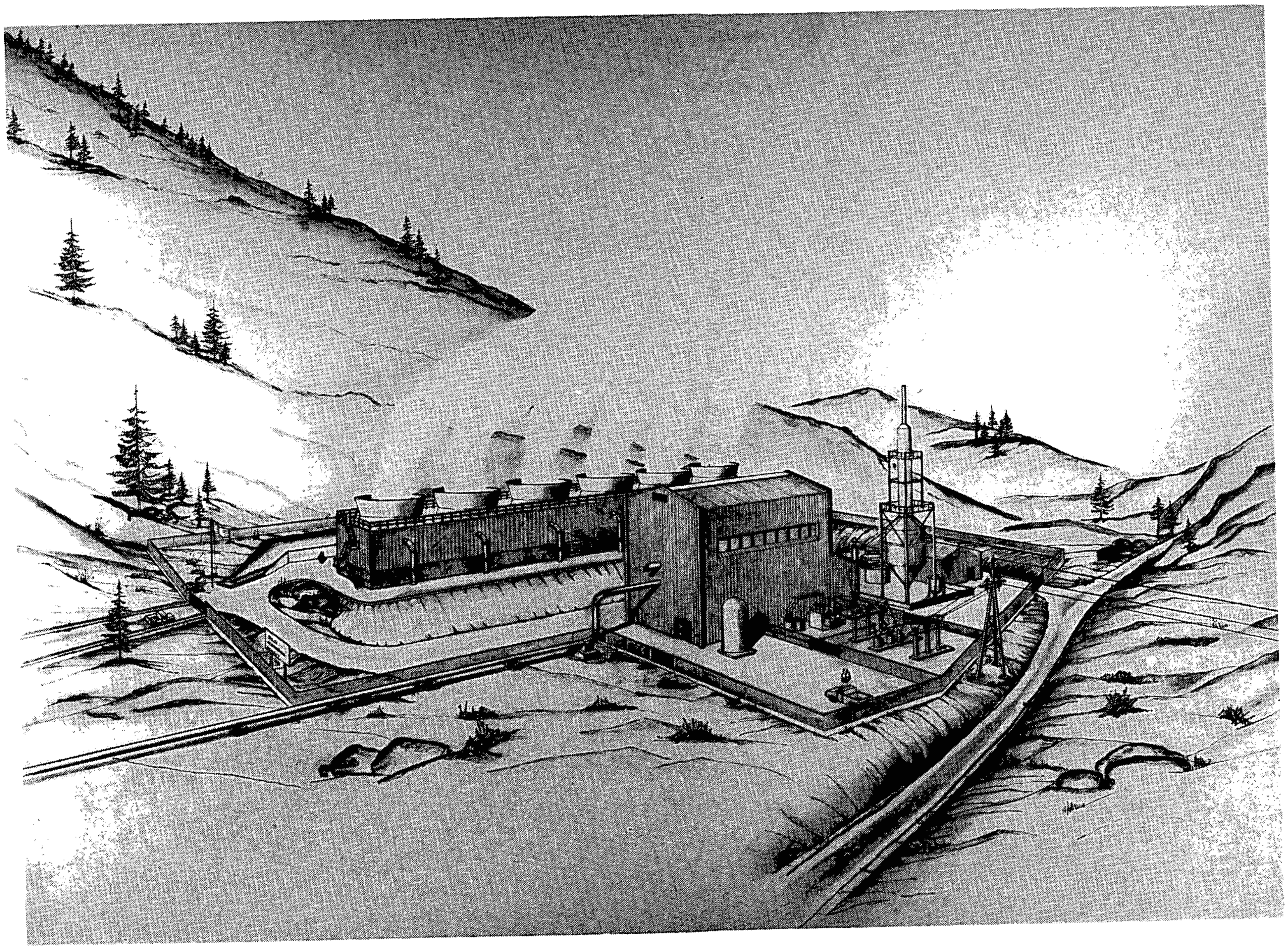
At the present time, it is estimated that the cost of the power plant not including the switchyard will be approximately $650.00 per installed kW.

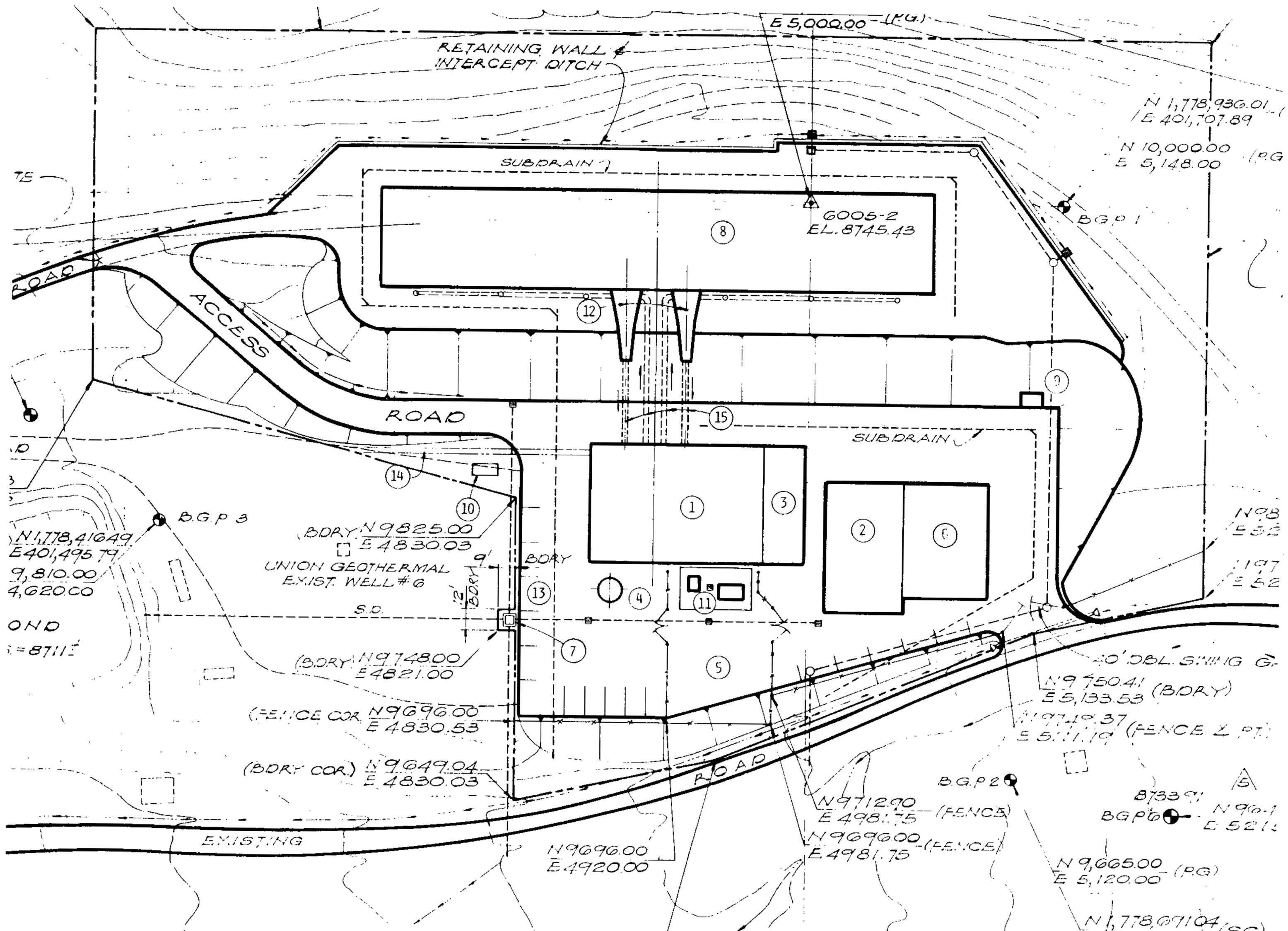
The above unit cost does not include cost of real estate and owner's costs.

Schedule

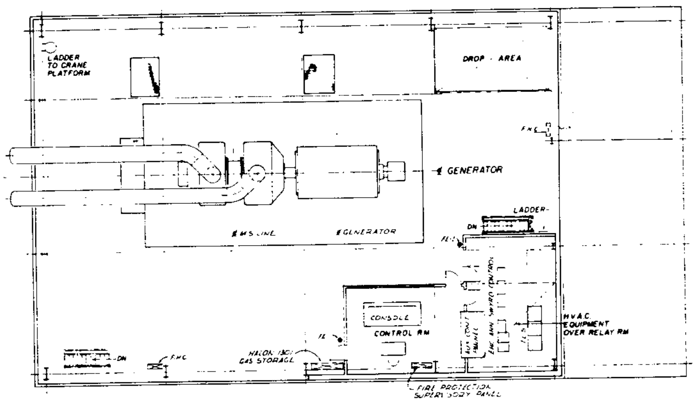
From the notice to proceed to commercial operation, the duration for design and construction was scheduled to be 37 months allowing approximately 22 months for construction. This construction span is now reduced owing to the delay of the Environmental Impact Statement; however, it is believed that the plant can be started up as scheduled.

The climate prevailing at the approximately 9,000 foot elevation has a profound effect on cost effective construction and it was found that the cost was very sensitive as to when actual construction was started. If construction is delayed past a certain point in time of a calendar year, the climatic conditions begin to exert their influence and the construction costs rise dramatically resulting from the increased cost of accelerated construction to avoid the adverse weather conditions of winter.

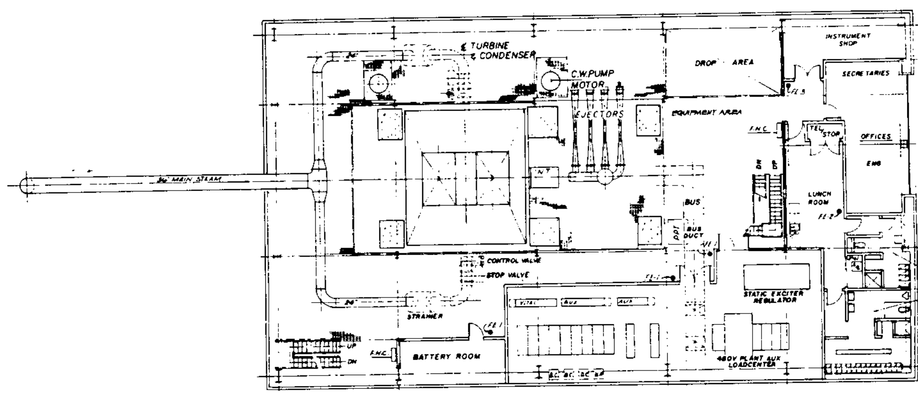



RETAINING WALL ¢
INTERCEPT DITCH
E 5,000.00
SUBDRAIN
G005-2
EL. 8745.43
N 10,000.00
E 5,148.00
B.G.P 1
ACCESS
ROAD
SUBDRAIN
B.G.P 3
UNION GEOTHERMAL
EXIST. WELL #6
S.D.
(FENCE COR.) N9696.00
E 4830.53
(BDRY COR.) N9649.04
E 4830.03
EXISTING
40' DBL. SWING GATE
N9750.41
E 5,133.53 (BDRY)
N9712.90
E4981.75 (FENCE)
N9696.00
E4981.75 (FENCE)
N9696.00
E4920.00
N 9,665.00
E 5,120.00 (P.G.)
B.G.P 2

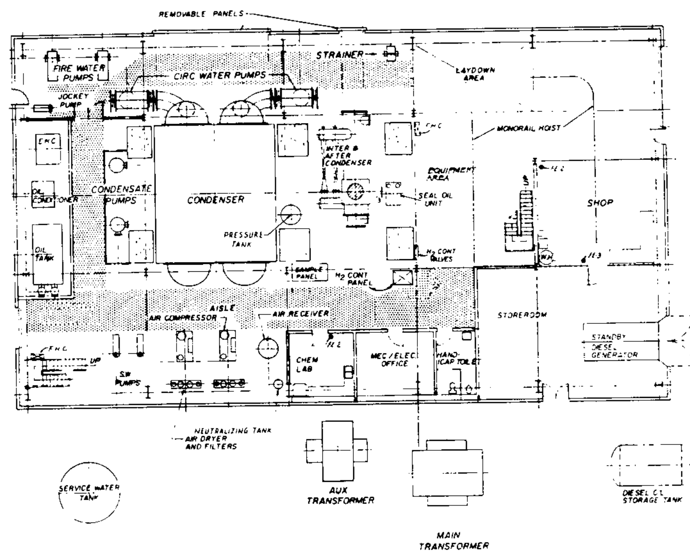
SITE PLAN



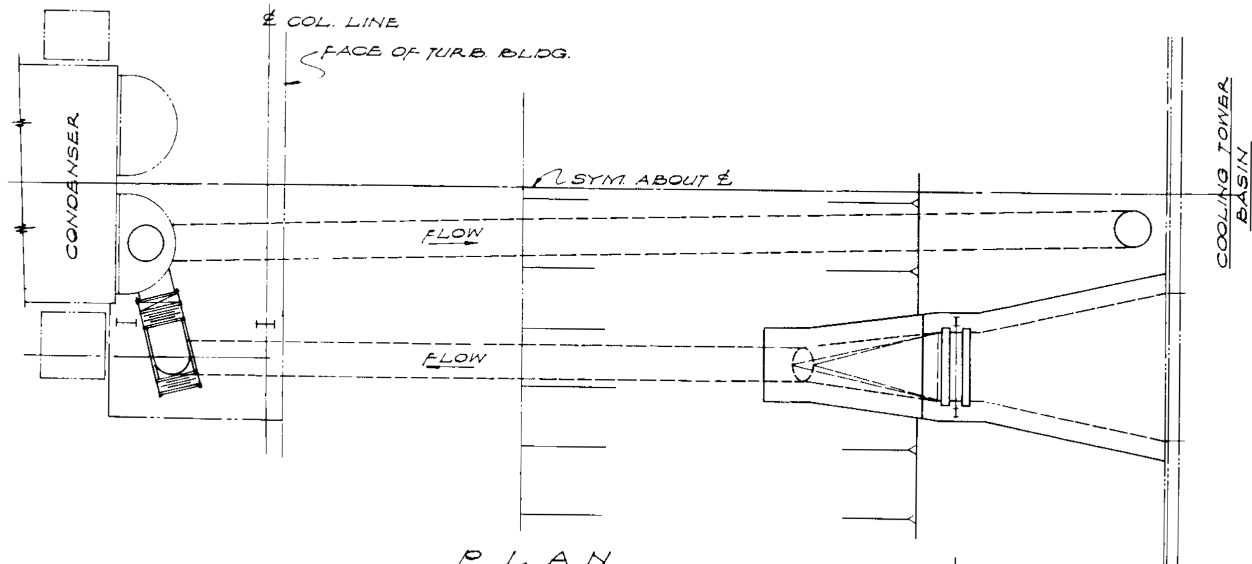
OPERATING LEVEL EL 130'-0"



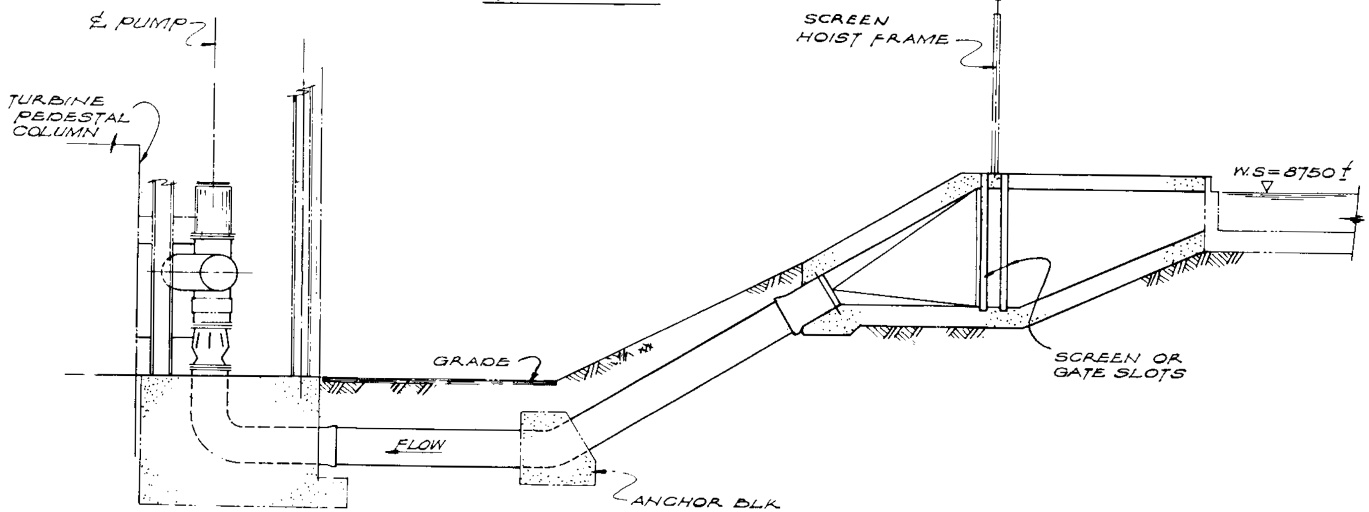
MEZZANINE LEVEL EL 115'-0"



POWER BUILDING
GENERAL ARRANGEMENT



PLAN



SECTION

CIRCULATING WATER SYSTEM

THE BACA DATA DISSEMINATION PROGRAM

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Introduction The goal of the federal government's coordinated program of research and development in geothermal energy is to stimulate the economic, reliable, operationally safe, and environmentally and socially acceptable commercial development of this energy resource. This commercialization plan is based on the premise that developers, utilities, and the financial community will not make large-scale commitments to unfamiliar technology until confidence is gained from the commercial-scale demonstration of this technology. The primary objective of the Baca Geothermal Demonstration Power Plant Project, therefore, is to provide that confidence through a first-of-a-kind commercial-scale fifty-megawatt demonstration of the production of electric power from a liquid-dominated hydrothermal resource in the United States.

The Baca Geothermal Demonstration Power Plant Project is organized and largely cost-shared under a cooperative agreement which casts the U. S. Department of Energy (DOE), Public Service Company of New Mexico (PNM), and Union Geothermal Company of New Mexico (Union) into the roles of partners in a joint undertaking. In the absence of government participation, all technical and financial data generated during plant design, construction and operation would remain proprietary within the respective industrial firms. Under the Baca Cooperative Agreement, however, all such data are to be organized and disseminated to the public at the sole expense of DOE. The Baca data dissemination task is being performed by WESTEC Services, Inc., under contract to PNM and Union.

Project Data Sources The Project will be an integrated commercial-scale geothermal electric power generating plant which utilizes a liquid-dominated resource. As such it will include the geothermal field system, fluid production equipment, fluid transmission system, steam separator system, electric generating plant, H_2S abatement system, geothermal fluid treatment and spent fluid disposal facilities, and a tie-in to the electric utility transmission network.

All technical data from the Project and most routine interpretation of technical data will be available for dissemination without restriction. However, any computer programs, proprietary interpretive methods, correlations derived from operations outside the Project, and information regarding contractual relationships will generally not be made available for dissemination.

The following categories of data are anticipated to be made available from this Project:

- Financial
  - Capital Costs
  - Resource Development Costs
  - Owners' Costs
  - Operations and Maintenance Costs
  - Fuel Costs
  - Total Generation Costs
- Legal/Licensing/Permitting
  - A Case History of the Regulatory Process Required for the Baca Project
- Facilities Engineering and Operations
  - Engineering and Economic Evaluations
  - Engineering Design Documents
  - Engineering Planning Evaluations
  - Operations and Maintenance Reports
  - Comparisons of Design vs. Actual Performance
  - Operational Characteristics Evaluations
  - Injection Data Evaluations
  - Metallurgical and Chemical Analyses of Materials Problems
- Environmental Monitoring
  - Ecology and Water Quality Monitoring Including Characterization of the Botanical, Zoological, and Hydrological Ecology of the Project Region
  - Meteorology and Air Quality Monitoring, Resulting in Implementation of a Network of Monitoring Stations for Air Quality and Site Meteorology
- Exploration Data
  - Vertical and Horizontal Ground Movement Evaluations

Exploration Data (Continued)
- Gravity and Tilt Measurement Evaluations
- Near-Surface Temperature Measurement Evaluations
- Electrical Resistivity Studies
- Telluric Studies
- Formation Rock Properties

- Resource Development/Production (Subsurface) Data
  - Pressure Transient Analyses
  - Interference Test Analyses
  - Interpretation of Tracer Studies
  - Injectivity of the Reservoir
  - Reservoir Performance Predictions
  - Integrated Reservoir Case History

Information User Groups Very simply, the purpose of the Baca Data Dissemination Program is to link the Project data sources to a potentially broad spectrum of information users and to ultimately provide these information users with the data they need to gain the confidence in this unfamiliar technology required to stimulate further commercial development of this energy resource.

Major sources of project data will include the power plant, the production system, and all associated geological, geophysical, subsurface, environmental, legal and financial data as outlined in the preceding section. Potential users of these data include industrial organizations such as utilities, resource developers, architect-engineering firms, and equipment manufacturers; financial institutions rank high as desired potential data users. Additional anticipated data users include research and academic groups, technical support and field support service organizations, resource conservation and regulatory agencies, and special interest groups. Each of these generic groups will have specific information requirements necessary to influence decisions affecting their future involvement in geothermal projects. One immediate goal of the Baca Data Dissemination Program is to identify and plan for addressing these specific information user requirements.

Information Dissemination Planning The primary objective of the Baca Data Dissemination Program is to provide the generic information user groups, identified in the previous section, with quantitative bases for assessing the technological and economic risks and benefits associated with geothermal development. To meet this objective, an Information Dissemination Plan has been in preparation which will clearly define exactly who each of the user groups are and what information content and form is acceptable to each. To aid in this planning effort, an industrial and financial community survey has been formulated to identify the specific information needs of each user group addressed.

Once the findings of the industrial and financial community survey have been evaluated, a basic plan for communicating with each of the several user groups will be formulated. The conceptual approach for information communication calls for a series of modular summary report units to be formulated (including both financial and technical report formats), which will be combined into assemblies appropriate to each user group, and disseminated. In some instances, more detailed information will be available to the information user, upon request, in the form of Topical Reports and Quarterly Technical Progress Reports. In addition, an annual Baca Project Symposium will be conducted in Albuquerque, New Mexico, to stimulate better communication and interaction between the information users and the project data analysts. The first such symposium is tentatively scheduled for the late-1980/early-1981 time frame.

Present Status WESTEC Services, Inc. has mobilized a project team with extensive geothermal experience to implement the Baca Data Dissemination Program. Systems, Science and Software is providing the evaluation of geological, geophysical, and subsurface data, while Coopers and Lybrand is providing the project financial analyses. WESTEC Services is providing the overall program management as well as the evaluation of power plant, production system, environmental, legal and institutional data.

A total of over sixty reports or studies relating to the Baca Project have already been prepared by PNM and Union. Executive Summaries of these reports are presently being prepared and will be available to industry by contacting WESTEC Services' Albuquerque Office. The Information Dissemination Plan is expected to be completed in July 1980 along with the first Baca Project Quarterly Technical Progress Report. The first Modular Summary Reports can be expected to appear in early-1981.

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SESSION 3

EPRI PROJECT REPORTS

BINARY CYCLE GEOTHERMAL DEMONSTRATION POWER PLANT

NEW DEVELOPMENTS

RP1900-1

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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.

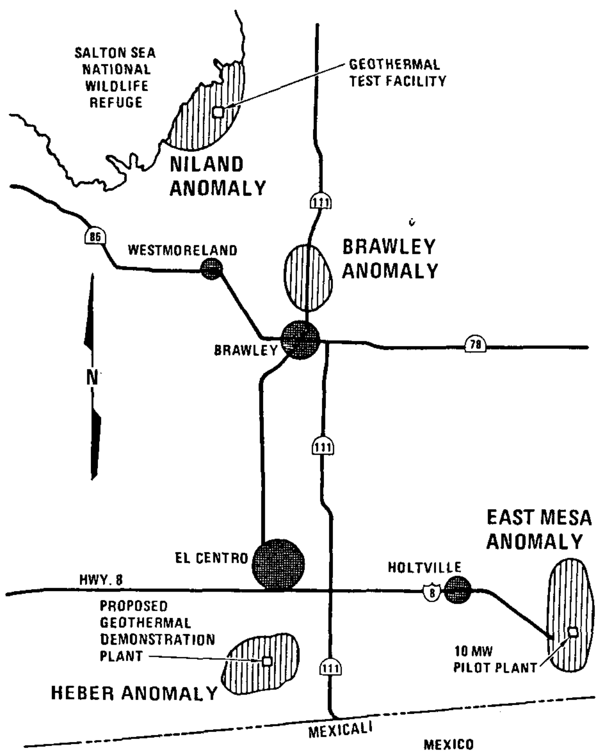

FIGURE 1
IMPERIAL VALLEY GEOTHERMAL RESERVOIRS LOCATION MAP

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 scale 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 sources of power to San Diego, and support of Magma Electric's 10 MW East Mesa Geothermal Power Plant. Current planned SDG&E efforts emphasize commercial scale planning, risk reduction, and development.

EPRI-sponsored work leading to this project has been heavily relied upon. Field testing, environmental baseline, and feasiblity 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) of 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 MWe 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 results of the feasibility study, and work has continued in reservoir analysis and plant design since that time.

SDG&E conducted heat exchanger tests at the Heber reservoir for EPRI beginning in 1974, which showed minimal problems in handling the Heber brine. In 1975, SDG&E's interest was further heightened when Chevron Resources Company, Inc., the major geothermal leaseholder at Heber, approached SDG&E with an offer to sell heat from the reservoir for use in a geothermal power plant. 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 for gathering baseline environmental information at the reservoir to help assess the future 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. Because of the encouraging results of the EPRI feasibility study, field tests, and environmental studies, SDG&E decided in mid-1976 to begin assembling a project team to pursue Federal government support for the construction and operation of a commercial-scale demonstration plant at the Heber reservoir. From the outset, SDG&E recognized that substantial external funding support would be needed to reduce the risks of undertaking this first-of-a-kind demonstration project to an acceptable level. Since the benefits would be representative and applicable to a broad section of the industry, Federal assistance appeared to be well justified. Participation in the construction and operation of the Heber Binary Project was also solicited from 26 western utilities and several California State governmental agencies.

Following the request for Federal financial assistance, it was decided that SDG&E would act as the project manager and the principal owner of the power plant. Other utilities interested in participating as plant owners included the Imperial Irrigation District, Los Angeles Department of Water and Power, and Southern California Edison Company. EPRI was to be the major contributor. Other contributors to the project were to be Nevada Power Company, Portland General Electric, Republic Geothermal, Inc., Geothermal Resources International, Inc., California Department of Water Resources, and the California Energy Commission. Although the financial risk was spread among a number of owners and contributors, it was clear that major Federal support would still be required.

In early 1977, in order to present a comprehensive proposal to the Federal government, SDG&E began negotiations with the participants and with the Chevron Resources Company, which was to supply the geothermal energy from the reservoir.

At about that time, DOE requested an Expression of Interest (EOI) from organizations desiring to participate in a demonstration project for the utilization of geothermal energy for electric power generation. SDG&E and other participants submitted an EOI in June 1977, to obtain Federal funding. It was assumed that because the proposed Heber plant had unique merits, proven need, and was well enough defined to meet all of the qualifying criteria, Federal funding was highly likely. Therefore, planning proceeded on the assumption that DOE would quickly become a participant in the Heber project. However, DOE requested detailed design responses to a Program Opportunity Notice (PON) for a geothermal demonstration project with an unspecified process utilizing an unspecified geothermal fluid at unspecified conditions.

SDG&E and the other participants then submitted a response to the PON in January 1978. Preliminary design and engineering activities were suspended until DOE made its announcement of which of the candidate projects would receive Federal cost sharing.

It was learned in July 1978 that DOE had elected to co-fund a high resource temperature, single stage, flash power plant project and that Federal funding would not be available to develop the higher risk, but potentially more widely applicable, commercial-size binary cycle demonstration plant project. Although additional funding was sought from various sources (including the existing participants, EPRI, and other interested parties), sufficient funding was not available and the original project was terminated at the end of 1978.

<u>Recent Events</u> 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 Cong., 1st Sess., 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 was greatly interested in these developments because of its extensive earlier involvement in proposing a binary cycle demonstration plant at the Heber reservoir. SDG&E consulted with other utilities and interested parties and decided to again solicit government funding for a binary plant at Heber.

SDG&E obtained expressions of interest from other utilities to participate in a new Heber binary cycle demonstration plant. The Imperial Irrigation District, Southern California Edison Company, and California Department of Water Resources all expressed an interest in sharing in the power output, as well as 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-sized nominal 50 MW binary cycle demonstration plant. This proposal was based upon the previous project, but was updated to current information on the site, participants, scope, regulatory approvals, cost, and schedule.

In conjunction with this proposal, SDG&E requested and was granted special rate treatment for SDG&E costs associated with this project 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 of negotiation for a Cooperative Agreement. Negotiations with DOE were initiated on March 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.

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.

Such a demonstration plant would 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 is an advanced concept that has the major advantage of being capable of converting a greater amount of geothermal heat from moderate temperature brines into new 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 approximately 40% less geothermal fluid per net kilowatt generated than the dual flash cycle.

DESCRIPTION	BINARY CYCLE BOL	BINARY CYCLE EOL	DUAL FLASH CYCLE BOL	DUAL FLASH CYCLE 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 Temperature Degrees F	360	338	293	293
Brine Return Temperature 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 costs which will be significantly reduced for a given size binary plant. In addition, if current research and development activities are successful (i.e., direct contact heat exchangers and down hole turbine driven pumps), this could further reduce costs. Binary cycle technology will also increase the total potential output of each geothermal resource.

However, to realize all of these potential benefits, binary cycle technology must be proven on a commercial size. 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 proven 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 160°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 psia 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 resulting from 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 power plant is an outdoor-type station having a net power output of 45 MW. The outdoor concept provides for the turbine generator and other major equipment to be installed outside so as 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.

The long history of exploration and development of the Heber Reservoir has resulted in one of the most well understood hydrothermal resources in the United States. After early exploration and well testing by several resource developers, NARCO, Magma Energy Inc., and Chevron Resources Company agreed to join in a test program to evaluate the geothermal resources in the Heber area and to determine the potential for commercial development. The program was undertaken in 1973 to establish the size, and other characteristics, of the Heber geothermal reservoir and to determine the reliability and operating characteristics of well pumps and other equipment necessary for production and injection of the geothermal fluid.

The reservoir evaluation program continued in 1974, and two additional wells were drilled on a cost-sharing basis by Chevron, Magma, and NARCO. In 1976, Union Geothermal, which also holds leases in the Heber reservoir, commenced a drilling program on leases adjacent to those of Chevron, Magma, and NARCO. Data made available by Union's drilling were exchanged for drilling data collected by Chevron, Magma, and NARCO. In 1977, additional wells drilled by Chevron and Union provided a more detailed understanding of the geothermal reservoir. The subsequent full reservoir analyses indicated 500 MW of power production potential from the Heber reservoir.

After NARCO acquired Magma's lease interests at Heber, negotiations involving Union Oil, Chevron Resources Company, and NARCO began in 1977 for the unitization of the Heber geothermal field. These negotiations culminated in 1978 with the signing of the Heber Unit Agreement, with NARCO controlling 9.2%, Chevron 61.6%, and Union 29.2%. Chevron, acting as operator for the unit, filed with Imperial County for G-overlay zoning for the geothermal reservoir and conditional use permits for the development and operation of the geothermal field. The rezoning and the conditional use permits were granted by the County in mid-1978.

The Heber Binary Project is expected to be in service in the early 1980's with production of geothermal heat for the generation of power. SDG&E is negotiating with Chevron and Union for purchase of geothermal heat. In addition, Southern California Edison has signed a contract with Chevron for the supply of geothermal heat to a steam flash plant on the Heber reservoir by 1982.

Figure 4 shows some of the wells and includes the reservoir temperature profile to a depth of 6000 feet. Extensive well flow and injection testing and analysis gives high confidence that this resource will reliably support the project.

The master schedule is shown in Figure 5. A strong DOE funded data acquisition and dissemination effort is expected to continue throughout most of the project life. Plant activities are to be closely integrated with wells and field efforts.

Current Status Current project activities as of this writing consist predominantly of contract negotiations, associated contract support efforts, and detailed project planning and criteria definition. A Cooperative Agreement is being negotiated with the Department of Energy. Drafts of key sections have been circulated and key issues identified.

EPRI Cooperative Agreement and participation agreements are also being negotiated. Drafts are being prepared or revised. Key issues have also been identified.

Remaining subcontract negotiations are in process. A contract with IID to supply water is in place, with a backup water supply approved by the State of California. Heat sales and engineering contracts are being negotiated.

Activities supporting these negotiations are also in process. DOE-related activities requiring support include pre-award audits, environmental assessments, and cooling water review by the Water Resources Council. SDG&E and DOE activities include obtaining a letter of credit, review and approval of purchasing procedures, and support of DOE's data collection dissemination scope of work.

Detailed project planning, organization, and criteria definition are in process. SDG&E's project organization was internally approved and a chart of accounts is in place. Review and update of the seismic design criteria is being accomplished, along with soil tests at the site. Plans for a reliability engineering program and data collection/dissemination interface and support are being formulated. Project procedures are being updated and revised.

Project Philosophy Demonstrating the commercial scale reliability and economics of the binary cycle process is the primary consideration for this 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. The design will accommodate the anticipated range of brine temperatures and flow rates, rather than requiring retrofit modifications.

Process and equipment will utilize proven, off-the-shelf hardware 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 planned. 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.

Summary SDG&E expects to begin design and construction of a binary cycle demonstration plant in the near future. 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.

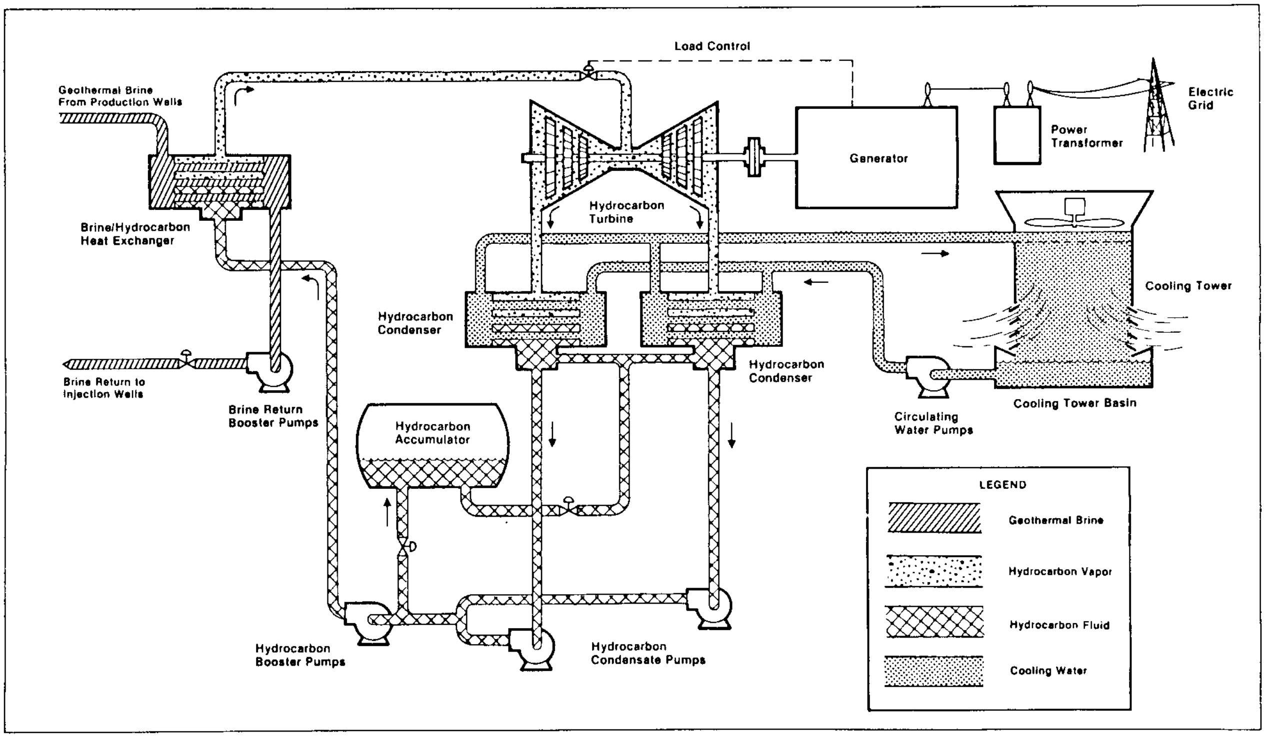

FIGURE 2 - POWER CYCLE

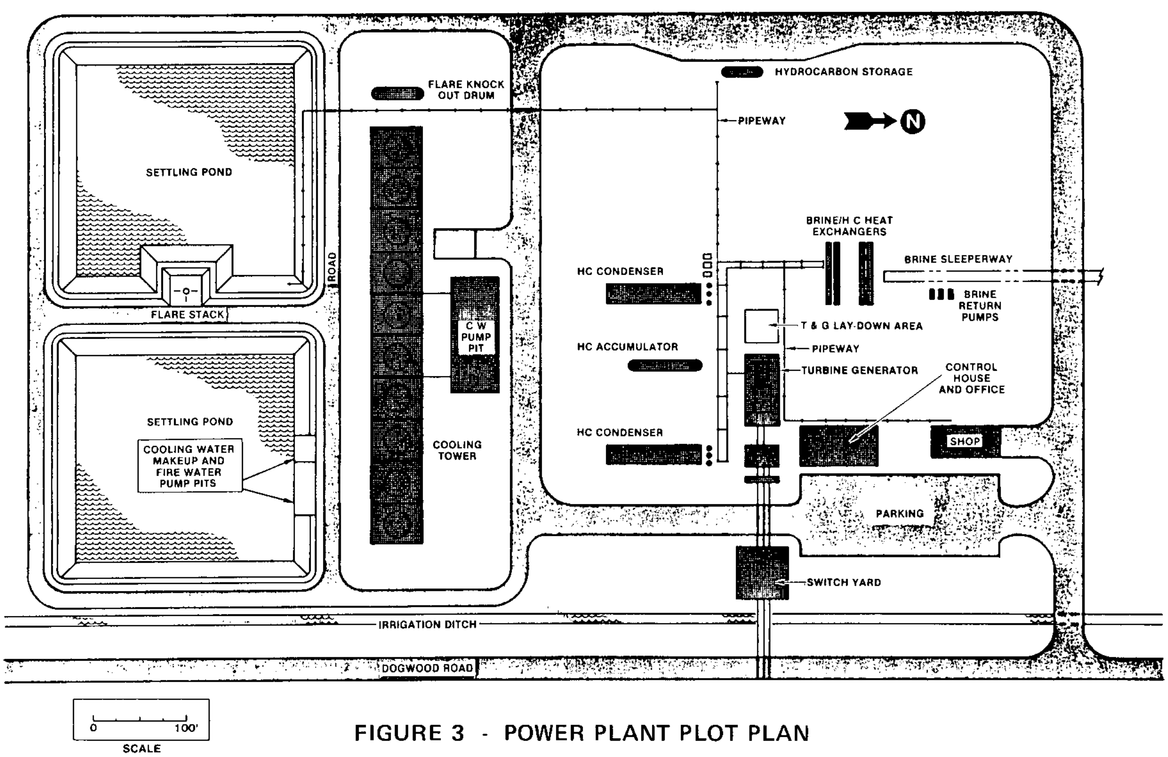

FIGURE 3 - POWER PLANT PLOT PLAN

Arrows indicate locations of exploratory wells.

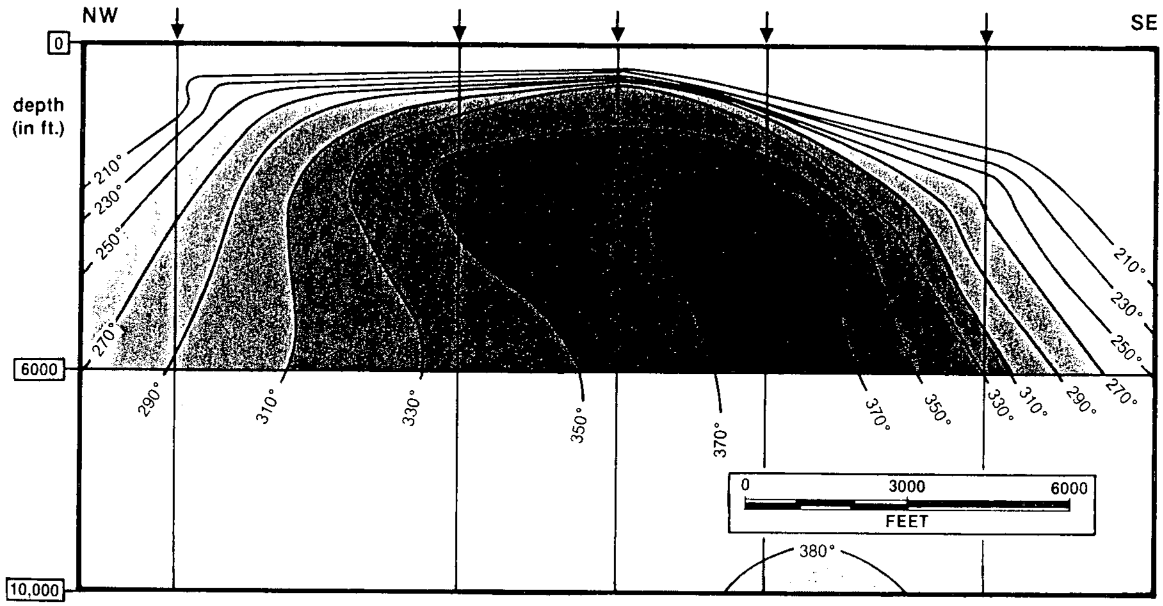

FIGURE 4 - NW-SE TEMPERATURE CROSS-SECTION OF THE UNIT AREA

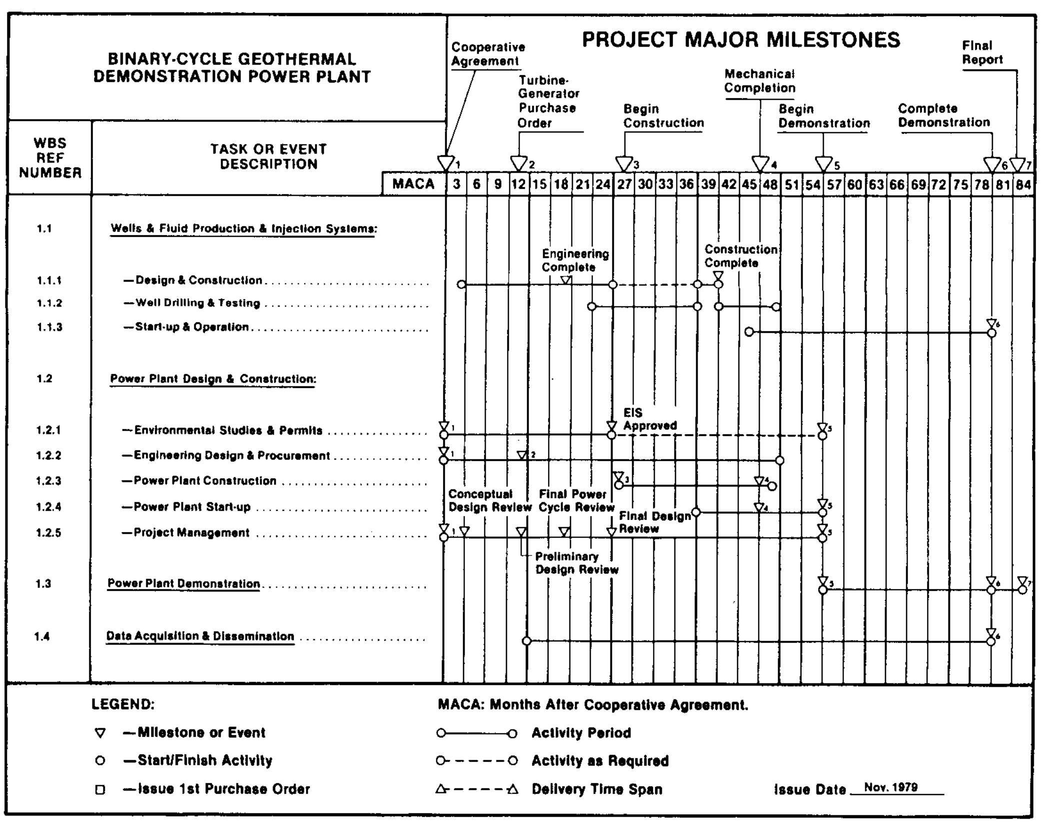

FIGURE 5 - MASTER SCHEDULE

POWER SYSTEM EQUIPMENT MODULE TEST PROJECT

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Introduction The technology of electric power generation when applying the binary process to hydrothermal resources had not yet been demonstrated in the United States. Accordingly, on November 10, 1977, the Electric Power Research Institute and the Department of Energy, acting through the Lawrence Berkeley Laboratory, agreed to cofund the Power System Equipment Module Test Project.

The Power System Equipment Module Test Project consisted of a field test program to accomplish the objectives listed below while heating hydrocarbon fluids to above their critical points, expanding these fluids, and subsequently, condensing them below their critical points:

- Verify the performance of state-of-the-art heat exchangers in geothermal service;
- Verify the heat exchangers' performance heating either selected pure light hydrocarbons or selected mixtures of light hydrocarbons in the vicinity of their respective critical pressures and temperatures;
- Establish overall heat transfer coefficients that might be used for design of commercial-size geothermal power plants using the same geothermal brine and light hydrocarbon working fluids;
- Perform and investigate the above under representative fluid operating conditions during which the production wells would be pumped.

The project was accomplished by diverting approximately 200 gpm of the flow from one of Magma Power Company's geothermal wells in the East Mesa Geothermal Field. After the heat was removed from the geothermal brine flow, the cooled flow was returned to Magma Power Company and recombined with the main brine stream for disposal by reinjection.

Approximately five thermal megawatts was transferred from geothermal brine to hydrocarbon working fluids in a closed system. This heat was removed from the working fluids in a condenser and subsequently rejected to the environment by a wet cooling tower. The thermodynamic performance of both the working fluids and the system components was measured during the test program to achieve the project's objectives.

The objectives for this field test program are considered on two levels, broad (or overall) objectives and specific data objectives.

Broad Objectives

1. Determine the overall (or average) heat transfer parameters for one-pass, countercurrent flow brine-secondary working fluid heat exchangers typical of those proposed for a commercial-size power plant.
2. Observe the behavior of secondary fluids in processes similar to those planned for a commercial-size power plant.
3. Confirm fouling factors for the design of brine/secondary fluid heat exchangers appropriate to a commercial-size plant.
4. Establish heat exchanger tube-side cleaning procedures and the effects of procedures upon exchanger performance.

Specific Objectives

1. Measure fluid temperatures and pressures of the brine and the secondary fluids along the length of the heat exchange process. The secondary fluids include water, isobutane, isobutane/isopentane.
2. Perform heat and mass balances on the heat exchanger and condenser for each fluid test.
3. Determine overall heat transfer coefficients with:
   - Brine on the tube-side and water on the shell-side
   - Hydrocarbon on the shell-side and brine on the tube-side.
   - The increasing fouling factor with time of the brine (tube-side) with hydrocarbon fluids on the shell-side.
4. Analyze pressure drop data to determine shell-side mean friction factors.
5. Compare experimental results with simulations of heat transfer, pressure drop, and fluid properties (for each run of shell-side fluids).
6. Determine brine-side scale compositions, corrosion rates, and corrosion products and compare with those obtained in prior tube and annulus experiments.

7. Compare experimental heat transfer data with results predicted using well-known heat transfer correlations and examine their validity (at the local Reynolds number, Prandtl number, Mean Nusselt number data points corresponding to the heat exchanger sections used).

8. Study scale removal operations and investigate possible sensitization of brine side (tube-side) surfaces to repeated scale removal operations by measuring scaling rates, corrosion rates, scale composition, and corrosion products.

9. Confirm test loop design parameters and thus provide a benchmark for comparison with design methods.

Operations and Data Analysis Summary Test operations and the analysis of the recorded data began on October 31, 1979. All test operations were terminated January 16, 1980. Testing in accordance with the Test Plan governing direction of the Power System Equipment Module Test Project was prematurely shortened on December 5, 1979 due to loss of hydrocarbon fluid through three pinhole leaks in a heat exchanger tube-to-tube sheet weld. Subsequent test operations occurring in January 1980 were based on knowledge gained during the prior test work and recognized that several of the goals and specific project objectives could not be met with the character of the geothermal brine used for testing purposes.

- The geothermal brine was found to be generally corrosive. No brine side fouling occurred. Hence the ability to monitor this fouling as a function of time and to investigate the effects of chemical cleaning of brine exposed surfaces did not exist.

- All test operations, both with subcritical and supercritical heat exchanger hydrocarbon fluid conditions, were found to be extremely stable and repeatable. A lack of exchanger-by-exchanger pressure measurement capability curtailed the ability to further investigate the behavior of the hydrocarbon working fluid near its critical point. The stable operation, coupled by this lack of instrumentation, precluded the need to vary heat exchanger test conditions over small increments. Accordingly, the detailed performance measurements as directed by the test plan were unnecessary.

- The extreme fouling apparent in the condenser, coupled with the approximately four times excess area in the condenser all but eliminated the ability to obtain detailed condenser performance data.

Accordingly, the test operations during January 1980 were redirected to obtaining operating data with hydrocarbon fluid mixtures. Even though the reload isobutane obtained from a commercial supplier in December 1979 had been contaminated with propane, two series of tests were run. The first series of hydrocarbon mixture tests included approximately 10 mole percent isopentane, the second approximately 20 mole percent isopentane.

All test operations were stable and easily controllable. Once a sufficient inventory of hydrocarbon fluid was established in the hydrocarbon fluid loop, predetermined process conditions could be set manually and repeatably. Little need existed to rely on the automatic control capability designed into the test systems. Excessive manufacturing slag and machined chips were found in the heat exchangers causing uneven operation of the hydrocarbon throttle valve. Also, excessive temperatures in the cooling water caused a rapid buildup of scale on the cooling surfaces and on cooling water control valve trim. These latter two problems were solved in the field by primary reliance on manual operation of the controllers. This manual operation enhanced the operational stability of the Power System Equipment Module Test.

In all, 281 data scans were completed before loss of the hydrocarbon inventory caused premature termination of the hydrocarbon heat exchanger isobutane performance tests. An additional 44 data scans were completed in January 1980 with various fluid mixtures. These included 19 with approximately 5 mole percent propane in isobutane, 20 with about 10 mole percent isopentane in the prior fluid, and 5 with about 20 mole percent isopentane. Not all data scans were used as input to the Data Processing System. A set of 119 data scans constitute the set of coherent data available from the Power System Equipment Module Test. Their analysis is statistically meaningful. Table 1-1 below summarizes the test operations of and the data analysis available from the Power System Equipment Module Test.

Table 1-1

OPERATIONS AND DATA ANALYSIS SUMMARY

Working Fluid	Test time (hrs)	As % of Total Time	Number of data scans	Number of qualified data scans
>98% isobutane	582	67	282	119
4.8% propane 95.2% isobutane	24	13	19	note 1
4.3% propane 85.8% isobutane 9.9% isopentane	25	100	20	note 1
3.8% propane 76.5% isobutane 19.7% isopentane	5	100	5	3

Note 1: Physical properties not available for performance analysis.

Industrial Significance The operational and analytic results of the Power System Equipment Module Test are significant to industry in several basic areas.

- Heat exchange to hydrocarbon working fluids and mixtures of hydrocarbon working fluids has been shown to be very stable at both subcritical and supercritical states. No thermal or hydraulic instability was observed with the various fluid states of the Rankine cycle used to model commercial power plant operations.

- Overall heat balance calculations done over the heating portion of working fluid Rankine cycle showed agreement to within $\pm$ 7 percent. This indicates:

  - enthalpy property data of the hydrocarbon fluids both above and below their critical state are valid for heat exchanger design purposes, and

  - mass flow rate ratios, geothermal brine to hydrocarbon working fluids, can be used and relied upon in optimization studies for commercial plant design.

- Overall heat transfer coefficients deviate little from those predicted by current stream analysis methods. The heat transfer coefficients in the supercritical region are about 10 percent higher than predicted, those in the subcritical region about 10 percent lower. This close correspondence validates heat exchange duty/area requirements as currently calculated. Further heat exchange design and scale-up from the sizes used for these tests, giving consideration to the information developed by these tests, will allow heater and condenser design to within 15 percent for applications with similar, nonfouling, geothermal brine characteristics.

- Pressure drop information developed indicates that the pressure drops experienced by the hydrocarbon fluids are about 20 percent greater than calculated. Further heater and condenser design and overall system design must include this consideration.

Conclusions Review of the operational and analytic results of the Power System Equipment Module Test allows several conclusions to be reached.

- The first operation of a supercritical Rankine cycle was successful. No injuries occurred to any operator and no damage occurred to any test equipment. Handling of the hydrocarbon fluids presented no undue hazard to the operators or the equipment, even though peening and welding operations were performed on the hydrocarbon system with the hydrocarbon at above atmospheric pressure.

- Operation of the test system in both supercritical and subcritical Rankine cycles was shown to be inherently stable, requiring no automatic control and allowing repeatable and accurate recording of operational data.

- Geothermal brine supply to the test system was steady although this brine supply came only from one production well. The lack of greater geothermal production caused a lower than design temperature brine supply to the test system limiting test operations at heat duties more than 5 percent above design. However, this does not affect the validity of the heat exchanger performance demonstrated by the test operations.

- The chemistry of the geothermal brine remained constant throughout the duration of the tests. The tests demonstrated the generally corrosive character of the brine from the East Mesa Geothermal Field. This corrosive character eliminated those goals of the test program directed toward determination and evaluation of both the scaling common to most geothermal brines and chemical methods of 'in situ' cleaning of brine exposed surfaces.

- The measured results from the hydrocarbon working fluid heat exchanger were input into a typical rating computer program that would be used by industry to design these heat exchangers. The computer program is owned by PFE Engineering Systems, Inc. and uses a stream-analysis procedure to calculate the shell-side heat transfer and pressure drop coefficients. This program is similar to other programs generally available to all contractors, manufacturers, and users of shell and tube heat exchangers.

The overall measured heat transfer coefficients of the heaters were determined to an accuracy which varies depending on the factors arising from data uncertainty considerations. Generally, the smaller the temperature driving force between the hydrocarbon working fluids and the geothermal brine, the less accurate the results. Run number 110 is selected here to illustrate the potential combined error inherent in the data. Table 2-1 summarizes the measured and calculated results of this run.

Table 2-1

SUMMARY OF RUN NO. 110

Exchanger Unit No.	Brine Duty (10^6 Btu/hr)	Hydrocarbon Duty Difference (%)	LMTD °F	Measured Overall Coefficient (Btu/hr-ft²°F)	Percent Uncertainty Error Q	LMTD	U
B1	3.37	-4.2	33.53	348.5	5.8	4.4	10.6
B2	2.20	-9.2	19.0	401.0	9.0	7.7	17.9
B3	1.55	-17.8	12.72	422.4	12.8	11.2	25.9
B4	1.24	-25.9	10.59	404.1	16.1	13.4	31.2
B5	2.14	-32.4	15.51	478.2	9.3	9.9	21.9
B6	5.05	-8.5	33.12	528.0	4.0	4.6	10.0

From the above table it is clear that the data from units B1 and B6 will be the most accurate. All the heat exchange units have the same tube and shell side configurations except for B6. B6 has the same number of tubes but has double segmental baffles while the others have single segmental baffles. Since these units were in series, the mass flow rate was identical in each unit, but the velocity of the hydrocarbon increased unit to unit as it was heated. The main difference in the performance of these units is that as the hydrocarbon is heated, the temperature versus enthalpy profile bows nearly meeting the nearly straight profile of the brine. The minimum temperature "pinch" for this run was 10.2°F occurring between units B2 and B3. There were other runs with pinches of less than five degrees Farenheit. This low pinch point temperature difference generally makes the accuracy of the data for B2 through B5 quite low. This type of problem is inherent in the working fluid and the precision of the instrumentation and is not due to the manner in which the operating data was taken.

By reviewing Table 2-1, it can be seen that the overall heat transfer coefficient varied from 348.5 to 528.0 Btu/hr ft^2-^{o}F. These values are consistent with values which were obtained with the PFR shell and tube program, SAT-1. This comparison is summarized in Table 2-2.

Table 2-2

COMPARISON OF HEAT TRANSFER COEFFICIENTS - RUN 110

Unit No.	U-Measured	U-Calculated	% Difference
B1	348.5	390.0	+ 11.9
B2	401.0	397.0	- 1.0
B3	422.4	449.1	+ 6.3
B4	404.1	406.7	+ 0.6
B5	478.2	480.2	+ 0.6
B6	528.0	460.0	- 12.9

The low percentage difference from units B1 to B6 indicates that if competent organizations specializing in the design of heat exchangers would be given the basic process, thermodynamic, and transport data, the heaters and condensers could be designed to better than 15 percent accuracy for East Mesa and other geothermal sites with brines which have similar, minimal fouling characteristics.

- The pressure drop of the isobutane through the exchangers increased from units B1 to B5 because the density decreases, thereby providing an increased velocity. The pressure drop for these units was calculated using the conditions of run 110, using the above-mentioned computer program, and compared to the overall measured values. A value of 90 psi was calculated as compared to the 109 psi measured. Therefore the specification for this type of heat exchanger should allow for pressure drops about 20 percent higher than otherwise expected.

- The effect of fouling on the heat exchanger data was examined to determine its significance on the data. Fouling could have occurred on the brine or the hydrocarbon side. The overall heat transfer coefficients were plotted as a function of time. From this plot, it appears there is a drop off in the performance starting in December. After visual inspection of the tube side it was determined that the brine did not foul. There may have been fouling on the hydrocarbon side. Inspection of the hydrocarbon working fluid indicated the presence of a black substance with the appearance of iron oxide and water mixed with the isobutane. The effect of metallic fouling on the data runs 53-165 appeared to be insignificant. Since the heat exchange units are of fixed tube-sheet design, there is no possibility to verify this fouling until the shell sides are cut open.

- The data from the highest temperature heat exchanger is extremely important because the isobutane was heated beyond its critical temperature. Theoretically it can be shown that heat transfer should dramatically increase at the critical point. The units were not instrumented to obtain internal, step-wise data; therefore this effect could not be confirmed.

- The determining overall condensing heat transfer coefficients, 250 Btu/hr ft^2-^{o}F for isobutane and 190 Btu/hr ft^2-^{o}F for 80/20 isobutane-isopentane mixture are within expected industrial range for the process conditions. However, this condenser data is of limited value for two major reasons. First, fouling on the cooling water side was so high that it lowered the overall heat transfer coefficients much lower than can be considered normal by industry. Secondly, the water temperatures were much higher than would ever be allowed in a power producing cycle.

- The chemistry of the cooling water in the cooling tower was easily monitored but required chemical addition to minimize calcium carbonate fouling. The cleanliness of this water was difficult to maintain due to the light sand and dust existing in the Imperial Valley environment.

- Control problems discovered during test operations were solved in the field primarily by manual adjustment to the controller set points. These control problems were due in one case to slag and machined chips left in the heat exchangers during fabrication, and in the other by excessive fouling caused by higher than design cooling water temperatures.

Recommendations Review of the operations of the Power System Equipment Module Test and of the data acquisition and analysis efforts supports the following recommendations. These recommendations are divided into two groups. The first group addresses both practices and problems anticipated in commercial plant operation. The second group of recommendations suggests additional modifications appropriate for further operations with the test equipment used.

I.

- Current Heat Transfer procedures should be used to design the heaters and condensers.

- Temperature differences (pinch points) between hot and cold streams as small as $5^{o}F$ are thermally stable and may be used during optimization of the overall plant and heat exchanger design.

- A sump or pit should be included by design to:

  - handle any discharges during plant cleaning and washing;

  - have the capacity to hold cold brine from the system during plant initial heat up;

  - serve as a reservoir for any fluids removed from the system during maintenance and repair operations.

- Primary brine/hydrocarbon heat exchanges should be two pass on the tube side (U tubes) to eliminate expansion problems and simplify tube-side piping. Shell and tube heat exchangers with removable bundles (or shells) should be used so that both the shell and tube sides can be mechanically maintained and to allow the bundle to freely expand.

- Heat exchangers of varying size in the heater train should be considered. As a hydrocarbon is heated the size and configuration of each exchanger can then be optimized.

- The control system for cooling water to the condenser should operate by sensing the flow of cooling water rather than condenser pressure or condenser outlet temperature.

- A knock-out pot or drum should be installed at circulation pump suctions to enable removal of any foreign material which may be circulating in the system.

- A reflex gauge glass should be installed on all cooling heat exchangers and at system low points to verify that no liquid accumulates thereat.

- Drip legs should be installed on the condenser shell bottom to collect any solids or liquids which may collect at the bottom of the condenser. A reflex gauge glass should be installed on these drip legs.

- If any vertical pumps are used, a bleed line should be installed from the bottom of their pump outside housing to grade to enable removal of any impurities which may settle at that point.

- A different design should be used for the welded joint between the tube sheet and tubes in all hydrocarbon heat exchangers. The tube sheets should be beveled to accept a fillet weld. Seal welds are not sufficient. Manufacturing procedures should be considered which eliminate the possibility of the brine entering the hydrocarbon loop and vice versa; double-tube sheet designs should be considered.

- Closer inspection should be performed during manufacture of equipment. Greater stress should be placed on onsite inspection during manufacture and cleanliness after testing in the fabrication shop.

- Inspection openings should be provided in each heat exchanger and vessel.

- All threaded valves and fittings in brine service should have exposed male ends with end caps. All female threads and plugs should be eliminated.

- Flow alarms of the paddle type should not be used in any service. A differential pressure switch across an orifice plate in conjunction with a flow meter would have a greater reliability.

- A small brine bleed line should be installed to hydrocarbon heat exchangers so a controlled (small) amount of brine (heat) could be admitted to the exchangers to "boil off" any hydrocarbons to the condensing side when repairs to or maintenance of that heat exchanger system is necessary.

- An online gas chromatograph should be installed in any hydrocarbon system. This would serve to provide ready recall of fluid composition and eliminate expansion problems encountered during extraction of mixed hydrocarbon fluid samples.

- Consideration should be given in using an appropriate corrosion allowance on the brine side of the heaters for the East Mesa site if carbon steel tubes are to be used. A value of five mills per year appears appropriate.

II.

- The cooling tower water bypass should be eliminated and all the cooling water be cooled to its lowest temperature. Should various temperatures be desired for experimental purposes, a bypass should be installed directly to the cooling water circulation pump suction.

- The rupture disc bypasses around the throttle valve should be eliminated. These were useless.

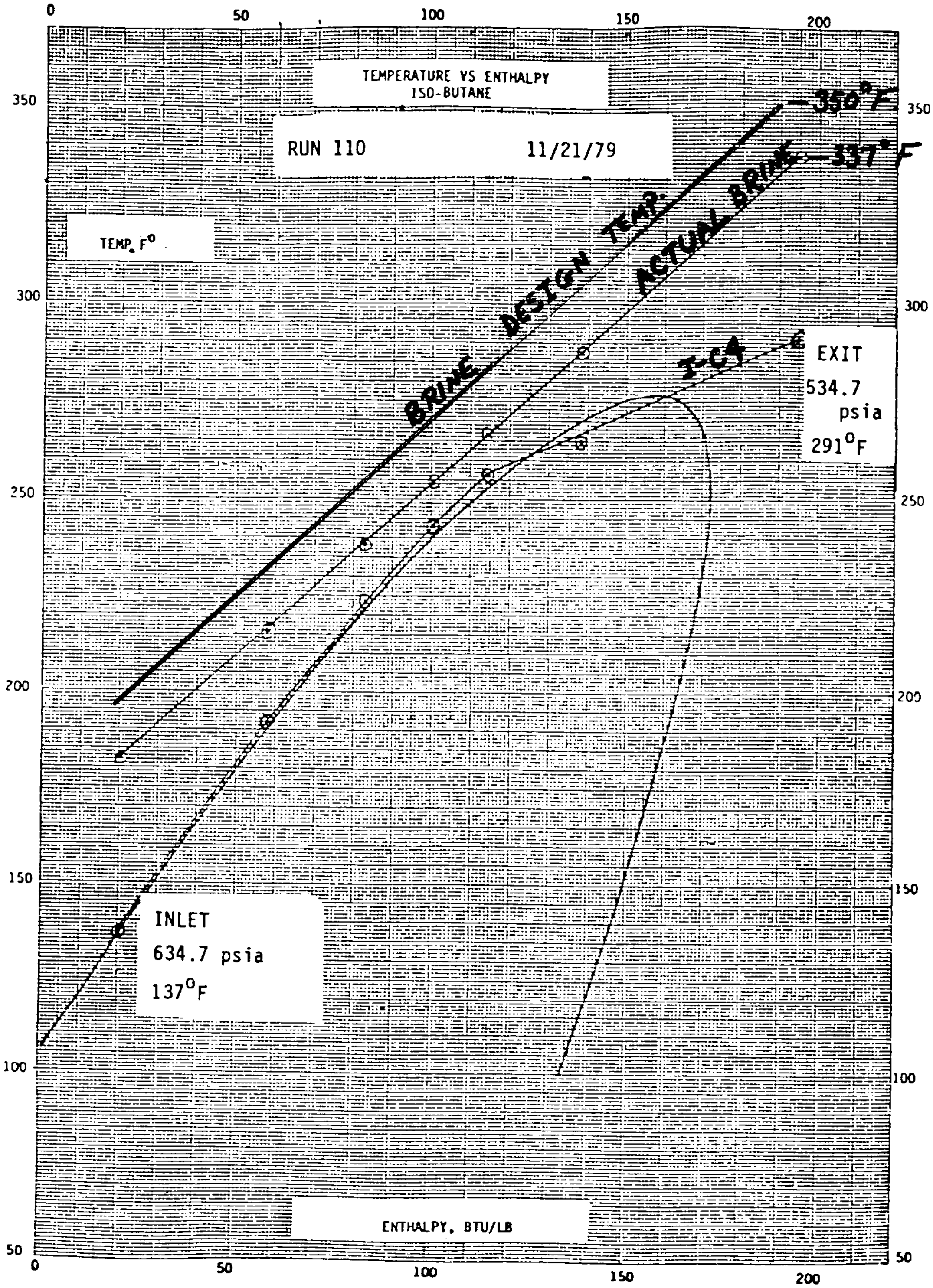
- All the turbine meters used on the project should be carefully reviewed; larger sizes should be considered. The pressure drop through the meters in the cooling water service was excessive.

- Differential pressure gauges should be installed across the orifice plates used for brine and hydrocarbon flow control. These can be easily read and used with the orifice plate curves to confirm flow rates.

- The brine emergency shutdown valve on the brine outlet from the hydrocarbon heat exchangers should be eliminated. The inlet emergency shutdown valve is sufficient.

- A manual bypass should be installed in parallel with the inlet emergency shutdown valve so that valve may be "exercised" daily without interruption of the brine flow.

Reliability tests on equipment and total system operation should be the prime consideration of future tests. It has been demonstrated the system concept is sound, and that heat exchange coefficients are confirmed to sufficient accuracy to aid commercial plant design and construction. Prolonged tests to demonstrate brine supply reliability, control valve life, scaling and corrosion factors, and mechanical equipment reliability should be considered.



Shown at the meeting by Joseph M. Pundyk, PFR Engineering Systems, Inc., 4676 Admiralty Way, Marina del Rey, CA 90291.

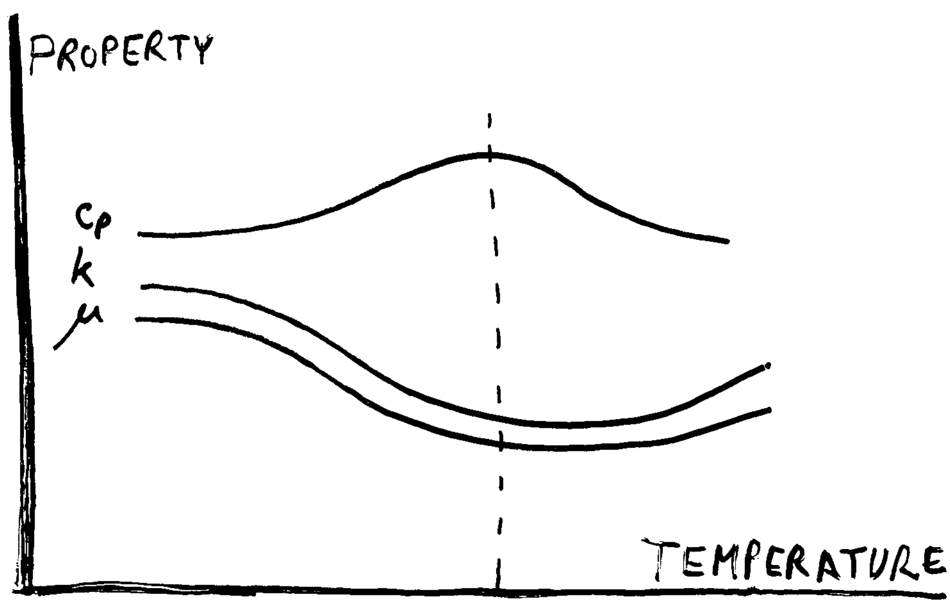
HEAT TRANSFER IN CRITICAL REGION

FILM COEFFICIENT IS FUNCTION OF:

- G – MASS VELOCITY
- d_o – TUBE DIAMETER
- k – THERMAL CONDUCTIVITY
- μ – VISCOSITY
- C_p – HEAT CAPACITY

SHELL SIDE IN TURBULENT FLOW

$$h \sim G^{2/3} \left(\frac{k}{\mu}\right)^{2/3} \left(\frac{C_p}{d_o}\right)^{1/3}$$



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PRELIMINARY HEATER DESIGN IMPLICATIONS

1- DESIGN TO TEMA "R" STANDARDS

2- SPECIFY "WELDED AND ROLLED"
- TUBE TO TUBE SHEET JOINT
- TUBE INSERTS OF S/S @ INLET OF BRINE EXCH.

3- EXAMINE USE OF U-TUBED TWO-PASS SHELLS

4- USE "NO" FOULING FACTORS FOR EAST-MESA SITE

5- CURRENT HEAT TRANSFER METHODS ARE CONSERVATIVE - USE STEPWISE PROC.

6- CURRENT PRESSURE DROP CALCS. SHOULD BE PERFORMED STEPWISE

Shown at the meeting by Joseph M. Pundyk of PFR Engineering Systems, Inc.

A HEAT EXCHANGER PROCESS FOR REMOVAL OF H_2S GAS

CONTRACT NO. RP1197-2

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I. Introduction A heat exchanger process has been developed for the removal of H_2S and other noncondensable gases from geothermal steam. The process utilizes a heat exchanger to condense water from geothermal steam while allowing H_2S and other noncondensable gases to pass through in the vapor phase. The condensed water is evaporated to form a clean steam from which over 90 percent of the H_2S and other noncondensable gases have been removed.

Some of the important advantages of the heat exchanger process are shown in Table 1. The system can be located upstream of a power plant turbine which eliminates much of the potential for corrosion, as well as the requirement for removing H_2S from water collected in the main condenser. Since almost all noncondensables are removed, much less steam is needed for air ejector operation. The heat exchanger process is simple: it has no chemical addition requirements or sludge by-products and utilizes standard equipment found in many power plant applications. The regular power plant operators and maintenance crews can easily understand and run the system with minimal attention. Capital and operating costs are competitive with those for currently available H_2S-abatement technology, although significant economic advantages over downstream abatement processes may result due to the use of clean steam in the turbines.

Table 1. Advantages of the Heat Exchanger H_2S Removal Process

Upstream Abatement
- Clean steam to turbine
- Reduced air ejector requirements
- No treatment needed for main condenser water

Simple Operation
- No chemicals
- No sludge
- Minimal operator attention

Reasonable Costs
- Competitive with downstream abatement techniques
- Reduction in overall power plant costs with clean steam

Under the contract to EPRI, a 1000-lb steam/h heat exchanger test unit was designed and constructed at Unit 7 of The Geysers Power Plant. Operation began in March 1979. The test unit was run under widely varying conditions to demonstrate H_2S removal, heat transfer properties, and related process characteristics.

Based on data from the test unit and other EPRI-sponsored studies, alternative conceptual designs for the heat exchanger process were developed for a 55-MW power plant. Design criteria and equipment requirements were determined for a selected design. Capital and operating costs for a large-scale system were also estimated.

II. Heat Exchanger Test Unit

A. Description The test unit is located at The Geysers Power Plant, Unit 7. Wellhead steam at Unit 7 varies from saturated to superheated conditions, with typical temperatures of about 340°F to 350°F. H_2S concentrations are commonly 200 to 300 ppm with total noncondensable gas concentrations ranging from 2000 to 5000 ppm. About 80 percent of the noncondensable gas is CO_2. Besides H_2S and CO_2, other constituents include NH_3, N_2, H_2, CH_4, and boron. Figure 1 shows the test unit configuration.

Geothermal steam enters the shellside of the heat exchanger, where it is selectively condensed at its saturation pressure. The condensate will dissolve some of the noncondensable gases contained in the steam, but about 98 percent of all gases, including CO_2, NH_3, H_2, and N_2, will remain in the vent gas stream. Depending on steam compositions and process operating conditions, 90 to 99 percent of H_2S will remain in the vent stream.

The condensate is reduced to a lower pressure and allowed to flash in the tubeside sump of the heat exchanger. This provides the necessary temperature driving force across the heat exchanger. The condensate within the tubes is partially vaporized to clean steam which discharges from the sump. The clean steam from the sump and the vent gas exiting the top of the shellside of the heat exchanger are released into the Unit 7 cooling tower basin.

B. Test Objectives The testing program for the 1,000 lb/h test unit was set up to accomplish both primary and secondary objectives. The primary objectives of the test program were to demonstrate H_2S removal capabilities and heat transfer performance of the heat exchanger. The secondary objectives of the program were to

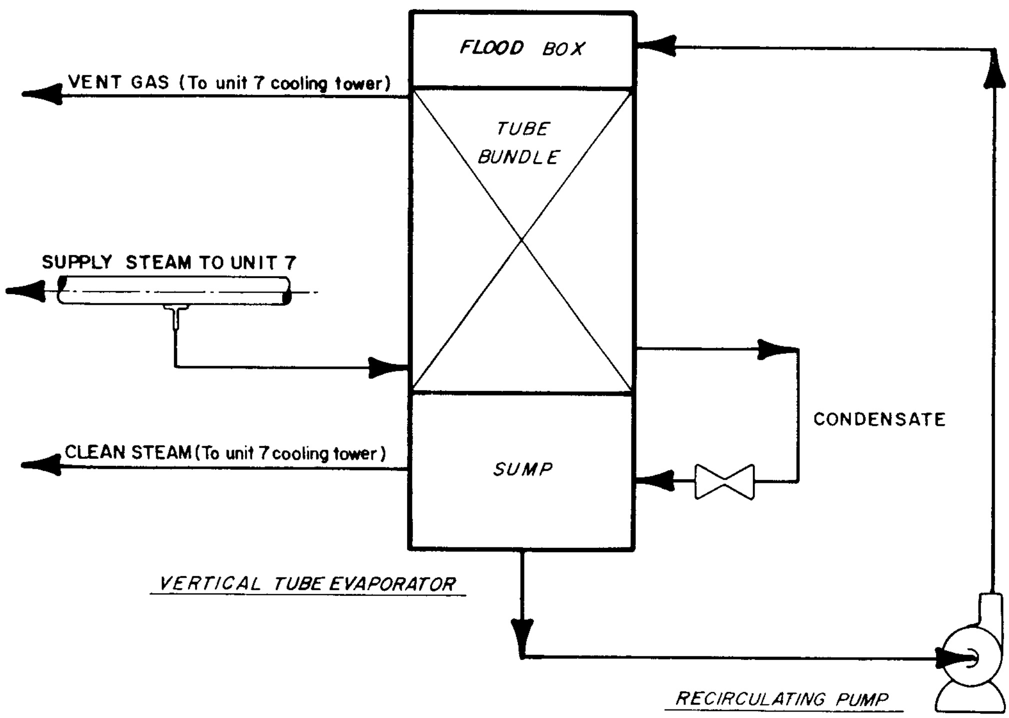

FIGURE I. HEAT EXCHANGER TEST UNIT CONFIGURATION AT THE GEYSERS POWER PLANT, UNIT 7.

develop data for use in the design of larger heat exchangers.

C. Test Results The test unit has operated since March of 1979. Data have been collected for approximately 68 days, during which time the unit has been in operation on a continuous basis for as long as 10 to 15 days. Besides H_2S removal and heat transfer performance , the pilot plant was tested for total noncondensables removal, transient response, gas injection, and parametric evaluations of ΔT and vent rate.

Removal of H_2S is determined by how much H_2S enters the liquid phase as the steam condenses on the outside of the tubes. The amount of H_2S absorbed at equilibrium is controlled by three factors: the partial pressure of the gas in the vapor phase, the mass ratio of vapor to liquid in contact with each other, and the pH of the liquid solution. The pH, however, depends in a complex way on the amount of gases that dissolve. As CO_2 and H_2S are dissolved the pH decreases due to hydrolysis of CO_2 and H_2S in the liquid phase:

$$CO_2 + H_2O = H^+ + HCO_3^- \tag{1}$$

$$H_2S = H^+ + HS^- \tag{2}$$

while the dissolution of ammonia leads to the capture of hydrogen ions and an increase in pH:

$$NH_3 + H^+ = NH_4^+ \tag{3}$$

As a result, the major variables that affect H_2S removal are temperature, pressure, gas composition, and the percent of inlet steam vented. The only variable that could be controlled effectively within the limitations of the test unit was the percent vent rate.

Figure 2 shows H_2S removal as a function of percent vent rate. The H_2S removal varied from 90 to 99 percent with an average value of 94 percent. There is a slight trend showing increased H_2S removal with increased vent rate; this is predicted since increasing the vent rate reduces the partial pressure of H_2S in the vapor phase. On the other hand, the data in Figure 2 show a high degree of scatter. The scatter is attributed mostly to highly variable concentrations of H_2S, NH_3, and other gases in the inlet steam. Based on recent field tests at The Geysers, changes in concentration by a factor of three or more can occur within a short period of time.

The heat transfer properties of the test unit were evaluated by calculating an overall heat transfer coefficient (HTC), under various conditions. The coefficient is defined by the following relationship:

$$HTC = \frac{Q}{A\Delta T} \tag{4}$$

where Q = heat load defined by the amount of steam condensed
A = heat transfer area
ΔT = temperature difference between the tubeside and shellside

The major factors expected to affect HTC measurements are the noncondensable gas concentrations, mass flow rate, presence of scale, and the percent vent rate. The effect of changing the percent vent rate was extensively tested in the unit. It was expected that the HTC would increase with vent rate since higher vent rates result in increased sweep velocities across tubes, thus minimizing the blanketing effects of noncondensables.

Figure 3 shows the variation in the HTC with percent vent rate. In general, values ranged from 300 to 1000 Btu/(h·ft^2·°F) with an average of about 576 Btu/(h·ft^2·°F). Large variations in the HTC values were experienced and no consistent correlation between HTC and vent rate was apparent. This may be explained by highly variable noncondensable concentrations and possible leakage across the bottom tubesheet. No effects attributed to fouling of tubes were noted.

The predicted HTC value for the test unit was about 900 Btu/(h·ft^2·°F). Lower values may have been calculated for the test unit for a number of reasons. First, the test unit was too small to be designed for proper sweep velocities. As discussed previously, higher sweep velocities are necessary to minimize the effect of blanketing of tubes. Second, due to physical limitations, ΔT measurements were between inlet and clean steam lines. These ΔT values would be higher than actual tubeside-shellside ΔT's. Lower calculated HTC values would result. Finally, two of the 50 heat exchanger tubes were crushed, possibly blocking flow and reducing heat transfer area. Reduced heat transfer area would also result in lower calculated HTC values.

Other major test results for noncondensables, transient conditions, gas injection and parametric tests are summarized in Table 2. Total noncondensables removal in the test unit was found to be greater than 99 percent for all conditions. This is based on field test methods which compare gas to liquid volume ratio in condensed inlet and clean steam samples. Transient tests were done to simulate conditions that could be experienced if the heat exchanger was installed upstream of a turbine generator. The tests, which included startup, sudden decreases and increases in clean steam flow, sudden increase and decrease in vent gas flow resulted in stable, predictable operation of the heat exchanger. Only the sudden increase in the clean steam flow caused a shutdown and this could be solved by using a standard control scheme for commercial

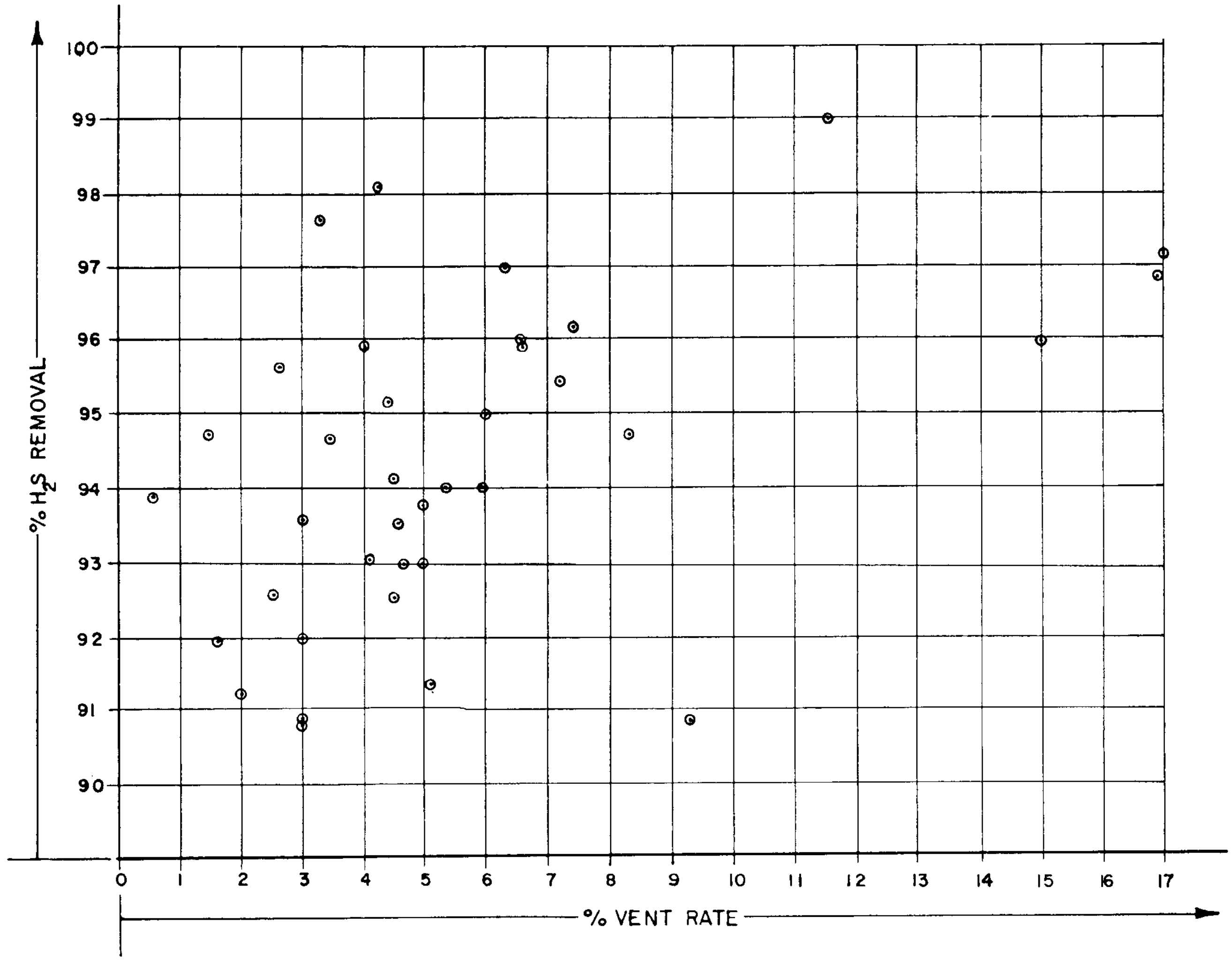

FIGURE 2. TEST UNIT PERFORMANCE: H_2S REMOVAL vs. VENT RATE.

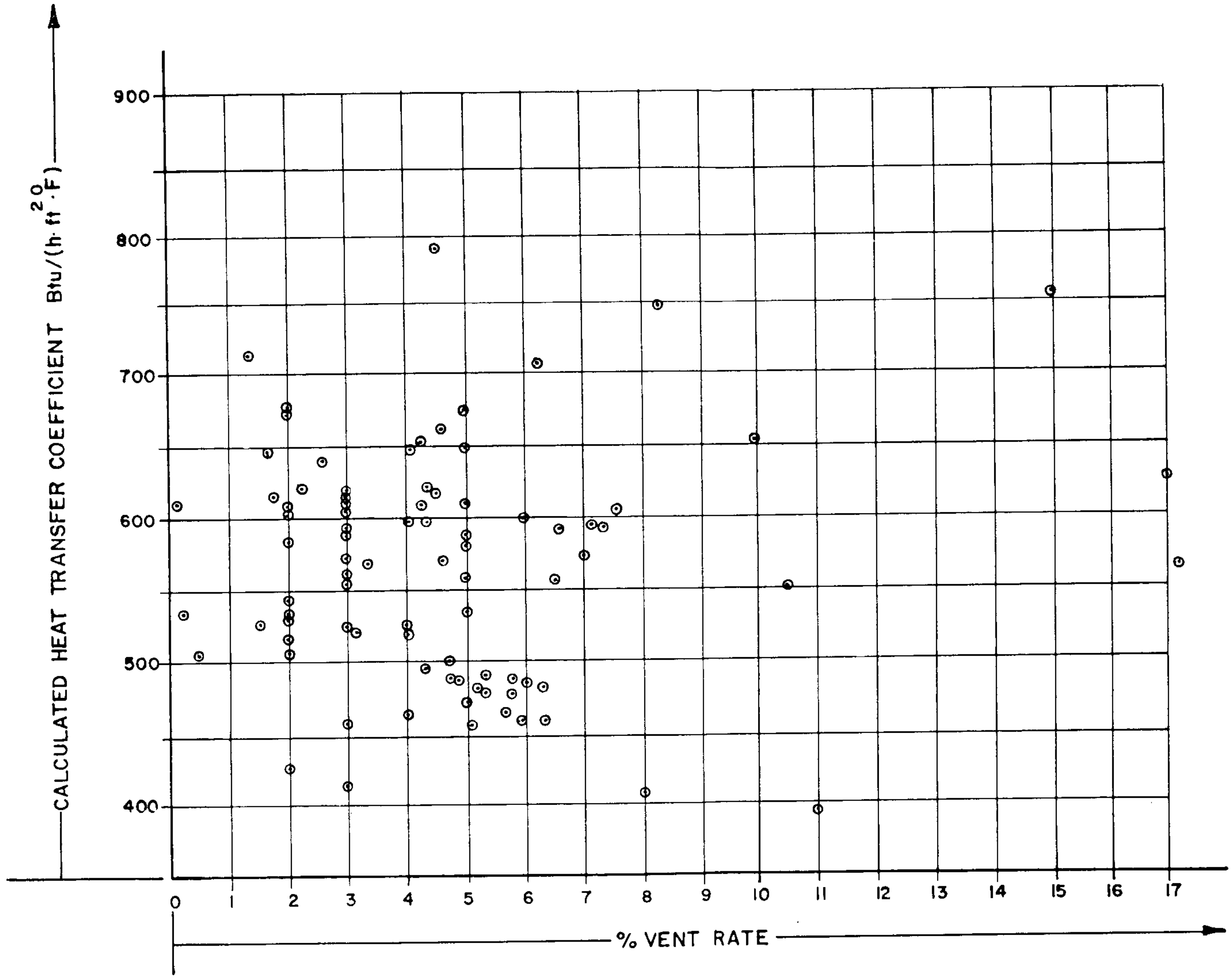

FIGURE 3. TEST UNIT PERFORMANCE: COEFFICIENT of HEAT TRANSFER vs. VENT RATE.

power plant operations. Increasing the inlet concentrations of NH_3 and H_2S by up to four times their normal concentrations had little effect on H_2S removal or heat transfer; however, the limited runs made under these inlet conditions, which could vary significantly with time, do not allow conclusions to be made here. The parametric tests varying ΔT were consistent with predictions. Data showed that increasing ΔT from 5^oF to 10^oF doubled the clean steam produced but had negligible effect on H_2S removal or heat transfer properties. Parametric tests involving percent vent rates have been presented previously.

Table 2. Other Major Test Results

Noncondensables Removal

- Greater than 99 percent under all conditions

Transient Effects

- Tested conditions simulating startup, sudden opening and closing of clean steam valve, sudden opening and closing of vent gas valve, sudden closing of inlet steam valve, pump trip.
- No unpredictable results
- Smooth heat exchanger response in all cases except sudden opening of clean steam valve.

Gas Injection

- Increased NH_3 and H_2S up to four times
- No significant effect on H_2S removal or heat transfer properties
- Limited number of runs

ΔT Effects

- ΔT tested between 5 and 10^oF
- Clean steam flow rates changed as predicted
- No effect on H_2S removal or heat transfer properties.

III. Commercial-Scale Design The most effective way of utilizing this heat exchanger process in a full-scale power generation application similar to The Geysers would be to use an upstream, multistage heat exchanger system. Figure 4 shows one possible scheme for such an application. The well steam first enters the first-stage heat exchanger where most of the H_2S and other noncondensables are removed from the steam. Approximately 95 percent of the incoming flow leaves the first-stage heat exchanger as clean steam, supplying steam to a turbine generator unit. The vent stream from the first-stage condenser (which includes approximately 5 percent of the total incoming steam and almost all of the incoming H_2S and other noncondensables) is processed by a second-stage heat exchanger. The clean steam from this second stage is used to drive a second turbine generator unit. Almost all of the H_2S and other noncondensables and a very small percent of the steam entering the first-stage heat exchanger are in the second-stage vent stream. This vent stream can be treated for ultimate disposal of the H_2S by some process such as the Stretford process. The Stretford process is a proven commercial process which can easily convert highly concentrated streams of H_2S into elemental sulfur. The second-stage vent stream could possibly be used to drive a third turbine generator unit located upstream of the H_2S conversion process. This turbine would have to be constructed of materials suitable for the high concentrations of H_2S in this flow stream.

Figure 5 shows another possible scheme for an upstream, multistage heat exchanger system in a power generation application. In this scheme the clean steam from the first-stage heat exchanger is used to drive the turbine generator unit. The clean steam from the second-stage unit is used to drive the condenser vacuum system and also provides process heat, if required, for the H_2S conversion process. The vent stream from the second-stage unit goes directly to an H_2S conversion process such as the Stretford process. The scheme shown in Figure 5 can more easily be used in a retrofit application for power plant designs similar to those at The Geysers; however, both schemes could be utilized in new plant design applications.

IV. Estimated Costs for Commercial-Scale Application The estimated costs of a commercial-scale heat exchanger system were determined in a recently completed study. The cost model was based on a system that would be compatible with a typical Pacific Gas and Electric Company (PG&E) 55-MW power plant unit at The Geysers. The design scheme in Figure 5 was used in developing the cost model. This scheme includes a two-stage heat exchanger system with the first stage supplying clean steam to the turbine generator unit and the second stage supplying clean steam to the condenser vacuum system and for use as process heat in the Stretford plant. The second-stage vent stream is processed by a Stretford plant which converts this highly concentrated stream of H_2S into elemental sulfur. Tables 3 and 4 present the design criteria and the performance factors used in developing this cost model. The design criteria were provided by PG&E. The performance factors were based on detailed theoretical studies related to this heat exchanger process and the results of experimental field tests.

The major equipment items are the first- and second-stage heat exchangers and the recirculating condensate pumps. The total required first-stage surface area was 155,400 ft^2, which

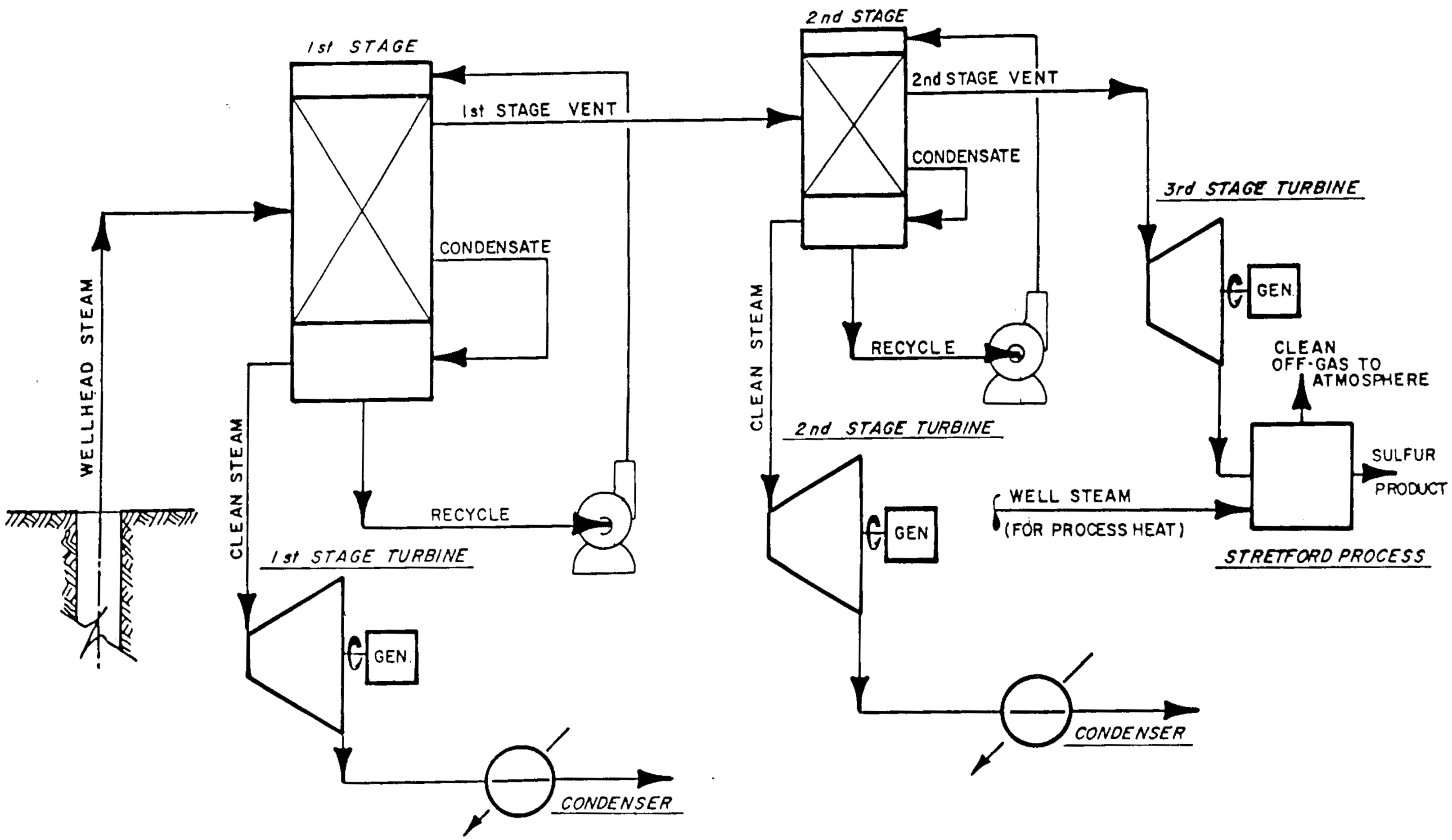

FIGURE 4. MULTISTAGE UPSTREAM APPLICATION OF THE H_2S REMOVAL HEAT EXCHANGER PROCESS.

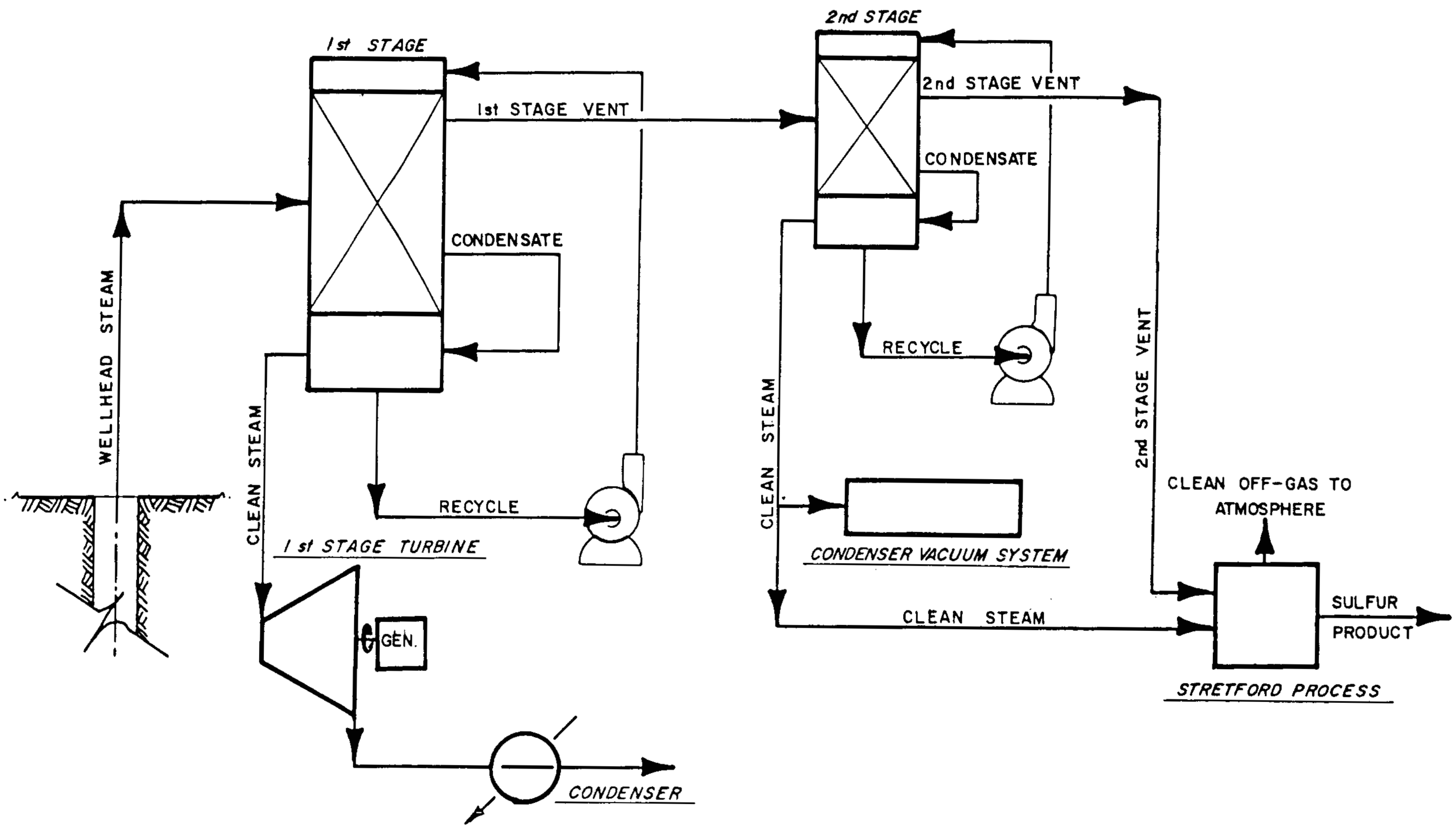

FIGURE 5. ALTERNATE MULTISTAGE UPSTREAM APPLICATION OF THE H_2S REMOVAL HEAT EXCHANGER PROCESS.

Table 3. Design Criteria

Well steam conditions:	
pressure	115 psig
temperature	350°F
noncondensable loading	0.5%
Turbine inlet steam conditions:	
pressure	saturation
temperature	338°F minimum
noncondensable loading	0.01% maximum
full load flow rate	1,100,000 lb/h
Maximum heat exchanger tube bundle size:	
40 feet long by 12 feet diameter (Shipping constraint due to remote location of The Geysers)	
Condenser vacuum system requirements:	
pressure	90 psig
flow rate	20,000 lb/h
Process steam to Stretford unit:	
flow rate	5,000 lb/h

Table 4. Performance Factors

Overall heat transfer coefficient	600 Btu/(h·ft^2·°F)
First-stage vent rate	5 percent
Second-stage vent rate	60 percent
Tubeside flow rates	1 1/2 gpm/tube

resulted in three first-stage heat exchangers, each with a tube bundle 37 feet long and 11 feet in diameter. The total required second-stage tube surface area was 3638 ft^2, which resulted in one second-stage heat exchanger with a tube bundle 19.5 feet long and 4 feet in diameter. The first-stage pumping configuration was assumed to be four pumps in parallel servicing the three heat exchangers, with one of these pumps being a spare. The pumping power requirements for each pump was 64 hp. The second-stage pumping configuration was assumed to be two pumps in parallel, with one of these pumps being a spare. The pumping power requirements for each pump was 5.2 hp. 304 stainless steel was selected as the material of construction for the heat exchangers, pumps, and related piping.

In addition to the heat exchangers and pumps, the other items included in the cost model were insulation, piping and valves, support structures and foundations, electrical equipment, instrumentation and controls, engineering costs, and a Stretford plant sized for this application. Table 5 summarizes the cost model.

The estimated system costs based on the developed cost model are summarized in Table 6. The estimated heat exchanger system capital cost is 5.6 million dollars. The estimated Stretford plant capital cost is 2.6 million dollars.

Table 5. Cost Model Summary

First-stage heat exchangers:	
Number of heat exchangers	3
Tube surface area per heat exchanger	51,800 ft^2
Tube bundle height	37 ft
Tube bundle diameter	11 ft
Material	304 stainless steel
Second-stage heat exchangers:	
Number of heat exchangers	1
Tube surface area	3638 ft^2
Tube bundle height	19.5 ft
Tube bundle diameter	4 ft
Material	304 stainless steel
First-stage pumps:	
Number of pumps	4 (3 operating, 1 spare)
Required pumping power per pump	64 hp
Material	304 stainless steel
Second-stage pumps:	
Number of pumps	2 (1 operating, 1 spare)
Required pumping power per pump	5.2 hp
Material	304 stainless steel
Piping and valves:	
Material	304 stainless steel
Instrumentation and controls:	
Control valves, level controllers, flow controllers, and instrumentation	suitable for process requirements
Stretford plant:	
H_2S processing requirement	240 lb/h

The total capital cost, including the Stretford plant, is 8.8 million dollars. The total estimated annual cost, including annual capital cost payments and operating and maintenance costs, is 1.9 million dollars.

Table 6. Estimated Cost Summary of 55-MW Heat Exchanger H_2S Removal System

Capital cost of heat exchanger system	$5,600,000
Capital cost of Stretford plant	2,600,000
Total capital cost	$8,200,000
Annual operation and maintenance cost	$ 400,000
Annual capital cost payment	1,500,000
Total annual cost	$1,900,000

Notes for Table 6.

1. All costs are ±25 percent.
2. Heat exchanger system capital cost includes heat exchangers, shipping, erection, pumps, valves, piping, instrumentation, insulation, foundations, and engineering.
3. Annual operation and maintenance costs include 2 percent of heat exchanger system capital cost, 10 percent of Stretford plant capital cost, pump energy costs based on $0.03 kWh, and an assumed on-line time of 8000 h/yr.
4. The annual capital cost payment is assumed to be 18 percent of the total capital cost.

PRELIMINARY EVALUATION OF THE COPPER SULFATE PROCESS FOR REMOVAL OF HYDROGEN SULFIDE OVER A RANGE OF GEOTHERMAL STEAM CONDITIONS

Research Project Number RP1197-3

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The experimental work and economic analyses required for a preliminary evaluation of EIC's Copper Sulfate Process for a range of geothermal steam conditions have been completed. A series of six scrubbing runs was carried out over a range of steam conditions and scrub solution compositions expected to represent the extremes likely to be encountered in practice and high degrees of H_2S removal were obtained in all cases. Solids produced in these runs were subjected to liquid-solid separation and regeneration tests to determine the influence of scrubbing conditions on the kinetics of subsequent steps, and capital and operating cost estimates were developed for the extremes of conditions evaluated.

Test results show, as expected, that the kinetics and stoichiometry of the scrubbing reactions are complex: the rates and extent of the primary and secondary reactions are functions of scrubber operating temperature (pressure), scrub solution pH and copper content, and solids residence time. Relative to The Geysers' average conditions, operation at higher pressures leads to increased H_2S and decreased NH_3 removal efficiencies. At lower pressures, higher pH's and/or copper contents or longer vapor-liquid contact times are required to obtain comparable H_2S removal efficiencies, while NH_3 removal efficiencies are improved at comparable pH's.

The solids obtained from each scrubbing run were produced under a range of conditions since scrub solution compositions were varied, as was solids residence time throughout. Within the range of variables tested, the trend is toward improved liquid-solid separation behavior for solids produced at higher pressures. Even though the range of compression times varied by a factor of two, the solids produced at the lowest pressures still settled rapidly enough and with sufficient overflow clarity to indicate that simple decantation would be the optimum approach for this step.

The results of regeneration tests on these solids were much more variable, however, showing a definite correlation between scrubbing conditions and regeneration kinetics: solids produced at lower pressures were more readily regenerated than those produced at higher pressures. While complete regeneration was obtained in all cases, the times required varied by a factor of five at equal reaction temperatures and oxygen partial pressures. We believe that both liquid-solid separation and regeneration kinetics are determined by the nature of the solids formed in the scrubber, particularly the specific surface or average particle size, as well as their chemical composition.

These data were used as the bases for determining system configurations as well as capital and operating costs for geothermal steams differing from The Geysers conditions. For purposes of this evaluation all components of the process were grouped according to their sensitivity to either total steam flow rate or to the total amount of H_2S which is removed. Process configurations were similar for all cases evaluated, except that regeneration by oxidation using compressed air is preferred for steams containing lower H_2S concentrations.

The capital costs of the scrubber and its auxiliaries increase as steam pressure decreases since larger amounts of steam must be treated per unit of generating capacity. The capital costs of all other plant sections increase with the amount of H_2S removed and with decreasing steam pressure. Direct operating costs also increase with the amount of H_2S removed and with decreasing steam pressure. They are also sensitive to the amount of NH_3 present in the steam, particularly where the H_2S content of the steam exceeds about 500 ppm.

For steam of The Geysers' average compositions, direct operating costs are approximately 1.0 mill/kWh for a system capable of reducing emissions to 50 gm/mWh, corresponding to 97% H_2S abatement. Capital charges increase total operating costs to 3.5 mill/kWh. Capital charges dominate total operating costs for all cases evaluated, but direct operating costs were generally lower than the cost of peroxide alone required for supplemental abatement of condensate from downstream treatment systems. Direct operating costs for systems containing 2500 ppm H_2S, which range from approximately 4-6 mill/kWh, could be halved by modifying the process configuration to recover ammonia for reuse.

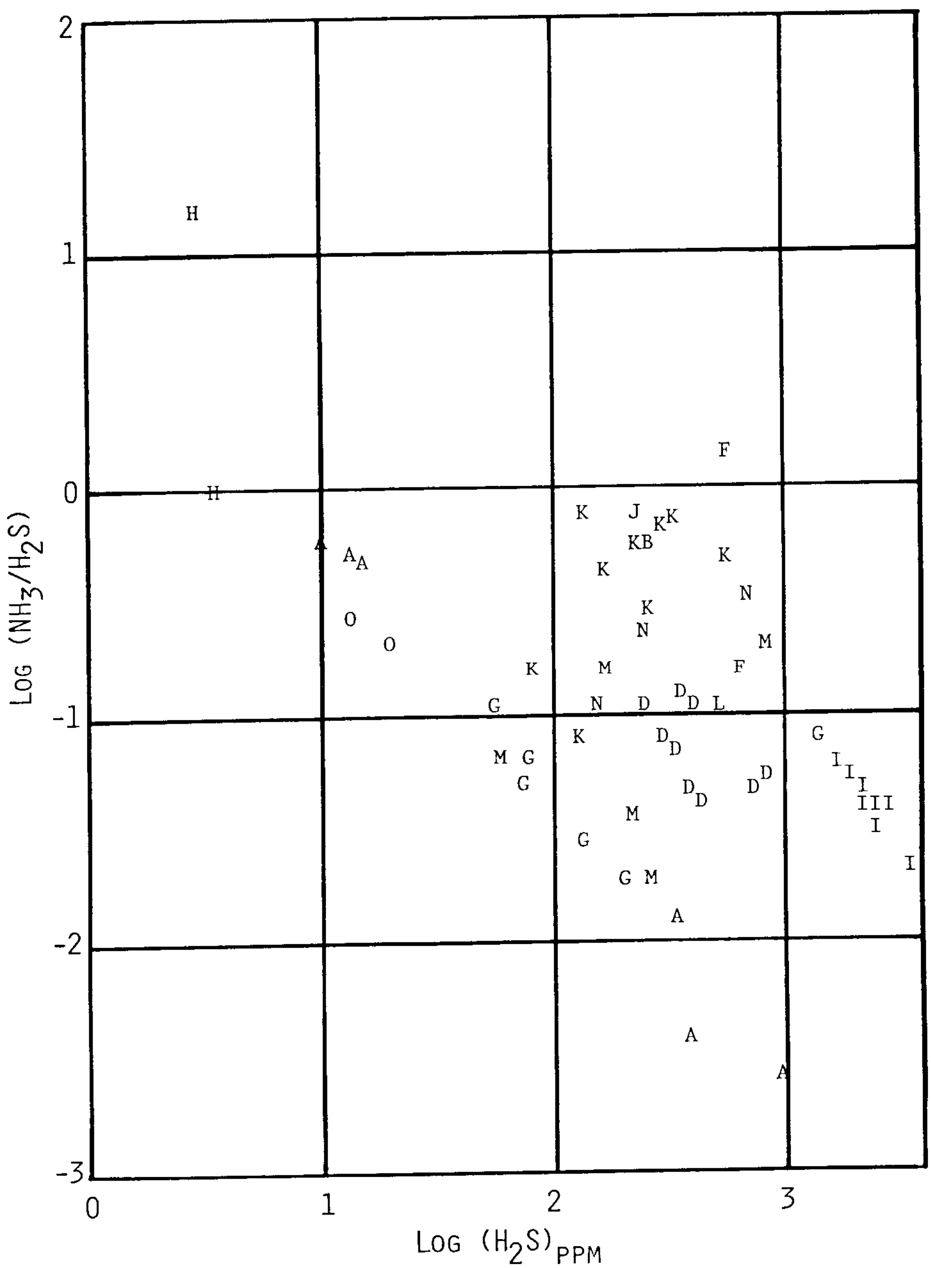
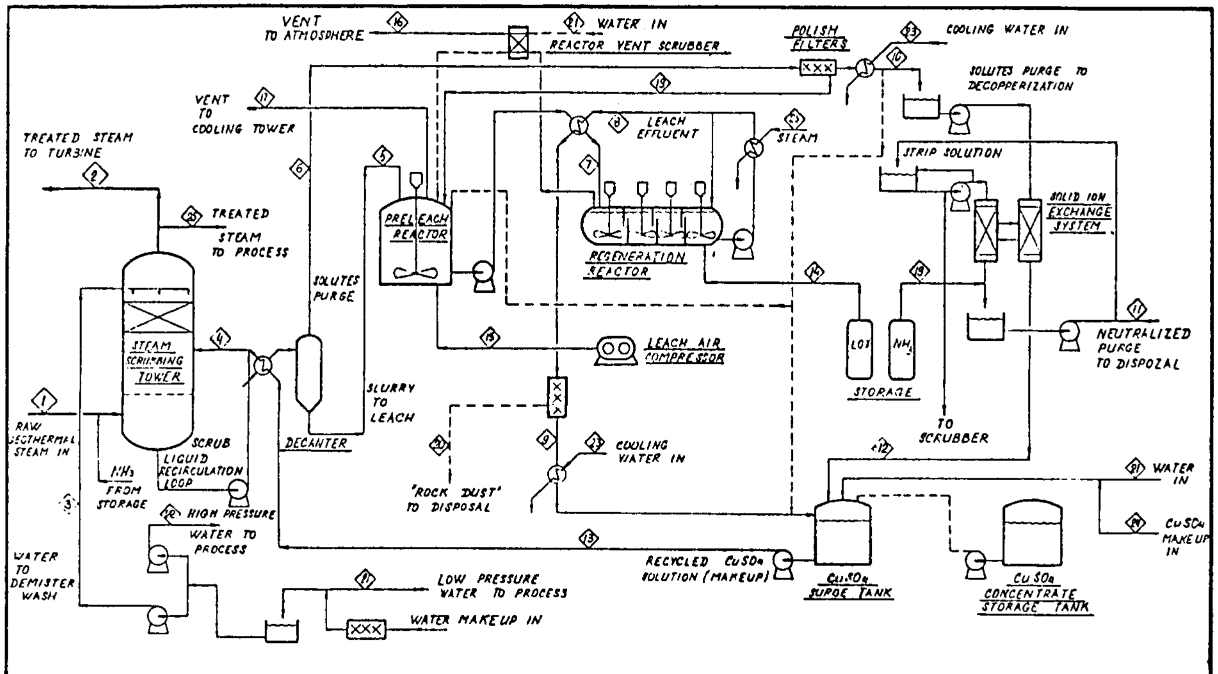


Fig. 1. Steam NH_3/H_2S ratio as a function of H_2S content.



STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25				
TEMPERATURE °C	175	175	30	175	90	30	110	130	100	40	40	40	40	30	50	80	80	50	90	100	30	30	30	30	115				
PRESSURE BAR	3	9	9	9	3	3	9	10	3	3	9	2	11	11	3	1	1	11	2	2	3	11	3	1	9				
TOTAL FLOW L/MIN			83	4.3M	192	57	166	150	158	56	51	5	163						1	1	1	75	1.2M						
KG/HR	500M	500M																							2.2M				
NCMH														125	450	10	900	31											
SOLIDS FLOW KG/HR				12.3M	370	0.1	205	0.05											0.1	0.05				5					

EIC CORPORATION

THE EIC PROCESS FOR REMOVAL OF HYDROGEN SULFIDE FROM GEOTHERMAL STEAM. UPSTREAM OF THE TURBINE

PROCESS FLOW DIAGRAM
OPTION A
REGENERATION WITH OXYGEN

Fig. 2. Process schematic and material balance - The Geysers average case.

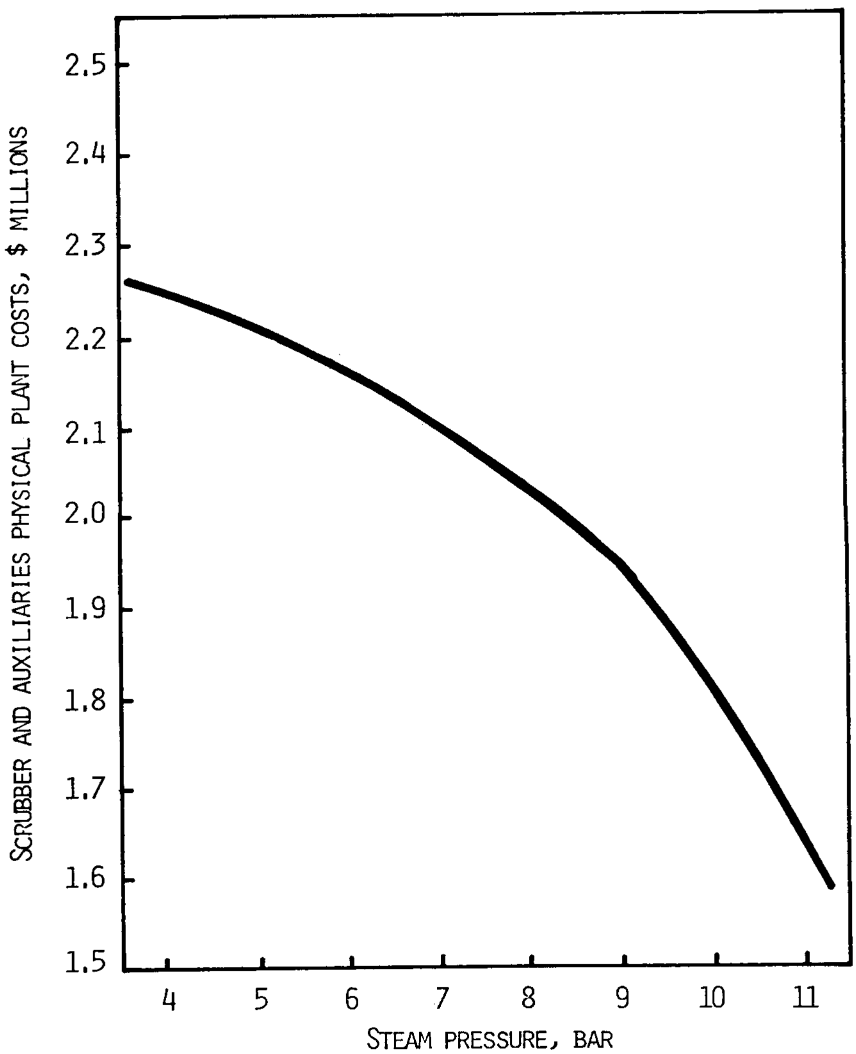


Fig. 3. Cost of scrubber and auxiliaries as a function of steam pressure for a 55 MW plant.

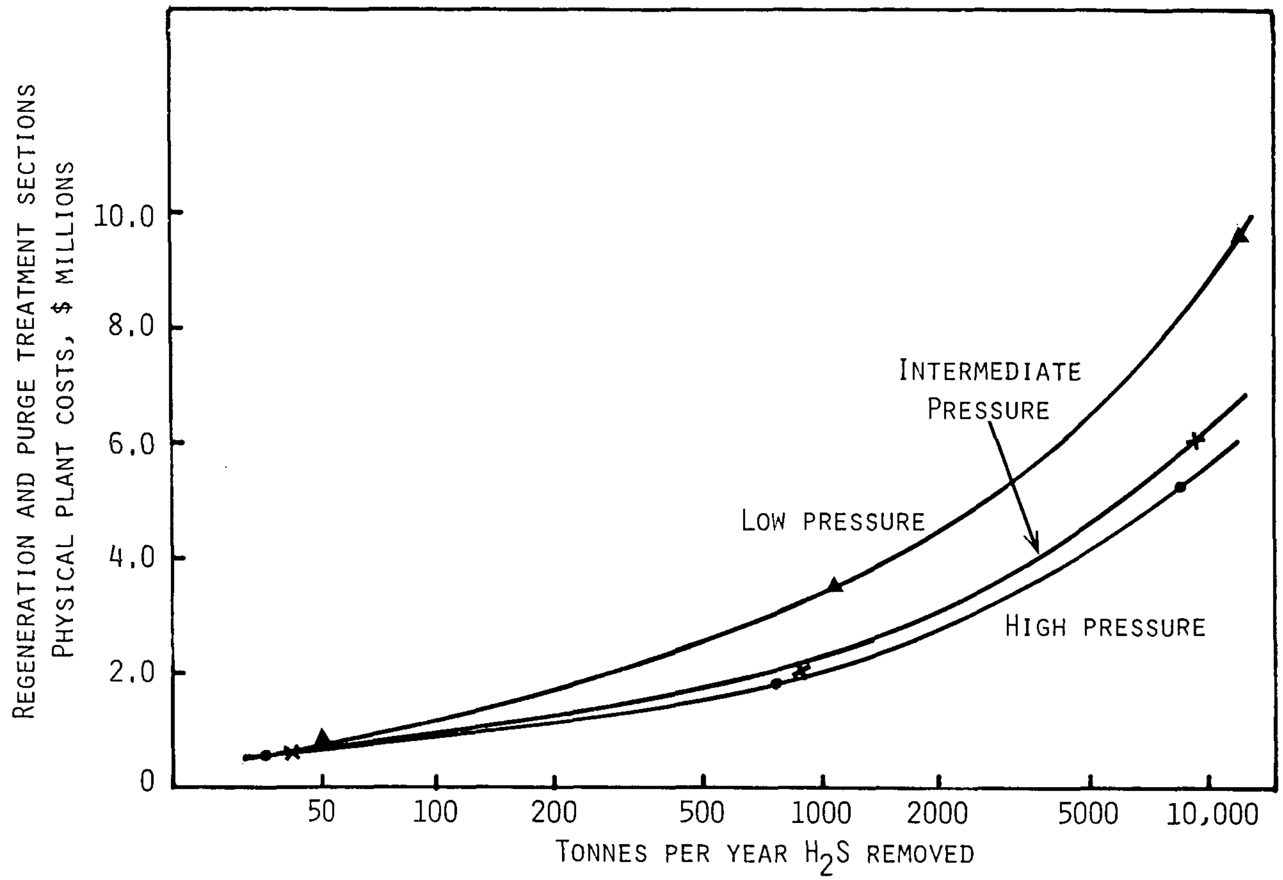


Fig. 4. Cost of regeneration and purge treatment sections as a function of steam pressure and amount of H_2S removed.

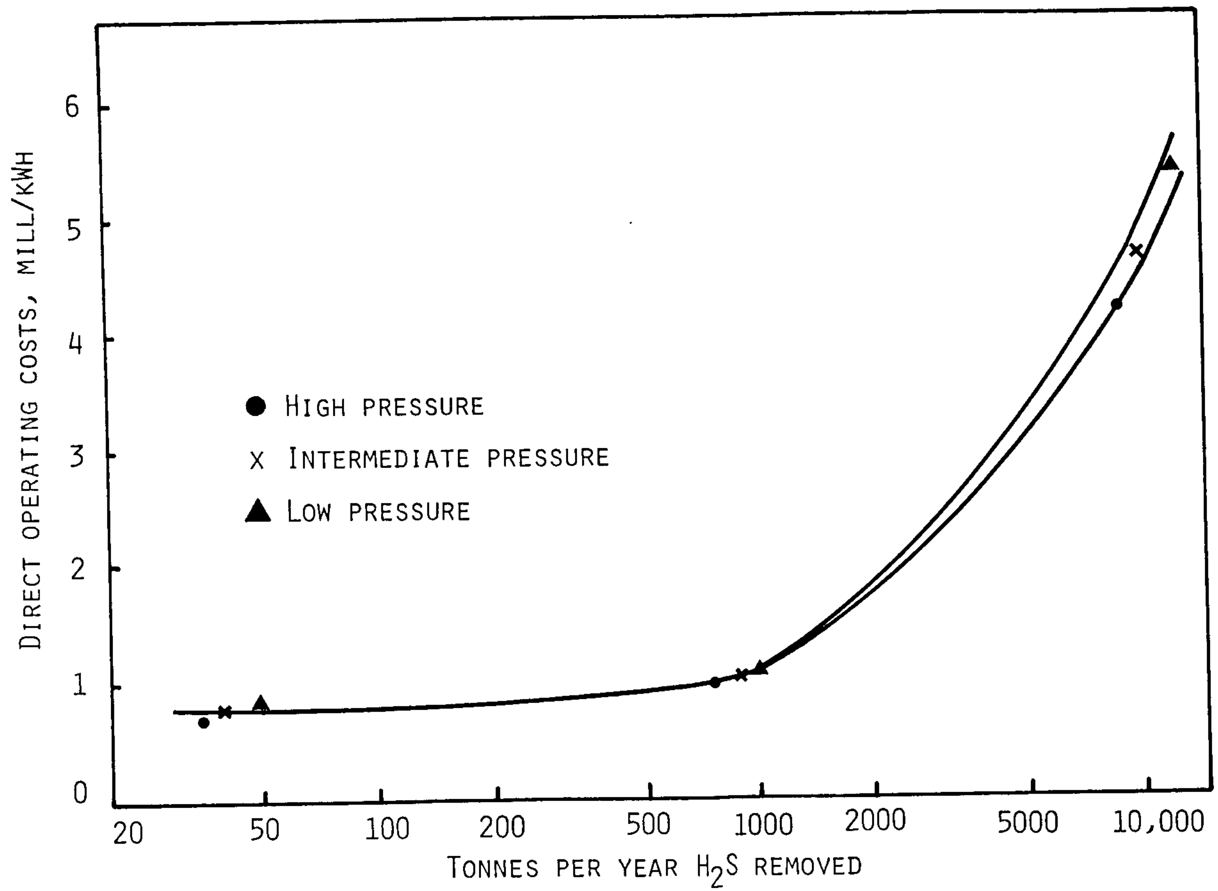


Fig. 5. Direct operating costs as a function of steam pressure and amount of H_2S removed.

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[e]	71,0[e]	0	170
Scrub Solution:							
g/ℓ 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	88-93.5	25-98.1	99
Percent S° Formation	1.6-39	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.

Table 2

SUMMARY OF RESULTS - REGENERATION RATE TESTS[a]

Solids Produced from Run[d]	314	328	404	416	524
Time, mins, to obtain:[b]					
50% Regeneration	120 (90)[c]	38	15	40	51
90% Regeneration	340 (160)[c]	80 (70)[c]	27	65	97
99% Regeneration	500 (200)[c]	125 (90)[c]	75 (36)[c]	80	125

[a]All regeneration tests carried out at 130°C, P_{O_2} = 3.4 bars.

[b]From smoothed data; log $(1-(1-x)^{1/3})$ vs. log (time).

[c]Extrapolated from initial rate data.

[d]See Table 5-1 for average conditions during scrubbing run.

Table 3

CASES CONSIDERED IN THE ECONOMIC EVALUATION

Case Name	Steam Pressure Bar	Steam Composition, ppm H_2S	Steam Composition, ppm NH_3	Steam Flow kg/hr[a]	Regeneration Option	Percent H_2S[b] Removal	Lab Run[c]	Comments
High pressure, high H_2S	11	2500	25-250	430,000	Oxygen	99.7	314	
High pressure, intermediate H_2S	11	230	170	430,000	Oxygen	97.2	314	
High pressure, low H_2S	11	10	10	430,000	Air	36	314	Lowest H_2S flow.
Intermediate pressure, high H_2S	9	2500	25-250	500,000	Oxygen	99.8	411,416,524	
Intermediate pressure, intermediate H_2S	9	230	170	500,000	Oxygen	97.5	411,416,524	Geysers Average Condition.
Intermediate pressure, low H_2S	9	10	10	500,000	Air	45	411,416,524	
Low pressure, high H_2S	4	2500	25-250	615,000	Oxygen	99.8	404	Highest H_2S flow.
Low pressure, intermediate H_2S	4	230	170	615,000	Oxygen	98.0	404	
Low pressure, low H_2S	4	10	10	615,000	Air	55	404	

[a] For the generation of 55 MW.

[b] To achieve emissions less than 50 gm/hr/MW.

[c] Runs from which supporting data were used to fix process conditions.

AN EVALUATION OF THE AVAILABLE ENERGY POTENTIAL OF THE GULF COAST GEOPRESSURED ZONES

EPRI RP1272

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Introduction The geopressured zones presently under serious study in the U.S. are tertiary sediments in the Gulf Coastal basin which are water saturated and exhibit pressures significantly greater than hydrostatic. These sediments are primarily shale, interbedded with sandstone. The top of the geopressured zone is frequently near 10,000 ft. or so, and extends to indeterminate depths. The water contained in these zones is at a moderately elevated temperature and, more significantly, appears to contain dissolved methane at near-saturation values. Conceptually, wells drilled into the geopressured zone might be expected to produce water without pumping, due to the high pressures. The dissolved methane could then be separated at the surface and used conventionally as natural gas. The water may contain sufficient heat to provide a useful source of geothermal energy, and the hydraulic energy might also provide useful work.

Development of the geopressured/geothermal resource is largely dependent upon production characteristics of geopressured reservoirs. These in turn are intimately related to properties of the formations, and can be defined within reasonable limits.

Characteristics of Gulf Coast Sediments The Gulf Coast basin, from tertiary times to the present, has represented conditions which are generally similar to those existing along the Coast today. The land is in a continual state of subsidence and sediments brought into the Gulf of Mexico by the major river systems are worked and reworked by long-shore currents into a series of coastal sandbars and barrier islands in an environment of which the present Texas Coast is thought to be a model. This normal pattern of subsidence has been accompanied by periods of high deposition similar to that occurring in the Mississippi Delta today. The bars and islands were covered by new layers of clastic sediments while the edge of the basin further subsided under the enormous weight, and large growth fault systems formed near the down-dip edge of these deposits. The subsurface sandstones which became the basis for the deep aquifer systems are the remnants of the ancient sandbars and the stream channels of the deltaic environment.

When sections of these sandstone deposits are isolated within a shale envelope, geopressures are believed to result. Bruce[1], for instance, has provided an excellent description of this depositional environment and of the role of growth faults in the formation of geopressured sediments. The depositional style of the tertiary strata along the Texas Gulf Coast as described by Bruce is shown in Figure 1.

Energy Contained in the Geopressured Zones Speculation about the geopressured sediments has resulted in a number of estimates of the energy they might contain. The most comprehensive of these estimates is the result of work performed by the U.S. Geological Survey. The most recent of the USGS reports, by Wallace et al. [2], has defined the resource base summarized in Table I. The total estimated contained methane, 59,700 trillion cu.ft. (TCF), is a value nearly thirty times higher than the total known natural gas reserves in the United States. The estimate of 101,400 quads of thermal energy would make the geopressured zone the largest single known geothermal resource in the United States.

However, it is important to understand the assumptions Wallace made in arriving at these estimates, and to place the numbers in perspective.

Generalized Gulf-Coast Model Gulf Coast sediments may be considered to be completely saturated with water; that is, the water table is near the surface everywhere along the coast, and extends to indeterminate depth within the pore space of individual rock formations. Wallace first made estimates of the total water contained in the rocks of interest based on assumed values of porosity. This total contained-water then became the basis for the

Table I. Energy-in-Place Estimates, USGS Circ. 790 (Wallace et al, 1978)

		Methane (10^{12} SCF)			Thermal (10^{15} BTU)		
Location	Area mi^2	Sand	Shale	Total	Sand	Shale	Total
Total, onshore & offshore	120,000	5,700	54,000	59,700	10,430	91,000	101,400
Onshore only	70,000	3,052	35,100	38,152	5,490	57,000	62,490

estimated resource base.

Contained Methane Hydrocarbons are slightly soluble in water, and methane is the most soluble of all. Studies have indicated that oil-field type brines in the Gulf Coast generally contain dissolved methane. The actual degree of solubility is dependent upon temperature and pressure and, consequently, the water in the geopressured zones should contain an abnormally large amount of dissolved methane. Wallace estimated the temperature and pressure throughout the geopressured regime, and assumed the water was saturated with methane under these conditions. Although the data base on which this assumption was made is very limited, the data are consistent, and tend to be verified by recent work. The saturation values of methane in geopressured brines appear to be in the range of 20 to 40 SCF per barrel of water.

Thermal Energy The estimate of the contained thermal energy was based on the total heat content of the water above 15°C, although this is a temperature much lower than any practical utilization temperature for the brine. Temperatures in the geopressured zone range from less than 100°C to more than 200°C, but reservoir quality sands seldom exhibit temperatures as high as 150°C.

Sand and Shale On the basis of a regional study of over 3,000 well logs, Wallace estimated that of the total resource base, about 10% was contained in sandstones, the remainder in shale. Since there is no foreseeable prospect of recovering any useful energy from Gulf Coast shales, a much more meaningful view of the resource is the estimate of the energy in the sands, also given in Table I. This estimate cuts the useful resource by about one order of magnitude.

Recoverable Energy The amount of energy recoverable from the resource base (without regard to cost) is dependent upon the total volume of fluid which can be produced from production wells. Since the only practical production technique consists of flowing the wells and depleting the reservoir pressure, recoverable energy is predictable from reservoir parameters. Randolph [3] has shown that production from a geopressured well utilizing a range of realistic Gulf Coast reservoir parameters will range from less than 1% to a maximum of about 4% of the total contained energy (most of the fluid, as well as the dissolved gas, will remain in the formation after the pressure is depleted). Using the more optimistic of these numbers, the recoverable energy from Wallace's resource base would amount to a maximum of about 228 TCF methane and 420 quads thermal, of which roughly 40% would lie offshore.

These are still sizeable numbers, if even a moderate fraction of the latter values can ultimately be recovered.

Basis for Exploitation of Geopressure Geopressured production wells must be capable of certain minimum performance to produce energy at a cost competitive with other energy sources, even in the relatively distant future. First, the wells would have to be drilled and completed in a productive sandstone at reasonable cost. Next, the flow of hot water would have to be substantial, and to last for an extended period of time to amortize the investment. Finally, the energy separated from the water would be required to provide sufficient revenue to pay the operating expense including spent brine disposal, amortization of the investment, and an adequate rate of return to justify the risk. The reservoir characteristics which would be required to provide such performance have been the subject of a number of recent investigations.[3-6] In general, the conclusions of these studies indicate that flow rates in the range of at least 40,000 bbl/day or more continuously for 20 years or so would be required to compete with the current cost of fuel (\$2-\$3/10^6BTU). Flow rates averaging only 10,000 bbl/day for 20 years or so might yield energy at costs in the range of \$8/10^6BTU, a cost which conceivably could be of importance in the future. Energy costs above \$10/million BTU (in 1980 dollars) are probably beyond the realm of current interest.

Reservoir Parameters The capability of a geopressured reservoir to produce fluid depends upon a combination of formation parameters, principal among which are porosity, permeability, formation thickness, compressibility and drainage volume. In general, quasi steady-state reservoir equations are adequate to predict the performance of geopressured water reservoirs.[7,8] Samuels [9] gives an excellent discussion of the reservoir aspects of geopressured fluid production and, summarizing previous work, shows that the performance of a geopressured well can be described by an equation of the form

$$P_s = (P_r - P_h - P_f) - \left(\frac{5.615Qt}{\pi r_e^2 h\phi C_e}\right) - \left(\frac{Q \cdot \mu}{7.08kh}\right)\left\{\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right]\right\}$$

where

- Q - Flow in bbl/day
- k - Permeability in Darcies
- h - Thickness in feet
- t - Time in days
- ϕ - Porosity, fraction
- μ - Viscosity centipoise
- C_e - Compressibility
- r_w - Radius of the well in feet
- P_r - Initial pressure in reservoir
- P_s - Pressure at the surface
- P_h - Pressure due to the hydrostatic head
- P_f - Friction loss due to flow up the pipe

Examination of this equation reveals that the flow rate, Q, is largely dependent upon the pressure and the permeability-thickness product, kh, while the pressure behavior with time (duration of flow) is mainly a function of the volume of fluid present, $\pi r_e^2 h\phi$, and the formation compressibility.

Samuels has given a graphic summary of reservoir behavior as a function of reservoir size and permeability. His representation is reproduced in Figure 2. Here it can be noted that for a sand 200 ft. thick, the minimum reservoir permeability that will yield an extended flow rate of 40,000 bbl/day is 10 mD. For a well to flow for as long as 20 years at this 40,000 bbl/day rate would require a minimum reservoir radius of about 8 miles (200 sq. mi. area) regardless of the permeability.

Probable Reservoir Characteristics A considerable amount of study of the formation parameters of potential geopressured reservoirs has been performed over the past several years, based on an enormous volume of data generated by more than 300,000 petroleum wells drilled in the Gulf Coast over the past 50 years. The results of these studies have produced a reasonably consistent picture of the range of values likely to be encountered in the production of geopressured water sands.

Porosity The subsurface sandstone deposits represent the only useable reservoirs for either petroleum or geothermal reservoirs, since shale is virtually impermeable. The initial porosity of Gulf Coast sands is about 40 to 45% and as subsidence and burial occur, this value is continuously reduced by compaction and cementation. Reduction in porosity with depth on the Gulf Coast as found by Loucks et al. [10] is summarized in Figure 3. The reduction typically amounts to 1.25 porosity-percent or so per 1,000 ft. of depth. The range of porosity values found in "good" geopressured water sands is from 10% or so in the South Texas Vicksburg formation, to 30% or more in the best prospects in South Louisiana. An average value for many prospective areas is about 20%. Porosity of geopressured sands is important primarily because of its effect on permeability, a crucial production parameter.

Permeability The permeability of Gulf Coast sandstones, although not a direct function of porosity, is closely related. As porosity is reduced, permeability tends to suffer drastically. In-situ permeability is known to exhibit a log-normal distribution over any particular depth interval, and while there may be individual sandstone elements exhibiting high permeability even at depth, over an extended depth interval average permeability cannot be expected to depart drastically from the statistical mean. This fact is graphically portrayed by Loucks in Figure 4. Permeability frequently is shown to decline about one order of magnitude for each two to three thousand feet of depth. Swanson et al. [11] have shown that of a large number of deep geopressured gas sands studied in South Texas, none exhibited in-situ permeability as great as 10 mD, while the average was only about 1 mD. In South Louisiana, measured permeability values range over several orders of magnitude. Average values in good, potentially productive zones may vary from 100 mD at the top of geopressure near 10,000 feet, to 10 mD at 13,000 feet, and 1 mD at 16,000 feet.

Reservoir Volume Individual geopressured reservoirs are formed from sandstone deposits which have undergone considerable modification in the process of burial to great depth. Faulting is common, and individual sand bodies tend to be relatively small. Doscher et al. [12] summarize previous work on the size of Gulf Coast petroleum reservoirs and conclude that the volume of potential geothermal reservoirs in the geopressured zone is likely to be no more than 0.3 to 1.5 cu. miles. Of the 103 largest petroleum reservoirs known in the offshore U. S. Gulf Coast, they report only three with an area as large as 8 sq. miles, and a maximum reservoir volume of only 0.05 cu. miles. While the size and volume of petroleum reservoirs may not be indicative of the size and volume of geopressured aquifers, it is consistent with the origin of the sandstone deposits and the complex faulting characteristic of the Gulf Coast.

The single-well drainage volume is probably the most serious unknown in accurate assessment of the geopressure/geothermal resource.

Probable Performance of Geopressured Reservoirs Based on the reservoir equations discussed previously, it is possible to make a probability analysis and predict the performance of geothermal wells under a range of conditions.

Such a probability analysis, utilizing a Monte Carlo routine, has been applied to a number of known geopressured prospects in the Gulf Coast, the locations of which are shown in Figure 5. In such a procedure, minimum, maximum and most likely values are assigned to the 9 stochastic reservoir parameters. Then by an iterative process, calculations of flow rate are made and a probability distribution plotted. The results of such an analysis for the S.E. Pecan Island prospect in Louisiana are shown in Figure 6. This prospect, one of several described by Bernard [13] in an assessment study of Louisiana geopressured zones, is particularly interesting because of its large sand volume and extensive overall area (67 square miles). Laminated shale and sand occur from 13,500 feet to 17,500 feet, with a total estimated sand volume of 9 cubic miles. Geologically, it represents a destructive delta of unusually large size, although the individual reservoirs are undoubtedly segmented by faulting and other depositional features. A considerable amount of conventional gas production in this vicinity also makes it possible to estimate reservoir parameters with reasonable assurance. The principal unknown in S.E. Pecan Island is the single-well drainage area.

The probability analysis shows that wells drilled in this prospect have a 60% probability of flowing at 14,000 bbl/day for twenty years, and a 10% probability of flowing at 50,000 bbl/day. The average of all values is 22,172 bbl/day.

Selecting parameters representative of the best part of the reservoir (net sand thickness of 980 feet), and assuming an optimistic single well drainage area of 13 sq. miles, the "best" well in the prospect should perform as shown in Figure 7. The parameters used in this analysis are given in Table II. This well should flow at a rate of 50,000 bbl/day for 11-1/2 years, at which time surface pressure should be depleted to 300 psi. After that time, the production rate will continually decline as shown in the figure. At the end of twenty years the well will still be flowing at a rate of nearly 20,000 bbl/day. After 20 years, the well will have produced more than 30 million barrels of water and 10 billion cubic feet of natural gas.

It must be pointed out that this performance represents a highly optimistic case, in one of the most promising geopressured prospects known. The assumed dissolved methane, 35 SCF/bbl, is higher than any actually produced by test results to date. The assumed permeability-thickness product, 9800 mD-ft., is very high. One can be relatively assured that of all the resource base estimated by Wallace, only a small fraction can be contained in reservoirs with this quality.

Table II. Reservoir and Well Parameters, Single Well Development, S.E. Pecan Island, LA Prospect, Optimistic Drainage Area

Well Depth	17,500 feet
Average Production Depth	15,800 feet
Average Reservoir Pressure	13,500 psi
Average Hydrostatic Pressure	7,350 psi
Surface Pressure (minimum)	300 psi
Average Fluid Temperature at Surface	290°F
Well (production tubing) Diameter	0.46 feet (5-1/2"OD)
Drainage Area	13 mi^2 (8400 acres)
porosity	23%
permeability	10 mD
Compression Drive Coefficient	5×10^{-6} psi^{-1}
effective sand thickness	980 feet
dissolved methane	35 SCF/bbl
Initial Production Rate	50,000 bbl/day

Economics Assuming a production well with the characteristics of the optimistic S.E. Pecan Island well just described, the economics of production can be established based on the cost of the installation, the operating costs, and value of the energy produced. In preparing the economic analysis, the methodology of by-product costing was used as described by Bloomster and Knutson.[14] Natural gas is considered the primary product. Electric energy and thermal energy for direct use applications are regarded as saleable byproducts. The production cost of natural gas includes the capital and operating costs of production and injection wells, their interconnecting piping, other well field equipment, and the equipment necessary to separate natural gas from brine and process the gas to pipeline standards.

Under the byproduct methodology, the value of the thermal and hydraulic energy in the brine used for electric energy production is based only on the incremental equipment required to generate the electric energy. For cases where the electric energy production cost estimates are less than that typical for new conventional generating units in the Texas and Louisiana region, the difference is credited to the natural gas, thus reducing its cost.

Capital cost estimates for a S.E. Pecan Island well and production facilities are shown in Table III. (The well cost is consistent with natural gas practice in the area, and consequently is optimistic.)

Capital costs for the natural gas processing facilities in conjunction with a binary cycle geothermal power plant are shown in Table IV (power plant cost not included). Utilizing an operating and maintenance expense of 2% of the capital cost, the estimated production cost of natural gas from this facility is $5.14/MCF.

Table III. Capital Cost Estimate for Production Well and Injection Wellfield, S.E. Pecan Island, LA Prospect ($1,000)

Land Lease and Development	800
Geophysics and Geology	300
Production Well	5,000
Piping to Energy Recovery Processes	20
Injection Wells	2,000
Piping to Injection Wells	1,580
Home Office Services	230
Permits and Environmental	250
Contingency	1,520
Estimated Construction Cost	11,700
AFDC and Other Owner's Costs	1,300
Total Capital Cost	13,000

Table IV. Capital Cost Estimates-Natural Gas Separation and Processing Facilities ($1,000)

Location - S.E. Pecan Island

Power Plant	Binary
Mechanical Equipment	969
Electrical	100
Civil/Structural	110
Piping	290
Instrumentation	160
Yardwork & Miscellaneous	20
Direct Field Cost	1,649
Indirect Field Cost	254
Total Field Cost	1,903
Home Office Services	267
Contingency	326
Estimated Total Construction Cost	2,496
AFDC and Other Owners' Costs	369
Total Capital Cost	2,865
Estimated Gas Production Cost	$5.14/MCF

Electric Power Generation Electric power can be generated by means of a binary cycle or flashed steam geothermal plant utilizing the by-product brine as a heat source. A hydraulic turbine-generator unit can also be installed at the wellhead to generate power, utilizing the excess pressure at the wellhead, although the output would continually decline as the pressure is depleted. Capital cost estimates for a single well binary power plant show a total investment of $3.4 million for a 1.6 Mw(e) (net) binary cycle plant and $680,000 for a 1.5 Mw(e) (net) installation of high and low pressure turbines. The cost of electric power from the thermal plant is estimated at 43 mills/kwh and for the two hydraulic turbine generators, 3.4 mills/kwh for the high pressure unit and 8 mills/kwh for the low pressure unit. These costs are based on an 11.4% rate of return, which is typical for electric utility companies in the Texas and Louisiana region.

Conclusions While the resource base estimated for the Gulf Coast geopressured zones is extremely high, most of the resource is apparently contained in shale, for which there is no production technology known. Of the remaining resource contained in sandstone, only a small percentage is likely to be encountered in reservoir-quality formations capable of high-volume flow for sustained periods of time. The minimum cost under the most optimistic conditions and in the most favorable known prospects is upwards of $5/mcf for natural gas, 43 mills/kwh for thermal generated electric power and about 9¢/kwh for power generated by hydraulic turbines. Under these very favorable reservoir conditions, a small amount of marginally profitable energy may be produced. The number of such high-quality reservoirs depends primarily upon the size distribution of large, connected sand bodies in the geopressured zone. While this is presently indeterminate, the probability is strong that such very large, permeable reservoirs will be few in number, difficult to locate and expensive to produce. The strongest factor in the economic success of a large high quality production reservoir, will be the amount of dissolved methane it contains. If the actual value of dissolved gas is substantially less than 35 SCF/bbl, the cost of production in S.E. Pecan Island will increase almost directly. A value of 20 SCF/bbl would raise the cost of the gas to about $9/MCF.

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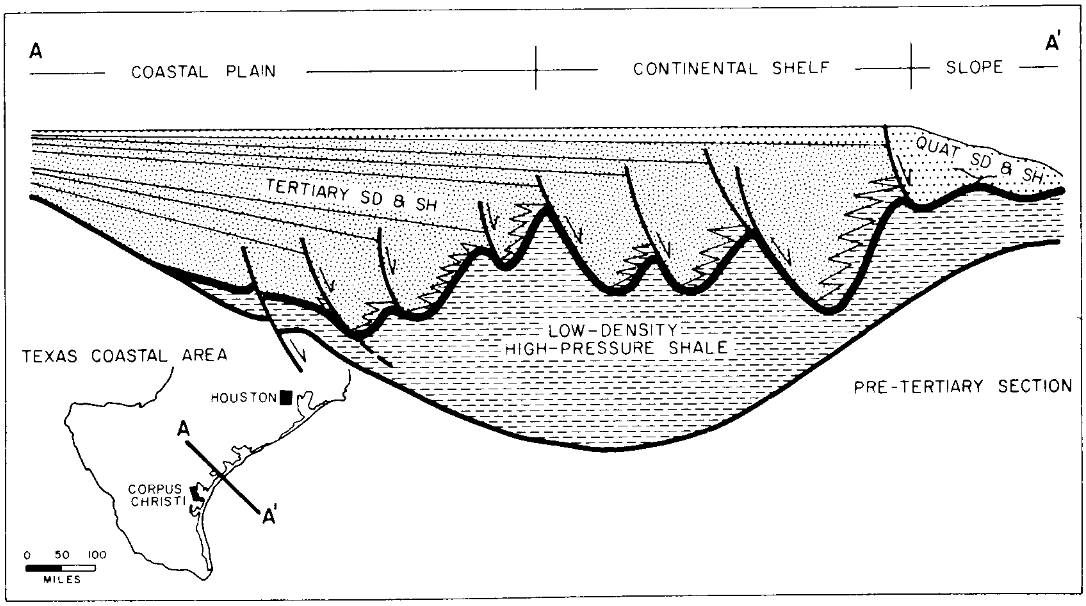

Figure 1. Depositional Style of Tertiary Strata Along the Texas Gulf Coast (Bruce, 1973).

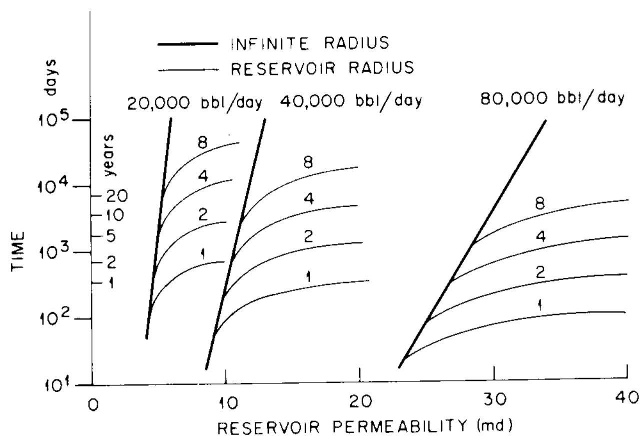

Figure 2. Well Life as a Function of Permeability, Flow Rate, and Reservoir Radius for a Well Diameter of 6 in., Reservoir Thickness of 200 ft, and Pore Compressibility of 7×10^{-6} psi^{-1}. All Radii Are Given in Miles. (From Ref. 9)

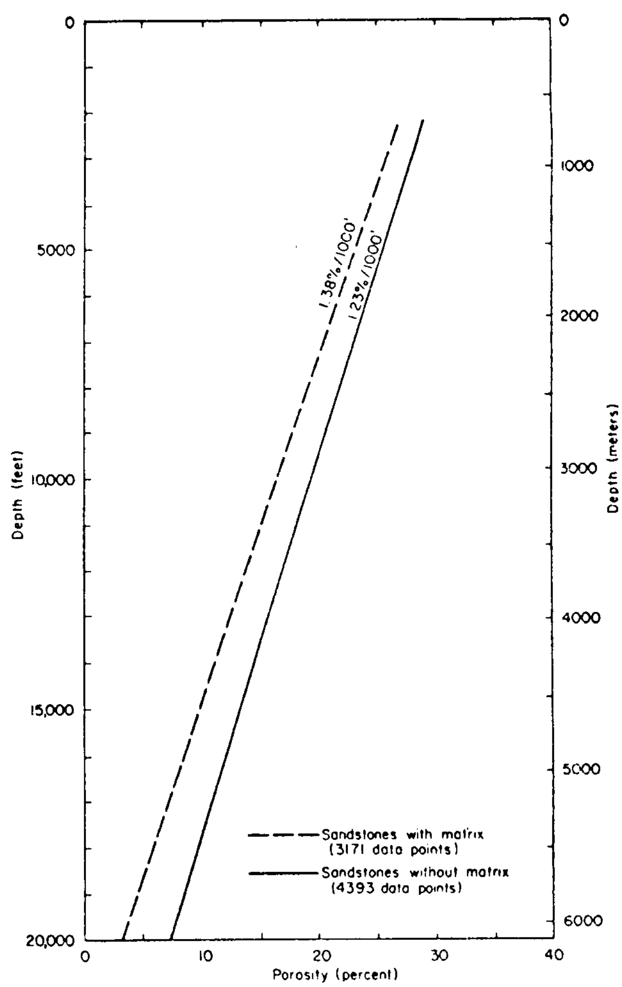

Figure 3. Mean Porosity Versus Depth for Lower Tertiary Sandstones with and Without Clay Matrix from Along the Texas Gulf Coast. (From Ref. 10)

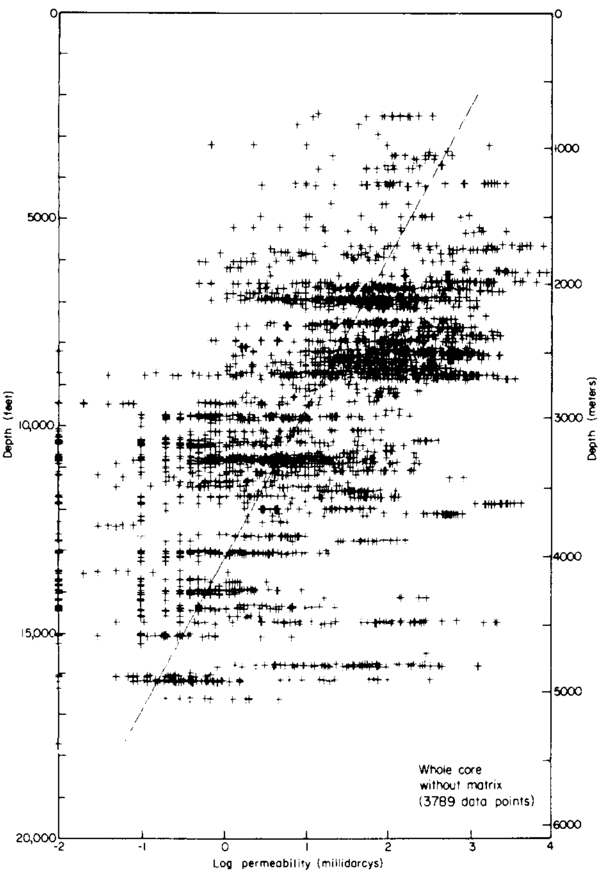

Figure 4. Permeability Versus Depth from Whole Core Analyses for Lower Tertiary Formations Along the Texas Gulf Coast. (From Ref. 10)

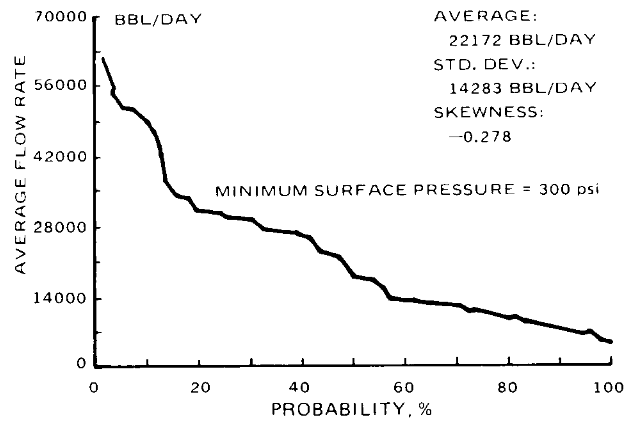

Figure 6. Probable Average Flow Over a Twenty Year Period for a Well in S.E. Pecan Island Prospect, Vermillion Parish, LA.

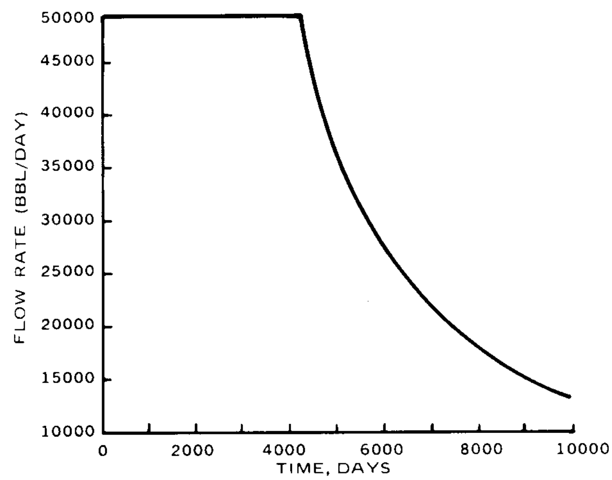

Figure 7. Flow Rate Versus Time, Single Well Development, S. E. Pecan Island, LA., Optimistic Reservoir Parameters, in Most Favorable Part of the Reservoir.

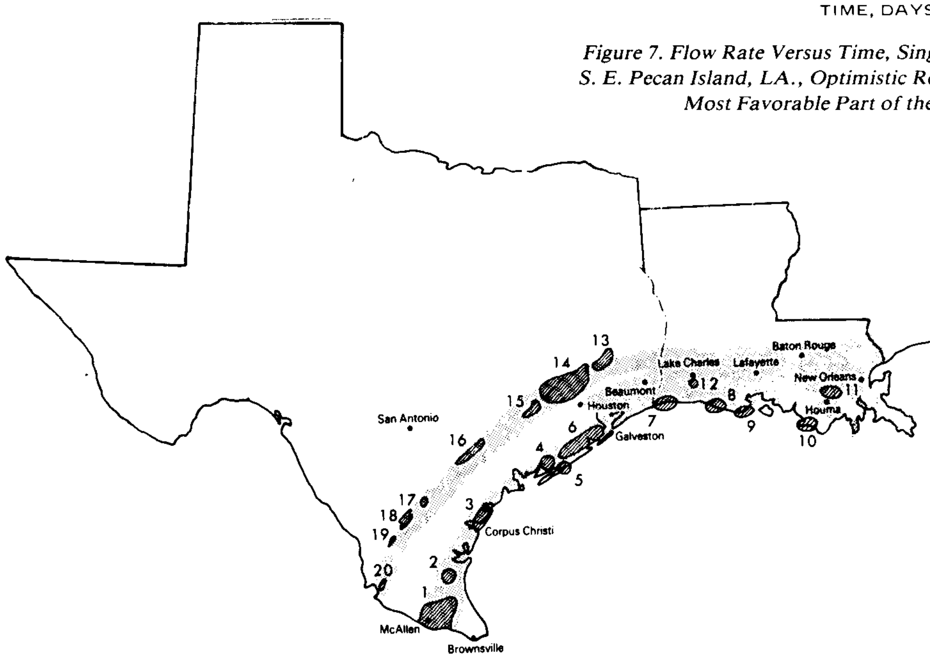

Figure 5. General Areas of Geopressured Sand Development, and Known Geopressured Prospects Which Have Received Detailed Study.

PERFORMANCE ASSESSMENT OF FLASHED STEAM GEOTHERMAL POWER PLANT

RP1195-1

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Introduction Five years of operating experience at the Comisión Federal de Electricidad Cerro Prieto flashed steam geothermal power plant are evaluated from the perspective of U. S. utility operations. We focus on the design and maintenance of the power plant that led to the achievement of high plant capacity factors for Units No. 1 and 2 since commercial operation began in 1973. For this study, plant capacity factor is the ratio of the average load on the machines or equipment for the period of time considered to the capacity rating of the machines or equipment.

The plant capacity factor is the annual gross output in GWh compared to 657 GWh (2 x 37.5 MW x 8760 h). The following table shows the annual output and PCF for the years 1974-1978.

YEAR	GWH	FACTOR
1974	463	0.70
1975	518	0.79
1976	579	0.88
1977	592	0.90
1978	598	0.91

The CFE operates Cerro Prieto at base load consistent with the system connected electrical demand of the Baja California Division. The plant output was curtailed during the winter months of 1973-1975 when the system electric demand was less than the combined output capability of Cerro Prieto and the fossil fuel plant near Tijuana. Each year the system electric demand has increased and the Cerro Prieto units now operate at full load all the time.

The CFE added Units 3 and 4 to Cerro Prieto in 1979 which increased the plant name plate capacity to 150 MW. Part of this additional capacity will supply power to San Diego Gas and Electric Company through an interconnection across the border.

The achievement of a high capacity factor over an extensive operating period was influenced by operation, design, and maintenance of the geothermal flash steam power plant.

Geothermal Power Plant Operation The operation of a geothermal steam electric plant is relatively simple compared to a fossil fuel steam electric plant. A flow diagram for the steam cycle of a geothermal plant is shown in Figure No. 1. The equipment for either plant is similar, e.g., steam piping, turbo-generator, circulating water system, cooling tower, air-ejectors, and condenser. The operation of this equipment is known to many electric utility plant personnel, but the fossil fuel steam plant problems involving fuel handling, ash handling, combustion, and feedwater systems are absent in the geothermal facility. Multiple wells supplying steam to the geothermal plant are an advantage compared to a single boiler steam supply in the fossil fuel plant in many respects.

The flash steam geothermal plant and the hydro-electric plant appear similar in their manner of operation. Both types of plant conduct the working fluid through the prime mover turbine; both obtain an energy supply from a large reservoir; both base load the generating units consistent with system electrical demand and reservoir ability to supply input energy. The operation of the geothermal plant can be compared to the hydro-electric plant for manning requirements and plant capacity factor goals.

Geothermal Power Plant Design Figure No. 2 shows the basic design for the Cerro Prieto geothermal units. Most of the equipment arrangement is familiar to steam electric power plant personnel.

The direct contact barometric condenser is unique for geothermal steam plants. Usually, the condenser is a closed surface type heat exchanger that returns condensate to the boiler plant. Cooling water does not have direct contact with the steam exhaust from the turbine.

In the direct contact barometric condenser, the turbine exhaust steam is condensed by direct mixture with the cooling water flow. Direct contact of the cooling water and exhaust steam gives optimum condenser heat transfer. The combined liquid flows to the cooling tower for heat rejection; a portion of the flow is discharged to evaporation ponds to maintain the desired water quality in the cooling tower basin.

Three steam jet air ejectors are installed in each unit to remove non-condensable gases from the condenser. Usually only two air ejectors are required to handle the non-condensable gas flow. The spare ejector has been helpful when it was necessary to remove an ejector from service for maintenance while the generating unit continued in service.

Materials of Construction, Design One thousand tests were conducted on a number of candidate materials prior to the selection of materials for the critical parts of the plant. Samples were exposed to the geothermal steam, both aerated and non-aerated and to condensate, for a period of 150 days. The steam was obtained from Cerro Prieto well M-8 and the condensate from steam from wells M-3 and M-5.

The material for equipment fabrication was selected on recommendations of the manufacturers plus CFE candidate material tests. Operating experience has confirmed that most of the material selection was correct.

There have been some corrosion problems with the metal alloys supplied by the manufacturers. Before discussing the material modifications that required outages or impaired the achievement of high capacity factor, we will describe some of the power plant equipment.

Power Plant Equipment, Turbine Generator The turbine generators were supplied by the Toyko Shibaura Electric Company, Ltd. (Toshiba). The steam turbines are of the single-cylinder, double-flow type with six stages of impulse-reaction blades in each flow path. The generator is rated at 44,200 kVA, 13.8 kV, 60 hz, and a power factor of 0.85. The speed of rotation is 3600 RPM, and both the rotor and the stator are hydrogen cooled.

The turbine rotor is machined from a 1 Cr-1 Mo-1/4 V alloy steel forging, and forms a shaft, wheels, bearing journals and coupling flanges. Alloy steels containing Ni are not used because of their poor corrosion resistance. The turbine blades are machined from 12 Cr alloy steel bar stock; they are enclosed with a shroud which is hand-riveted in place. The blades of the last row are fitted with stellite erosion shields and fastened together with lashing wire to minimize vibrations. The nozzle partitions are of 12 Cr-0.2 Al alloy steel, and the labyrinth strips are of 15 Cr-1.7 Mo alloy steel. The turbine outer and inner casing are made of carbon steel according to ASTM specification ASTM-A285.

Power Plant Equipment, Barmometric Condenser The condenser is a direct-contact barometric type located adjacent to the power house as shown in Figure No. 2. The exhaust from the turbine is conveyed to the condenser by means of a duct which is 3.6 m (11.8 ft) in diameter and about 40 M (131 ft) in length, including three right-angle bends. Non-condensable gases are removed from the top of the condenser shell through a 0.7 m (2.3 ft) diameter pipe.

The shell of the condenser is carbon steel with an interior protective coating of epoxy resin. Circulating water is distributed across the exhaust vapor inlet by means of nozzles and trays made of Stainless Steel AISI 304L. The condenser is 25.35 m (83.2 ft) high with a shell diameter of 6.7 m (22 ft), shell height of 9.6 M (31.5 ft), and tail pipe 2 m (6.6. ft) in diameter and 12 m (39.4 ft) in length. Condensers are shown in Figure No. 3.

Power Plant Equipment, Non-Condensable Gas Extraction The gas extraction system consists of a two-stage steam ejector with an inter- and after-condenser. There are three first-stage steam ejector nozzles that operate in parallel, each is connected to a separate inter-condenser. There are three second-state steam ejectors, also in parallel, and three-after-condensers. The gas extraction system receives motive steam from the main steam line and cooling water from the circulating water system.

The non-condensable gases removed from the condenser by means of the steam ejector system are discharged to the atmosphere through 475 mm (18 in) diameter fiberglass pipes (one for each unit) which extend to a height of 40 m (131 ft) above the ground. The prevailing winds blow these gases away from the plant. On windless days, the concentration of H_2S may reach dangerous levels in certain areas. An additional vent line was constructed from the power house at the base of the gas extraction stacks to the evaporation pond. The resin-lined, steel vent duct is 584 mm (23 in) in diameter and is 1250 m (4100 ft) in length.

H_2S is also emitted from the cooling tower stacks so it is impossible to vent all the H_2S away from the power house. The prevailing winds usually carry the cooling tower plumes away from the power house. The cooling tower is 100 m (328 ft) from the plant and is aligned with the direction of the prevailing winds.

Power Plant Equipment, Electrical Apparatus The electrical equipment is susceptible to corrosive attack by hydrogen sulfide; special precautions are taken for the protection of this equipment. Most switch-boards, including the control room main switch-board, are installed in enclosures provided with air conditioning systems. These a/c systems are fitted with activated carbon filters filled with activated alumina beads impregnated with potassium permanganate. The electrical contacts on the high-voltage side at the substation are plated with a noble metal alloy.

Unit Outages Operating records at the plant were reviewed to accumulate the annual forced and programmed outage hours. There were a total of 344 outage hours; from the time Units

No. 1 and 2 began commercial operation until the end of 1978. The small number of outage hours shows the good availability and reliability of the power plant equipment. The equipment performance was a result of careful design, material selection and maintenance.

The following table Outage Hours shows forced and programmed outages for Units No. 1 and 2. Forced outages are defined by the CFE as non-scheduled shutdowns initiated by electrical relay actions. Programmed outages are controlled unit shutdowns to correct a mechanical problem.

OUTAGE HOURS

Year	Unit	Forced	Programmed	Total
1974	1	9	12	21
1974	2	8	41	49
1975	1	29	20	49
1975	2	18	83	101
1976	1	2	35	37
1976	2	14	14	28
1977	1	-0-	22	22
1977	2	-0-	6	6
1978	1	-0-	7	7
1978	2	-0-	24	24

The programmed outages were necessary to make repairs of associated material damaged by corrosion. Oil coolers, hydrogen coolers and steam jet air ejectors were the items that experienced failures.

Power Plant Maintenance The turbine lubricating oil coolers were furnished with aluminum tubing. Corrosion of the tubing was severe and the CFE changed the tube material to titanium beginning in 1974. The electric generator hydrogen coolers were also furnished with aluminum tubing which had to be replaced with titanium.

The cooling water supply headers for the hydrogen coolers were furnished as stainless steel by the CFE. The supply and return piping, connecting the headers and coolers, was furnish by Toshiba as low carbon steel. This piping was replaced with stainless steel during programmed outages or annual maintenance.

The discharge (diffuser) tubes of the air ejectors were furnished as carbon steel. This material had to be replaced with stainless steel because of severe corrosion perforations caused by the non-condensable gases. The plant design had three sets of ejectors for each unit but the manifold shut-off valves for the ejectors failed to close and the unit had to be shutdown to do repairs on the ejector set.

Power Plant Maintenance Schedule Major maintenance was conducted on an annual basis per recommendations of the turbine manufacture, Toshiba. During the turbine internal annual inspections the CFE found scaling in the nozzles and on the blading of the turbine. The deposits were removed by mechanical cleaning and the turbine internals were examined with a dye penetrant test.

No fissures were detected in the turbine internals but the scaling continued to form during the running period. The scaling was caused by carry-over in the steam from vapor/liquid separators at the well heads. The scaling restricted steam flow and decreased the unit output about 10 percent during the course of one years operation.

The vapor/liquid separator is shown in Figure No. 4. The length of the internal vapor outlet pipe was increased and the separation improved. The better quality of steam was evident during the annual overhauls. The internal condition of the turbine showed less scaling relative to prior inspections. This internal condition prompted the CFE to extend the time between overhauls. The following table shows the maintenance schedule for Units No. 1 and 2 since start-up in 1973.

Year	Unit	Operating Hours Between Overhaul	Maintenance Period
1973	2	Start Operation 4/1973	
1973	1	Start Operation 9/1973	
1974	2	8325	39 days
1974	1	9380	42 days
1975	2	7533	27 days
1975	1	7937	32 days
1976	2	7169	26 days
1977	1	12119	32 days
1978	2	15596	36 days
1979	1	16943	36 days
1979	3	Start Operation 3/1979	
1979	4	Start Operation 4/1979	

Unit No. 2 is scheduled for major maintenance in February 1980 after 16,000 hours of operation, but maintenance is delayed until April 1980 to permit maintenance of Unit 4 earlier than planned.

Summary The CFE geothermal flash steam power plant has achieved a high capacity factor during five years of commercial service. Plant operation, design and maintenance have contributed to this geothermal energy electric production accomplishment.

Cerro Prieto operation as a base load geothermal plant has been stable and relatively simple compared to running a fossil fuel fired steam plant. Base load operation eliminates the thermal cycling stress problems that are encountered in peaking or load following steam plants. The plant personnel are confident that the plant capacity factor will remain at its high level for the next five year period.

Careful selection of material compatible to the geothermal steam is a major design consideration. Plant equipment can be designed with redundant systems when there is evidence that corrosive elements in the geothermal steam may cause problems that require maintenance outages. Design of the redundant system should insure uninterrupted operation of generating unit with emphasis on the capability to isolate the redundant system should it require maintenance.

Maintenance by plant personnel should be prompt, cost effective, and done with the goal that the repair problem will not occur again.

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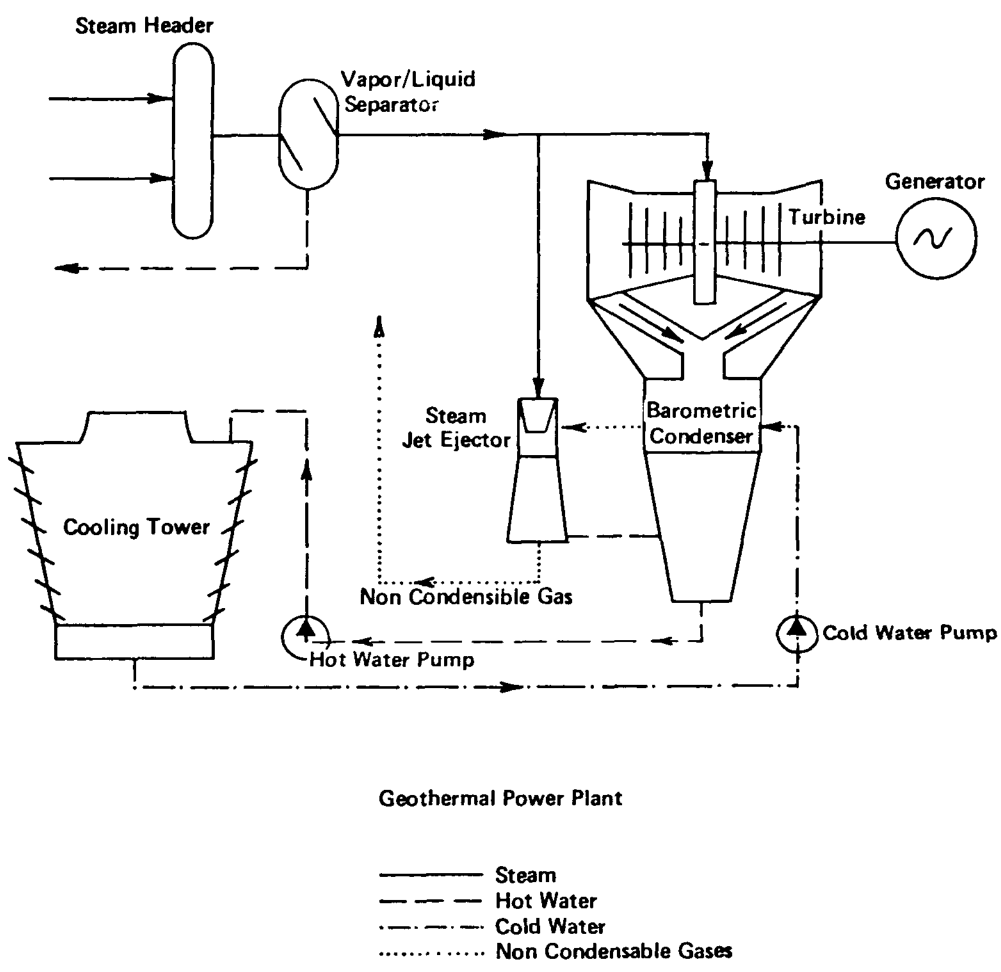

Geothermal Power Plant

Figure No. 1

SECTION: GEOTHERMAL STEAM ELECTRIC STATION

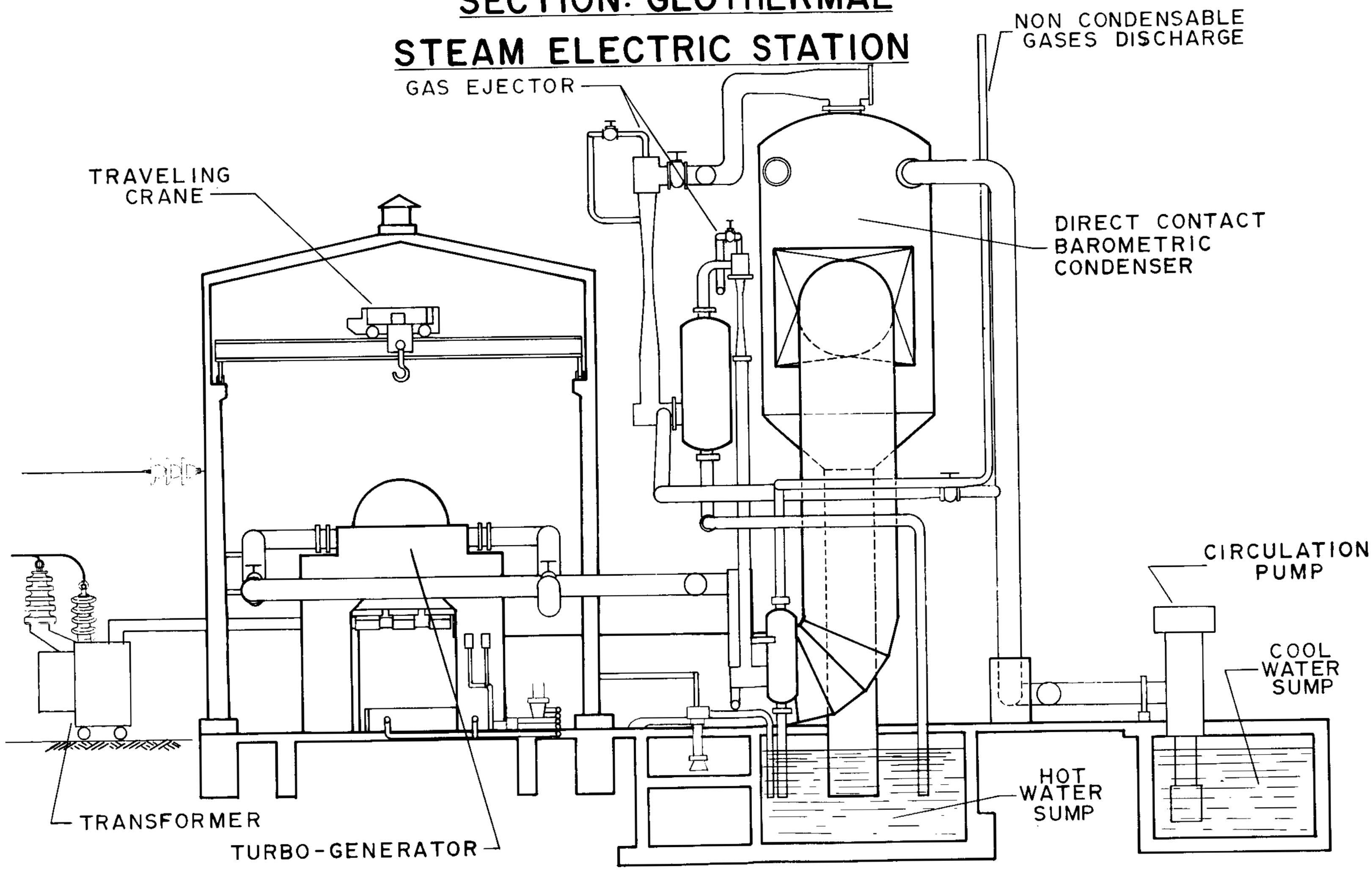

Figure No. 2

BAROMETRIC CONDENSER

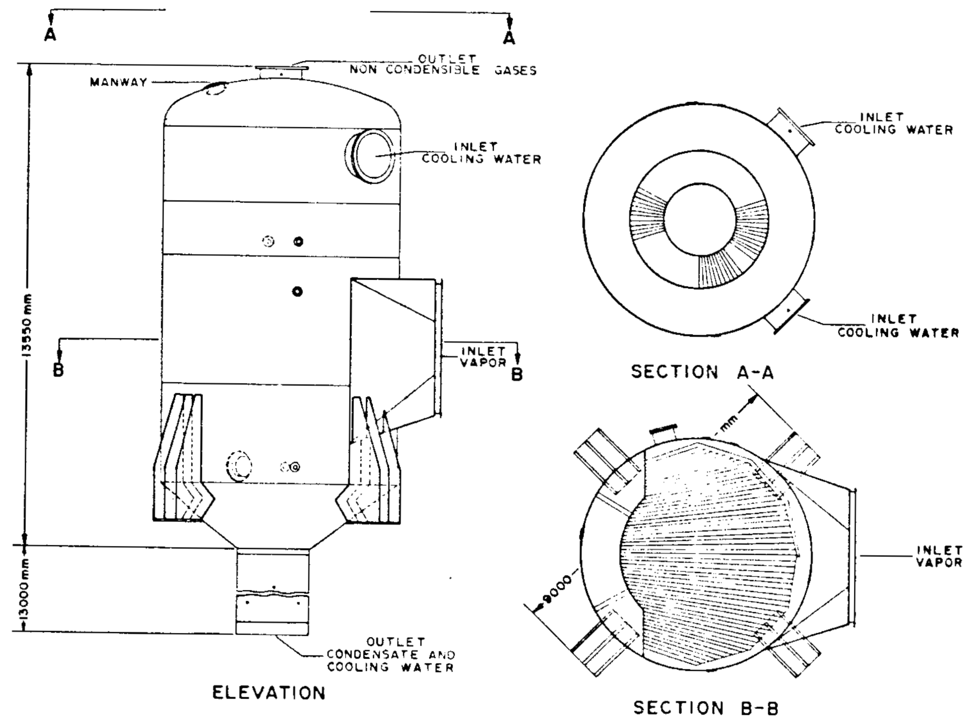

Figure No. 3

CENTRIFUGAL SEPARATOR

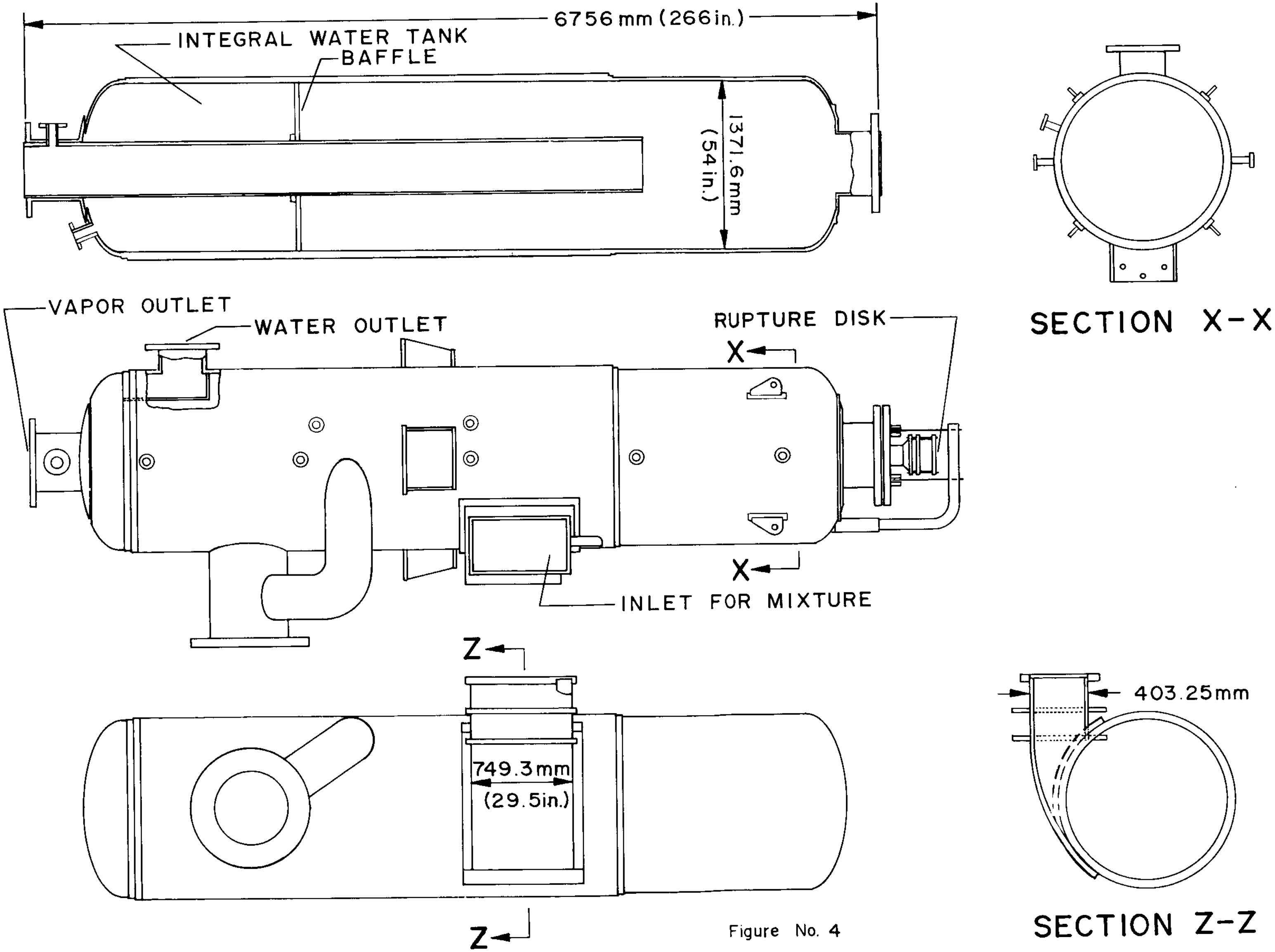

Figure No. 4

POWER PRODUCTION FROM GEOTHERMAL BRINE WITH THE ROTARY SEPARATOR TURBINE

Contract RP1196

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Abstract The rotary separator turbine is a new turbine device that operates with gas-liquid mixtures. This device achieves complete gas-liquid separation, generates power from the liquid and repressurizes the liquid.

The use of the rotary separator turbine for geothermal power generation was investigated on this program. A pilot scale unit was designed and tested. Tests were conducted with a clean water/steam mixture and with geothermal brine/steam flows at East Mesa, California; Raft River, Idaho; and Roosevelt Hot Springs, Utah.

The test results were used to calculate the performance advantage of a rotary separator turbine power system compared to a flash steam power system and a binary power system. The calculated performance advantages were then used to estimate market potential for wellhead and central station Biphase units.

The measured performance in the laboratory and in the field agreed to within ±10% of the predicted values. The design goal of 20 kWe was generated both in the laboratory and from brine. Separated steam quality was measured to be greater than 99.96% at all three geothermal resources and in the laboratory. Brine pressure leaving the test unit was greater than reinjection pressure requirements. (Maximum brine outlet pressure of 90 psig was demonstrated.)

The measured performance values would result in a 34% increase in electric power production above a single stage flash steam system. Increasing the size from the pilot size unit (20kWe) to a wellhead unit (2000 kWe) gave a calculated performance advantage of 40%. Based on these favorable results, design, construction and testing of a full-size wellhead unit was initiated.

1. Introduction

Generation of electricity from the hydrothermal geothermal resource is an important part of our country's future energy sources.[1,2] This is especially true in the western USA where the amount of available energy is sufficient to provide a significant fraction of the power for major metropolitan areas.

However, development of this resource has not progressed as rapidly as early predictions.[3] Some of the barriers to development have been institutional in nature--financing, legal, risk acceptance, environmental, regulatory. Other problems have a technological basis--scale deposition, corrosion, efficiency of energy conversion, cost. Rapidly escalating fuel costs make it imperative to solve these problems in the near future.

The rotary separator turbine is a new device[4] which has the potential of solving many of the aforementioned problem areas. The rotary separator turbine produces clean steam for steam turbines or heat exchangers directly from brine. Scaling and corrosion are less severe than in conventional separators. Additional power is generated from the brine itself. As much as 50% can be added to the energy of the steam flashed from the brine.[5] Finally, the separated brine is internally pressurized to the pressure required for reinjection.

The performance advantages, the compact size and the low cost of the rotary separator turbine should enable the development of smaller geothermal power systems (<20 MW) producing power at a cost which is competitive with larger conventional systems. The availability of a low cost skid mounted power system with standardized components should solve many of the institutional barriers mentioned. The lower capital investment (e.g., $10 million versus $80 million) will alleviate financing and reduce the risk. The risk of resource depletion is reduced because the power system can be readily relocated. The smaller power levels have many regulatory and environmental benefits under the present law.[6] The ability to produce power in 1-2 years from fewer wells enables a more immediate return on well completion investments.

The technology proven in smaller systems can also be applied to larger systems to achieve the same performance advantages. Wellhead rotary separator turbines or larger central units can be used. In either case more power per pound of brine than a two stage or single stage flash steam system has been calculated for measured rotary separator turbine performance levels.

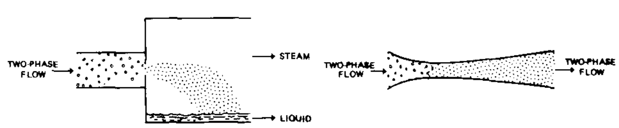
In order to demonstrate these gains a pilot scale rotary separator turbine was constructed and tested. A portable test system was used to test the unit in the laboratory and at several field sites. The test results were used to calculate the performance advantage of a rotary separator turbine power system compared to a flash steam power system and a binary power system. The calculated performance advantages were then used to estimate market potential for wellhead and central station rotary separator turbine units.

Subsequently, a wellhead Biphase rotary separator turbine was designed and is being manufactured. This unit will be tested on a geothermal well to demonstrate performance of a full size unit. These results will verify the calculated performance gains.

This paper will summarize results of testing the pilot scale unit, the calculated performance advantages and the design of the wellhead unit. In addition, a ten megawatt power system incorporating the wellhead unit will be described.

2. Principles of Operation The principles of operation of the rotary separator turbine can best be understood by considering its three major components: the two-phase nozzle, the rotary separator and the liquid turbine. In this section each will be explained. An example of each is given using typical flow conditions from a geothermal well.

Two-Phase Nozzle The purpose of the two-phase nozzle is to use the available thermal energy of brine and steam to impart kinetic energy to the brine droplets. This is illustrated in Figure 1 which shows the difference between a conventional flash process and a two-phase nozzle expansion.



	FLASH ORIFICE		TWO-PHASE NOZZLE	
	INLET	EXIT	INLET	EXIT
TEMPERATURE, F	481	327	481	327
PRESSURE, psia	475	99	475	99
VAPOR FLOW, lb/s	12.6	31.25	12.6	27.9
LIQUID FLOW, lb/s	112.4	93.75	112.4	97.1
VAPOR KINETIC ENERGY, kW	0	0	0	581.5
LIQUID KINETIC ENERGY, kW [1]	0		0	2024.3
VAPOR AVAILABLE THERMAL[2] ENERGY, kW		5043		4506.2
TOTAL AVAILABLE ENERGY, kW		5043		7112

(1) 51% OF AVAILABLE ENERGY IN ISENTROPIC EXPANSION FROM 475 TO 99 PSIA
(2) 70% OF AVAILABLE ENERGY IN ISENTROPIC EXPANSION FROM 99 TO 2 PSIA

Figure 1. Comparison of Two-Phase Nozzle Expansion with Flash Expansion

In the flash process the high pressure brine/steam mixture flows through an orifice or valve, lowering the pressure and causing more steam to flash. Since it is an isenthalpic process all the kinetic energy at the orifice is dissipated as heat. As a result the only usable energy is the thermal energy of the steam. For the example shown the total available energy is 5043 kW if the steam is expanded in a steam turbine with an efficiency of 70%. This process corresponds to path 0-1 in Figure 2.

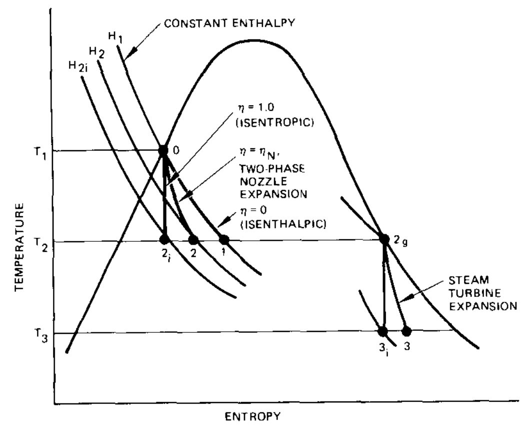


Figure 2. Temperature Entropy Diagram for Rotary Separator Turbine System

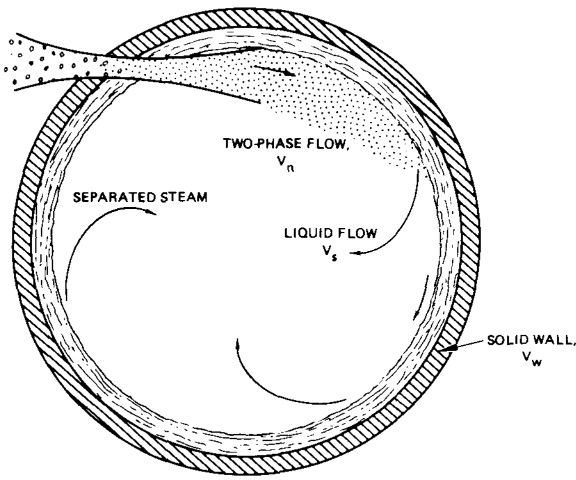
In the two-phase nozzle, the pressure is lowered *gradually* by changing the cross section. The steam which is formed pushes on the brine droplets as it flows to the nozzle exit. Thus, the steam does work on the brine droplets (much in the same manner as it would on turbine blades) imparting kinetic energy. At the exit of the nozzle there are three forms of usable energy: the steam kinetic energy, the brine kinetic energy, and the steam thermal energy. As shown in the example of Figure 1, these three energy sources are 582 kW, 2024 kW and 4506 kW giving a total available energy of *7112 kW*.

Referring to Figure 2, the flow through the two-phase nozzle follows the path 0-2. The exit point is at a lower enthalpy than the isentropic, path 0-$2i$. The difference in enthalpy, H_1-H_2, is converted to steam and brine kinetic energy. The amount of steam flashed is somewhat less in path 0-2 than path 0-1. In the example of Figure 1 this accounts for the larger steam thermal energy (5043 kW versus 4506 kW).

Referring to Figure 1, the total available energy at the nozzle exit is *7112 kW* compared to a total of *5043 kW* for the flash orifice. The difference, 2069 kW, is 41% greater than the energy available from the flash process.

Rotary Separator The additional kinetic energy in the brine can be converted to shaft power by impinging the two-phase jet directly on turbine blading.[7] However, large losses of liquid energy may be encountered as the brine flows at high velocity across extended blade surfaces.[8] Because of this and other disadvantages relating to corrosion/erosion and brine/steam management, a different approach to extracting the brine energy is used.

The approach used is to separate the brine from the steam *before* converting the kinetic energy to a useful form. Figure 3 illustrates the rotary separator used for this purpose and contrasts its performance to a cyclone separator.



	CYCLONE SEPARATOR	FREE WHEELING ROTARY SEPARATOR	ROTARY SEPARATOR WITH EXTERNAL DRAG
NOZZLE VELOCITY, V_n, ft/s	995	995	995
WALL VELOCITY, V_w, ft/s	0	888	755
LIQUID VELOCITY, ft/s		888	755
LIQUID ENERGY, KW		1612	1165
TOTAL PRESSURE, psia	99	5200	3787
LIQUID CARRYOVER, %	1-2	0	0

Figure 3. Comparison of Rotary Separator with Cyclone Separator

In both separators the two-phase jet impinges tangentially to a wall. In a cyclone separator the wall is stationary while in a rotary separator it is allowed to freely rotate in the same direction as the entering jet.

In a cyclone separator the kinetic energy of the brine is dissipated as friction on the wall. The resultant brine film has no energy available for recovery. Furthermore this slow moving brine layer is susceptible to reentrainment by the high velocity steam core. This secondary entrainment is responsible for the liquid carryover in this type of separator.[9]

In the rotary separator the moving wall means there is a very low relative impact velocity, minimizing erosion. The separated brine layer travels at the same velocity as the wall so there is only a small frictional energy loss. For the example of Figure 3 if the wall is allowed to freely rotate with the jet the brine energy available is *1612 kW*. The total pressure is *5200 psia* (more than 10 times the inlet nozzle pressure). If an external load were applied to the separator shaft to slow it down to 755 ft/s the kinetic energy of the rotating brine layer would be *1165 kW* and a total pressure of *3787 psia*.

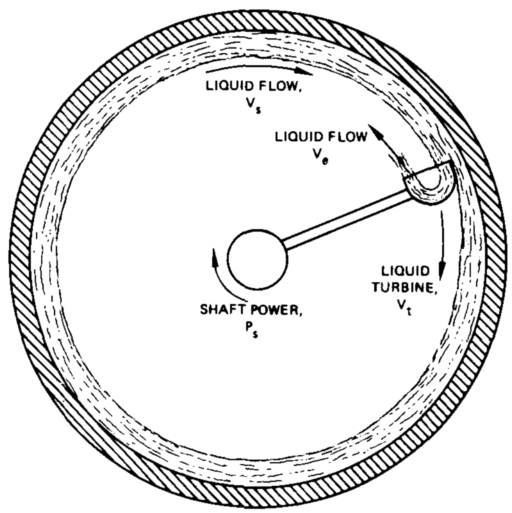
The kinetic energy could be recovered by simply inserting a pitot type diffuser into the flow. For a diffuser efficiency of 0.85 the outlet brine would be at 3218 psia in the latter case.

In this example, the separated steam flows radially inward and exits to a steam turbine. No attempt is made to recover the steam kinetic energy. However, radial inflow or impulse vapor blading can be mounted on the separator drum to recover the steam kinetic energy. A prototype of this type of rotary separator is currently in construction. The kinetic energy may also be converted to superheat to provide better steam conditions for the steam turbine. If the steam kinetic energy is dissipated in the rotary separator the resultant heat will produce an added amount of steam.

The rotary separator allows separation of the brine from the steam with minimum energy loss. The resulting brine flow has kinetic energy that can be converted to pressure in a diffuser or to shaft energy with a liquid turbine.

Liquid Turbine Conversion of the brine kinetic energy to shaft energy can be accomplished with a simple liquid impulse turbine. In Figure 4 the brine and drum wall are travelling at a velocity, V_s. If a scoop is immersed in this flow and constrained by a load to travel at a velocity $V_t = \frac{1}{2} V_s$, the absolute velocity (and energy of the brine) leaving the scoop at 180° is $V_e = \frac{1}{2} V_s - \frac{1}{2} V_s = 0$. The liquid turbine power transferred to the shaft for this case (with no losses) is *1165 kW*. This liquid impulse turbine is analogous to a gas impulse turbine but only a single scoop or tube is required to turn the flow through 180°.

If pressure is to be recovered in the leaving brine some kinetic energy must be left. In the second example of Figure 4 the liquid turbine tip speed V_t is 438 ft/s. The leaving brine velocity (with losses) is *168 ft/s*. This velocity corresponds to a total pressure of *282 psia* which may be recovered in a diffuser.



	TOTAL LIQUID POWER EXTRACTION	PARTIAL LIQUID POWER EXTRACTION
LIQUID VELOCITY, V_s, ft/s	755	755
LIQUID TURBINE TIP SPEED, V_t, ft/s	378	438
LIQUID VELOCITY AT EXIT, V_e, ft/s	0	168
LIQUID TURBINE POWER, P_s, kW	1165 (NO LOSS)	1051
ENERGY REMAINING IN LIQUID, kW	0	58
REMAINING TOTAL PRESSURE, psi	99	282

Figure 4. Comparison of Liquid Turbine Operating Modes

Assembly The assembly of these components into a complete rotary separator turbine is shown in Figure 5. The brine/steam mixture flows through a two-phase nozzle and is directed tangentially on the freely rotating drum. The steam is separated by centrifugal forces and flows radially inward and out the port to a steam turbine. The brine layer on the primary rotary separator flows through holes to the other side of the support disc.

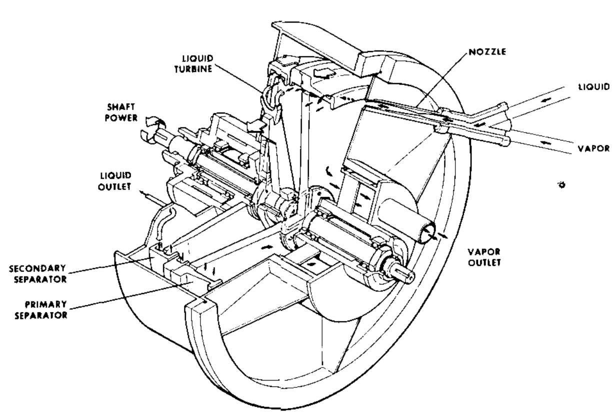


Figure 5. Rotary Separator Turbine Assembly

The brine layer drives a liquid impulse turbine immersed in the flow. The liquid turbine shaft is connected to a generator or other load. The brine leaving the scoop of the liquid turbine is collected on a second free-wheeling separator drum. A stationary diffuser, immersed in the flow collects and repressurizes the brine for reinjection.

The net power available after consideration of all losses is summarized in Table I. The rotary separator turbine used with a steam turbine generates *6308 kW* versus *5043 kW* for a flash steam turbine. Addition of 70% efficient steam impulse blading would increase the rotary separator turbine system output to *6715 kW*. Thus the brine rate can be *67 lb/kWh* for this example compared to *89 lb/kWh* for the flash steam turbine.

Table I

COMPARISON OF TOTAL USEFUL ENERGY
FOR A ROTARY SEPARATOR TURBINE
SYSTEM AND FLASH STEAM SYSTEM

	Flash Steam	Rotary Separator Turbine
Steam Turbine kW	5043	4684
Liquid Drag Turbine kW	0	410
Liquid Impulse Turbine kW	0	1165
Energy for Pumping kW	0	49
Total Useful Energy	5043	6308

$$\text{Brine Utilization Ratio} = \frac{6308}{5043} = 1.25$$

The operating principles and component parts of a rotary separator turbine are very simple. Calculation of the performance for a high temperature geothermal well shows a 25-30% gain is possible. The same relations applied to lower temperature resources give even larger gains.

3. Experimental Results The main purpose of the experimental program was to establish the validity of the performance relations used to design rotary separator turbines. In order to accomplish this purpose a unit was designed and tested both in the laboratory and in the field.

Experimental Turbine The experimental turbine is shown schematically in Figure 5. The unit was designed to operate with a brine/steam mixture for test periods up to 500 hours. The rotor and case were constructed from aluminum with a protective coating. Bearing, seals and other ancillary components were off-the-shelf. The resulting unit was suitable for performance testing and evaluation of scale deposition. Figure 6 is a photograph of the unit during operation in the field. The key geometric parameters are summarized in Table II.

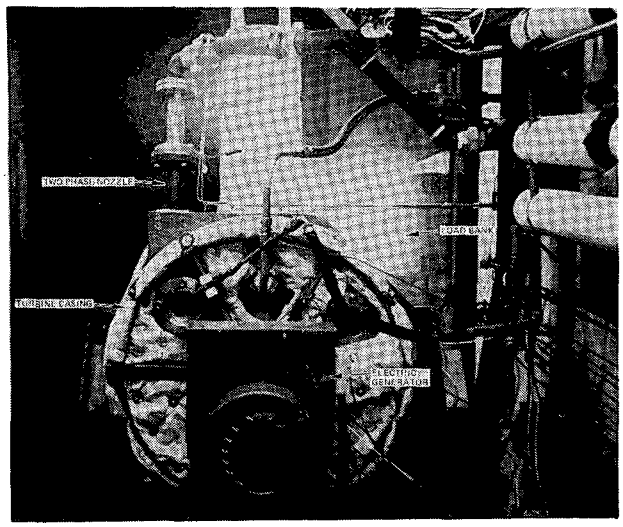


Figure 6. Pilot Scale Rotary Separator Turbine Operating in Field

The calculated power output was 20.8 kW for a brine pressure of 80 psia and a vapor quality of 4.4% at the inlet to the nozzle. This corresponds to a brine flow rate of 4.7 lb/s. Since the nozzle has a fixed throat, operation at conditions other than the above results in the nozzle being off-design. Depending on the nature of the deviation the predicted turbine power can either increase or decrease. Figure 7 gives the predicted power output versus nozzle inlet pressure for different inlet vapor quality. Decreasing the vapor quality from .05 to .01 at 80 psia increases the power from 20 kW to about 24 kW. Decreasing the inlet brine pressure from 80 psia to 60 psia at a vapor quality of .05 reduces the power from 20 kW to about 14 kW. The performance at the design point is summarized in Table III.

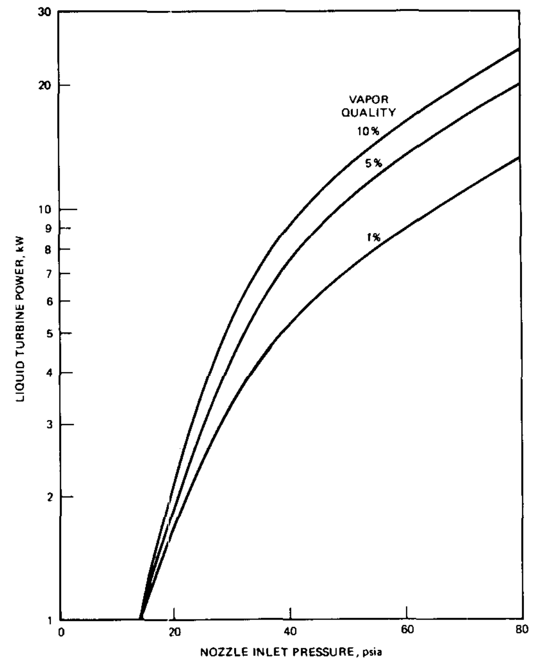


Figure 7. Power Output Variation with Nozzle Inlet Pressure

Test System The rotary separator turbine was installed in a flow system which had been fabricated in a 40 foot trailer. All controls and instrumentation for the flow system were contained in the trailer to facilitate testing at field sites. Figure 8 is a schematic of the test system. In the laboratory the geothermal well was replaced by a boiler.

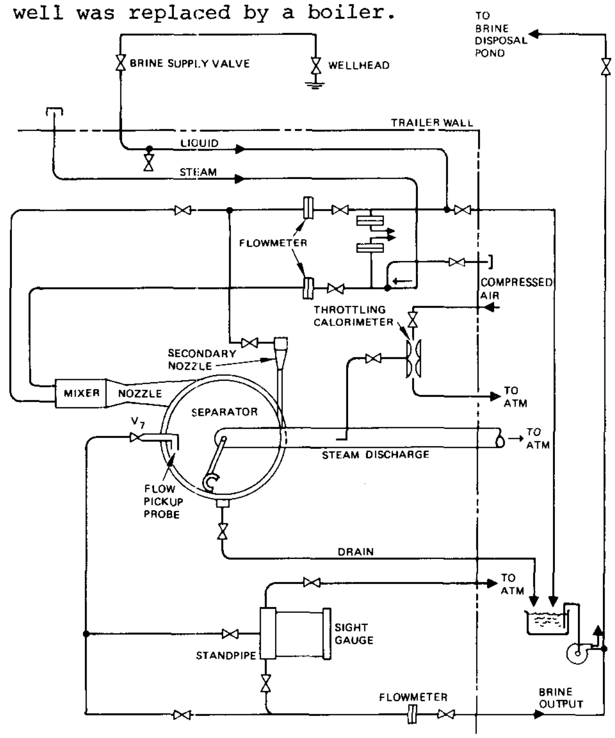


Figure 8. Rotary Separator Turbine Field Test System

The brine and steam flows were manually controlled and measured with oridice flow meters. The pressure of the brine discharge from the rotary separator turbine was controlled with a manual throttling valve. The stream flow from the test unit was sampled with a throttling calorimeter before being discharged to atmosphere. Figure 9 is a photograph of the test trailer and turbine during operation at Roosevelt Hot Springs.

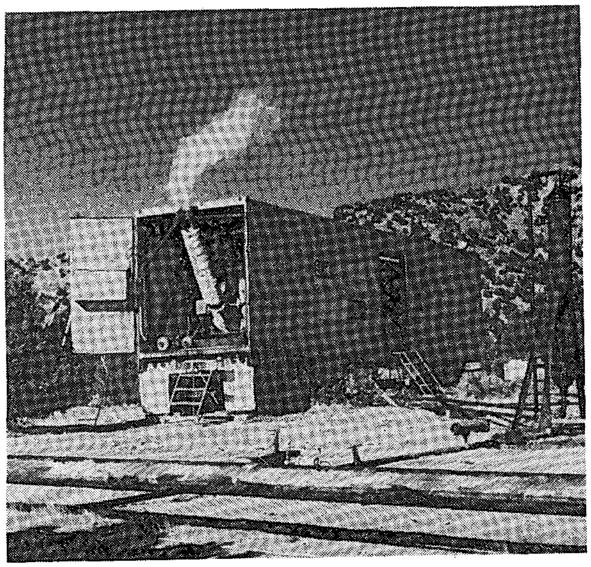


Figure 9. Test System During-Operation at Roosevelt Hot Springs

Test Parameters The rotary separator-turbine was tested at the laboratory of Biphase Energy Systems in Santa Monica, California and at three geothermal resources. The geothermal resources were DOE wells at East Mesa, California and Raft River, Idaho and a Phillips Petroleum well at Roosevelt Hot Springs, Utah. The range of parameters tested is summarized in Table IV. Design values of brine pressure and inlet vapor quality were attainable only at Roosevelt Hot Springs.

Test Experience The rotary separator turbine operated smoothly producing electricity and clean steam at all four test sites. Calcite scaling at East Mesa and Roosevelt Hot Springs was eliminated completely by injecting 2-10 ppm of an organic phosphate. No brine pretreatment was used at Raft River. A total of 191 performance tests at East Mesa, 68 at Raft River and 101 at Roosevelt Hot Springs were conducted. The total operating time logged by the test turbine was 230 hours.

Performance The rotary separator turbine generated electric power from the brine, produced clean steam and repressurized the separated brine. Table V summarizes the measured results. Output power ranging from 0-22 kW was measured. Separated steam quality of greater than 99.9% was obtained at all three test locations. Brine/water outlet pressure as high as 90 psia was provided by the separator.

The data obtained at Roosevelt Hot Springs was with saturated steam-brine at the nozzle inlet flow. The other two test sites had subcooled brine. Therefore the measured performance at Roosevelt Hot Springs provides the best basis for comparison with theory. Figure 10 is a plot of measured versus predicted power output for all test conditions. As can be seen, agreement is excellent. The deviation from theory is about ±10%, well within the accuracy of the instrumentation. *These test data validate the calculated model*, which was used to design the pilot scale turbine and to predict performance of the Biphase turbine. The data also validate the use of the model to predict off-design behavior for a fixed geometry rotary separator turbine.

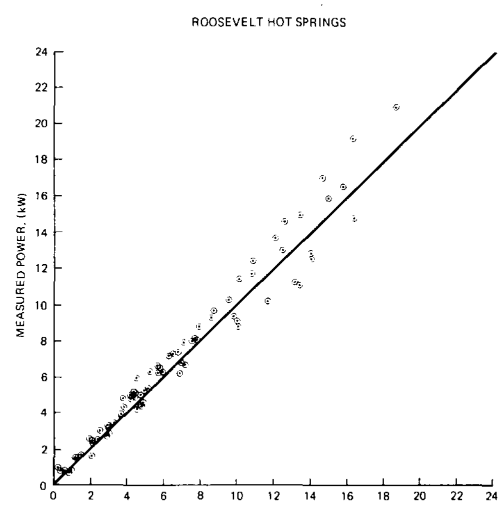


Figure 10. Comparison of Measured and Calculated Power Output for Rotary Separator Turbine

The measured output power represents an addition to the power which could be generated if the same brine flow was flashed and the resulting steam used to drive a steam turbine. The ratio of the total of power output to the available brine energy is defined as the resource utilization efficiency, η_u.

Figure 11 shows the theoretical value of η_u plotted versus flash temperature for the inlet brine conditions at Roosevelt Hot Springs for a Biphase expander efficiency of 38% and for a flash steam system. The measured performance at the design condition is shown for comparison. As can be seen, the measured performance represents a value of η_u which is a 34% increase in power output above a single stage flash steam system.

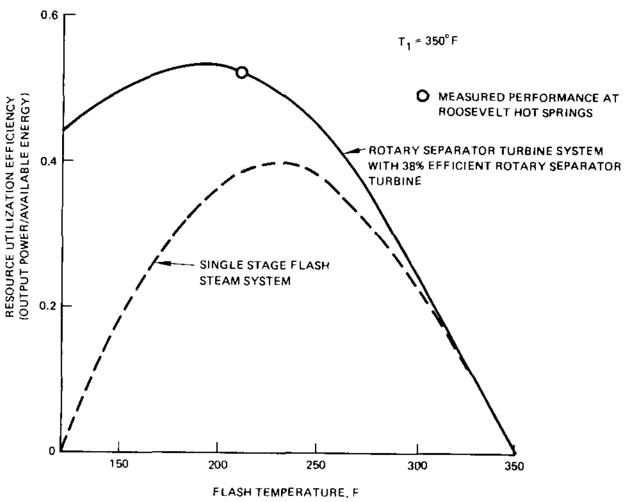


Figure 11. Resource Utilization Efficiency Versus Flash Temperature for Rotary Separator Turbine and Flash Steam Turbine Systems with a 350°F Resource Temperature

The field test results are significant not only because the Biphase rotary separator turbine operated as predicted, but also because a 34% performance advantage over a flash steam system was demonstrated.

4. Wellhead Rotary Separator Turbine The successful tests of the pilot scale turbine and estimates of its impact on generation of commercial power from geothermal led to the design of a wellhead turbine. This demonstration unit was designed to handle the brine-steam mixture from a geothermal well. Outputs of the wellhead rotary separator turbine will be clean steam to drive a steam turbine, electric power from the brine and high pressure separated brine for reinjection.

The wellhead rotary separator turbine is shown in Figure 12. The two-phase nozzles (not shown) generate a high energy brine/steam mixture that impinges on the primary separator. The separated steam flows to a steam turbine. The brine rotating with the primary separator is used to drive an open U-tube liquid turbine. The brine leaving the liquid turbine is collected on the secondary separator and repressurized by the diffuser for reinjection. A key design feature of this unit is that reinjection pressures are provided with no seals or bearings exposed to the brine.

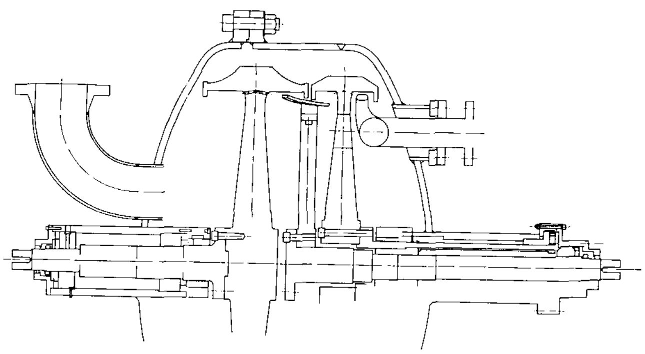


Figure 12. Wellhead Rotary Separator Turbine

The diameter of the separator is 4½ feet. The material of construction is HY80 carbon steel for low to moderate temperature resources. For high temperature resources, a plasma deposited inconel coating is planned. The casing is designed to contain any fragments in the unlikely event of a rotor failure.

The rotor was designed with a finite element stress analysis to provide the greatest margin of safety. The resulting geometry has a stress level which is only 55% of the free hoop stress.

Tilting pad bearings are used for the primary separator and liquid turbine shafts. The secondary separator uses conventional journal bearings. A conventional lube oil system is utilized for lubrication and heat removal from the bearings.

The wellhead rotary separator turbine was designed to process a brine flow of 200,00 to 800,000 lb/h. At the nominal design point of 450,000 lb/h at 475 psia (464°F), the liquid turbine power is *1575 kW* without the steam blading and *2000 kW* with steam blading. Increasing the flow rate to the full 800,000 lb/h capacity at Brawley, California with the attendant increase in pressure would produce about *4000 kW* from the wellhead unit with an added 9000 kW available from the separated steam.

The ratio of power output from the wellhead unit plus a single steam turbine to that from single stage flash steam system and two stage flash steam system is shown in Figure 13. As can be seen, a maximum advantage of 50-60% can be realized compared to a single stage flash steam system and 10-20% compared to the dual flash steam system. The performance advantage was calculated using the performance relations which were verified by the field tests (cf Figure 10). Thus, for example, a single stage flash steam plant designed to operate at 460°F could have its power increased from 50 MW to 70 MW by the addition of several rotary separator units. The brine leaving the separators would be at full reinjection pressure (e.g., 300 psia) without reinjection pumps.

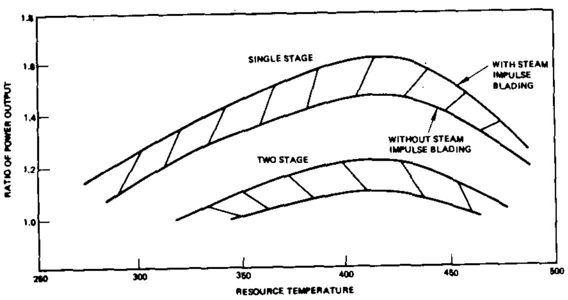


Figure 13. Wellhead Rotary Separator Turbine System

5. Geothermal Power System The results of the field tests were used to design a complete geothermal power system. This system would use the flow from 2-4 wells (depending on pressure and temperature) to produce 10 MW net electrical power. Reinjection would be accomplished by the rotary separator turbine. Heat rejection would be by cooling towers with makeup water from the condensate.

Figure 14 is a schematic of the 10 MW power system. This specific unit was designed to accept the flow from 4 wells with wellhead conditions of 341°F brine with a steam quality of 8.1%. For these conditions the net power is 6.2 MW. The flow rate is 1,800,000 lb/h total giving a brine rate of 146.1 lb/kWh.

The 10 MW system actually consists of two identical skid mounted 5 MW units which can be physically separated. The major component parts of the 10 MW power system are summarized in Table VI. Most are off-the-shelf or of standard design. The increase in power output resulting from the rotary separator turbine and use of standardized components result in a cost range of about 800 to 1000 $/kWe. This low capital cost, the short construction time (15 months), and the requirement of only a few wells should combine to produce power at a cost lower than a larger system using the flash steam cycle or binary cycle.

6. Conclusions A geothermal rotary separator turbine was designed and tested in the laboratory and at three geothermal resources. The experimental results were in substantial agreement with theory. The test turbine demonstrated 34% power addition to the output of a single stage flash steam system. In addition the test unit provided clean steam for a steam turbine and high pressure brine for reinjection.

These favorable results and even greater performance advantages calculated for a wellhead unit led to the design of a 10 MW power system incorporating the rotary separator turbine. The low cost of this system indicates a substantial market may exist for rotary separator turbines and that this technology may accelerate commercialization of the geothermal resource.

7. References

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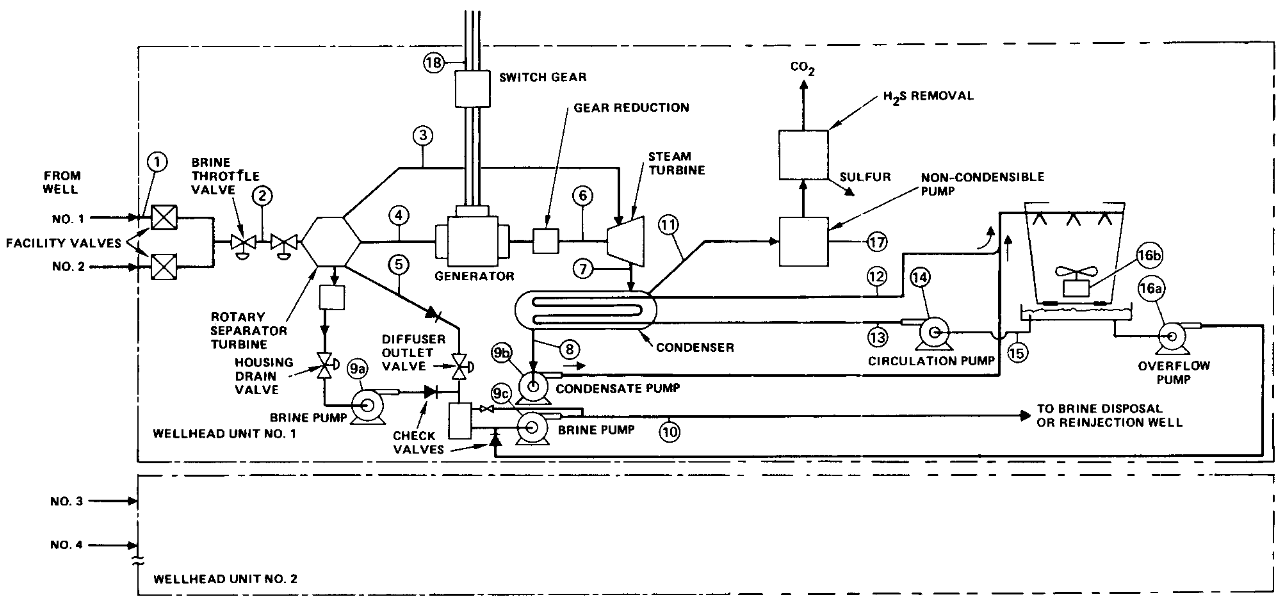
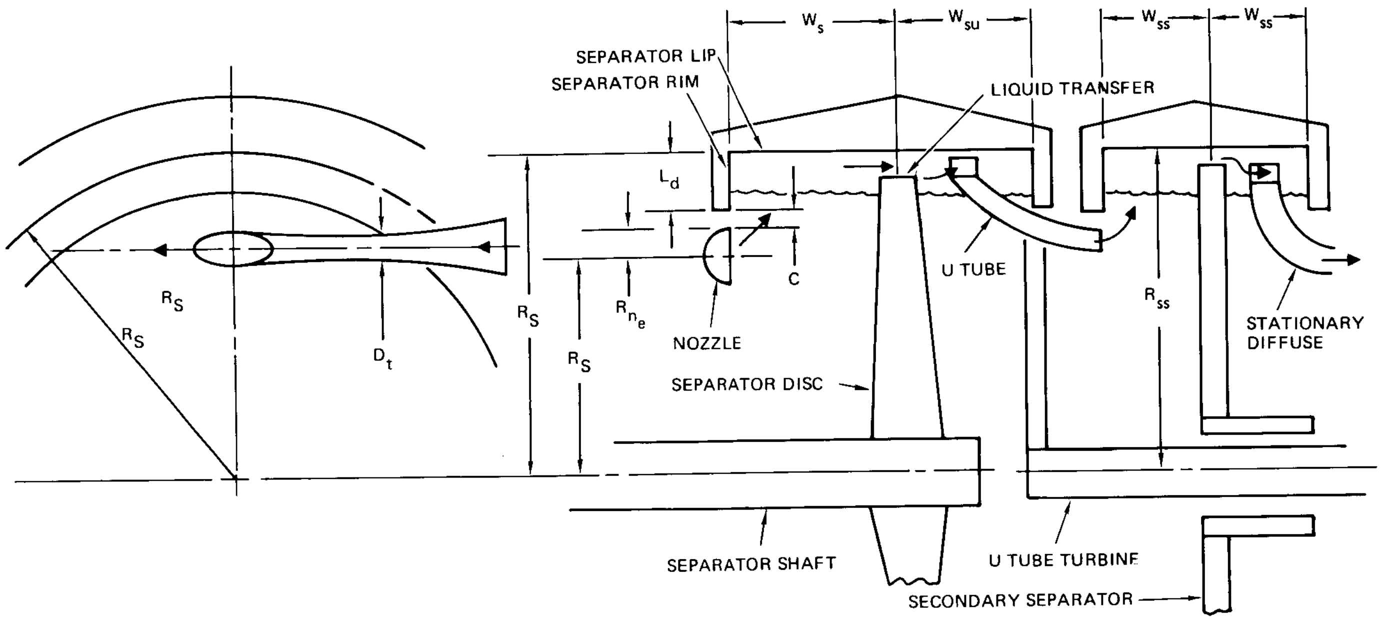


STATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18		
MEDIA	Brine	Brine	Steam	Power	Brine	Power	Steam	Cond.	Power	Brine	Non-Cond.	Water	Water	Power	Water	Power	Power	Power		
PRESSURE, psia	277	120	30	–	121	–	2	2	–	250	2	50	90	–	15	–	–	–		
TEMPERATURE, °F	410	341	250	–	250	–	126	126	–	210	126	113	75	–	70	–	–	–		
FLOWRATE, 1bm/s	125	250	39.8	–	210.2	–	39.8	39.8	–	250	0.22	1400	1400	–	1400	–	–	–		
OUTPUT POWER, MW	0	0	0	1.1	–	5.8	–	–	-0.22	–	–	–	–	-0.17	–	-0.23	-0.12	=6.16		
STEAM FRACTION	0	0.08	0.16																	

Wellhead Unit Summary

Figure 14. Ten Megawatt Geothermal Wellhead Process Flow Diagram

Table II. Geometric Parameters for Test Turbine



RADIUS OF PRIMARY SEPARATOR,	in,	R_s	15
RADIUS OF SECONDARY SEPARATOR,	in,	R_{ss}	15
RADIUS OF NOZZLE EXIT,	in,	R_{n_e}	1.0
DIAMETER OF NOZZLE THROAT,	in,	D_{n_t}	1.133
RADIAL LOCATION OF NOZZLE,	in,	R_n	13
NOZZLE INCLINATION,	deg,	θ	16
SEPARATOR RIM HEIGHT,	in,	L_d	0.5
NOZZLE TO SEPARATOR CLEARANCE,	in,	C	0.5
SEPARATOR RIM WIDTH,	in,	W_s	3.9
SEPARATOR RIM WIDTH, U TUBE SIDE,	in,	W_{su}	1.5
SECONDARY SEPARATOR RIM WIDTH,	in,	W_{ss}	0.86
U TUBE INLET HEIGHT x WIDTH,	in,		0.4 x 0.6
DIFFUSER INLET HEIGHT x WIDTH,	in,		0.4 x 0.5

Table III. Design Performance of Test Turbine

		WELLHEAD	MIXER INLET	NOZZLE INLET	NOZZLE EXIT	SEPARATOR		UTUBE TURBINE	UTUBE EXIT	SECONDARY SEPARATOR	DIFFUSER
STATION NO.	psia	1	2	3	4	5		6	7	8	9
PRESSURE	psia	90	144	80	14.7	14.7	14.7	14.7	14.7	14.7	56
TOTAL FLOWRATE	lbm/s	4.7	4.7	4.7	4.7	0.6	4.1	4.1	4.1	4.1	4.1
LIQUID FLOWRATE	lbm/s	4.7		4.5	4.1	0	4.1	4.1	4.1	4.1	4.1
STEAM FLOWRATE	lbm/s	0		0.2	0.6	0.6	0	0	0	0	0
QUALITY	%	0		5	13.8	100	00	0	0	0	0
VELOCITY	ft/s	50	50	50	660	660	523	303	114	103	20
ROTATIONAL SPEED	rpm	0	0	0	0		4026	2335		786	0
COMPONENT EFFICIENCY	%	100	100	100	67	0	65 55	91	81	82	
POWER	KW	64	64	64	43.1	4.6	23.6	– 1.7	1.1	0.9	0.7
NET OUTPUT		$\Sigma = 21.5 \Rightarrow$		0	0	0	20.8	20.8	0.7	0	0.7

Table IV. Range of Test Parameters

	MINIMUM	MAXIMUM
SYSTEM INLET (WELLHEAD EQUIVALENT)		
BRINE FLOWRATE, lbm/s	0.7	13.8
BRINE PRESSURE, psia	72	161
BRINE TEMPERATURE, °F	254	349
RST		
POWER OUTPUT, LIQUID TURBINE, KW	0	21.1
SEPARATOR SPEED, rpm	900	4004
TURBINE SPEED, rpm	600	2074
SECODARY SEPARATOR SPEED, rpm	309	993
HOUSING PRESSURE, psia	7.5	15.9
SYSTEM OUTLET		
STEAM FLOWRATE, lbm/s	0.08	1.56
STEAM QUALITY, percent	20.55	99.95
BRINE PRESSURE, psia	17	100

Table V. Rotary Separator Turbine Performance Comparison

	WELLHEAD CONDITIONS (NOZZLE INLET CONDITIONS) FLOWRATE LBM/S	TEMP °F	PRESS PSIA	QUAL PERCENT	EFFICIENCY NOZZ	SEP	U	RST	RESOURCE UTILIZATION FACTOR	LIQUID TURBINE POWER kW	SPECIFIC POWER kW/LBM/S	OUTPUT STEAM QUALITY PERCENT	OUTPUT BRINE PRESSURE PSIA	CIRCUMSTANCES OF MEASUREMENT MODS/DATE/SCAN
DESIGN CONDITIONS	4.7 (4.7	355 312	153 80	0 5)	66	71	85	40	1.347	28.4	5.48	99.9	129	
LABORATORY TESTS	5.1 (5.1	348 331	133 105	– 1) 4)	58	61	85	30	1.22	20.1	3.94	–	56	1/12/79
EAST MESA	6.25 (6.25	319 313	150.7 84.5	–40 – 4	55	51	89	30	1.19	14.9	2.38	99.9	41	2/26/79 - 133 TURBINE ALIGNMENT
LABORATORY TESTS	3.28 (3.28	348 312	130 80	– 3 4.6)	57	58	87	29	1.25	14.4	4.39	–	–	5/7/79 4 NOZZLE EXTENSION
RAFT RIVER (WITH EDUCTOR)	4.38 (4.58	273 271	63.2 44.7	–23 – 5)	50	67	87	29	0.76	7.2	1.57	–	31	5/30/79 68
RAFT RIVER	4.9 (4.9	273 272	62 45	–22 – 3)	34	64	88	19	1.08	3.3	0.67	97.1	25	3/30/79 56
ROOSEVELT HOT SPRINGS	4.1 (4.1	352 314	138 83.8	0 4.2)	61	68	87	36	1.305	20.9	5.1	99.4	70	10/9/79 99 DIFFUSER REPLACEMENT
LABORATORY TESTS	3.6 (3.6)	348 307	137 73	0 (4.9)	56	58	88	29	1.25	13.4	3.7	99.94		1/3/80

Table VI. Components of 10 MW Power System

COMPONENTS	MANUFACTURER – MODEL NO.
1. ROTARY SEPARATOR TURBINE	TRANSAMERICA-DELAVAL – RST-54-3
2. ELECTRICAL GENERATOR	GENERAL ELECTRIC – 002-8912
3. GEAR TYPE SPEED REDUCER	TRANSAMERICA-DELAVAL – HG-SPECIAL
4. STEAM TURBINE	TRANSAMERICA-DELAVAL – LG-5
5. COMBINED BRINE CASE DRAIN TANK AND STEAM DROPOUT TANK	TRANSAMERICA-DELAVAL
6. BRINE HOLDING TANK	TRANSAMERICA-DELAVAL
7. MAIN BRINE PUMP	WORTHINGTON – 6LR18
8. CASE-DRAIN BRINE PUMP	WORTHINGTON – D-1011
9. VACUUM PUMP	NASH
10. CONDENSER	TRANSAMERICA-DELAVAL – 65
11. CONDENSATE PUMP	WORTHINGTON – D-1011
12. OIL SUPPLY TANK	TRANSAMERICA-DELAVAL – 12 x 36
13. RESERVE OIL TANK	TRANSAMERICA-DELAVAL
14. PUMPS (2)	TRANSAMERICA-DELAVAL
15. COOLER	TRANSAMERICA-DELAVAL
16. PURIFIER	TRANSAMERICA-DELAVAL
17. FLOW CONTROL	FOX BORO
18. ELECTRICAL	FOX BORO – SPEC 200/FOX 3
19. SYSTEM INSTRUMENTATION a) FIELD b) REMOTE MONITORING	FOX BORO – SPEC 200/FOX 3
20. COOLING TOWER MODULE (6 REQUIRED)	MARLEY – 452-301
21. COOLING WATER CIRCULATION PUMP	WORTHINGTON – 14LN17A
22. COOLING TOWER LEVEL CONTROL PUMP	WORTHINGTON – D-811

COMPUTER SIMULATION OF SCALE FORMATION

RP653-3

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INTRODUCTION This paper summarizes results of recent analyses performed by Battelle-Northwest in EPRI project RP 653-3: Computer Simulation of Scaling in Geothermal Systems. The results reported here are drawn primarily from case evaluations performed over the 12 months since the preceding EPRI Geothermal Symposium held in Monterey in June 1979.

The present project is a continuation of a previous project designated RP 653-1. The ultimate objective of research performed in this project is to develop analytical tools (computer codes) and the supporting thermophysical and chemical data base that can be used to predict scaling and corrosion in geothermal power generating systems. The primary codes developed in the project and the functions of each are as follows:

- EQUILIB--provides chemical equilibrium computations for a brine as a function of thermodynamic state
- FLOSCAL--provides kinetics of deposition and corrosion processes for specified flow geometry and conditions
- PLANT--provides a steady-state geothermal power plant model with provision for scale specifications at key points
- GEOSCALE--an executive routine that calls the other codes to generate a time-dependent geothermal power plant model

In addition to the above, a new code entitled WELL has been developed for modeling flow in a flashing well. WELL was developed by adapting and merging well routines developed independently in FLOSCAL and PLANT.

Most of the essential elements of the codes developed in the previous project were functioning satisfactorily at the end of that work. However, the codes were at that time essentially untested and were known to be deficient in a number of ways. It was thus apparent that the codes were not yet ready to be released for general use by industry. The present project was initiated to provide a period of applications, testing, and refinement.

In addition to the code applications task, there have been a number of other activities that will ultimately facilitate the use of the codes. One of the first tasks undertaken in the present work was to prepare a standardized Input/Output document (1). The principal function of this document is to provide a complete and organized specification of the data required for input by the code operator. In addition, the I/O document provides a summary explanation of the type of output provided. This document has been completed and is now available for general use in preparation of cases for analysis.

Another aspect of the current work also relates to code dissemination. Preliminary steps in this direction were taken with the presentation of a workshop in November 1979 held at BNW in Richland. A proceedings of the workshop has been prepared (2) that will be published and distributed by EPRI in the near future.

One of the primary tasks that remains in completion of the present project is the completion of user manuals for the codes. A WELL code manual has been written and is being edited and revised. The original manuals prepared for EQUILIB and FLOSCAL in RP 653-1 will be revised and updated to reflect improvements developed in the present work and to provide up-dated test cases and examples. The completed manuals should be available by late 1980 or early 1981.

RESULTS OF CASE EVALUATIONS The work in the present project has been primarily directed at application, testing, and refinement of the codes by applying them to prediction of scaling in actual geothermal systems. The work has been organized by cases where each case represents a specific facility or class of test data to be simulated. The cases completed, in progress, and planned for completion in CY 80 are summarized in Table 1. Summaries of the results of the first four cases were presented at the 1979 Symposium (3). Cases 5-8 are summarized in the present paper. The other case analyses were still in progress at the time this paper was written.

- Heber 2000 hr Heat Exchanger Tests
- Cerro Prieto Flashing Wells
- Kizildere Flashing Flow Tests
- RGI East Mesa Flash Tests
- Power System Equipment Module Tests
- SCE Flash Plant at Heber
- Flashing Flow in Porous Media
- o Coury H_2S Removal System
- o BACA Flash Plant, New Mexico
- o GLEF Experiments

Table 1 Summary of Cases Evaluated

• completed, o in progress

In the process of performing the case evaluations, the codes and, particularly, the data base have evolved somewhat from one case to the next, due to improvements made along the way. The biggest changes have been in the data base. The simulations of the PSEMT and SCE plant were done with data derived primarily from the Helgeson-69 data (4), with a few additions and improvements. The Porous Medium Flash and Coury Heat Exchanger simulations were performed with a hybrid data base that used elements of the Helgeson-69 data and new data denoted Helgeson-78 (5), plus several other improvements derived from various sources. It is thought that this latter data base is more nearly correct; however, there are still some apparent anomalies that have not been entirely removed. Improvement of the data base is a task that will probably never be completely finished.

1. Power System Equipment Module Tests (PSEMT) The Power System Equipment Module Test (PSEMT) program was a study of heat exchanger performance under conditions representative of geothermal power plant operation. The project was sponsored by EPRI. The prime contractor and operator of the facility was Colley Engineers and Constructors. The PSEMT facility was located on the site of the 10 MW geothermal power plant operated by the Imperial Magma Company at the East Mesa geothermal field near Holtville, CA.

Description of the Test Facility A simplified schematic of the PSEMT facility is given in Figure 1. Hot brine was provided from one or more of the Magma wells, and the cooled brine was returned to the Magma system for reinjection. The brine was maintained in liquid phase at all times. Energy extracted from the brine heated the isobutane coolant to above its critical point, from which it was subsequently expanded, condensed, and recycled. The entire heat load was rejected to the surroundings in a cooling tower.

During the testing phase the performance of the heat exchanger was monitored as a function of time. Performance parameters monitored included

- overall and surface heat transfer coefficients for both brine and hydrocarbon sides and
- rates and distribution of scale deposition and corrosion.

Results of the experiments were not available for comparison with the computations at the time this paper was prepared.

Brine Characterization Brine property data and compositions for the Magma wells were established from the results of several sample analyses. These included brine samples taken by the PSEMT staff and analyzed for aqueous concentrations by GHT Laboratories. Samples were also taken and analyzed by Battelle. These data were combined with that obtained by the PSEMT staff to characterize the brine. These results are given in the first column of Table 2.

Material	Concentration (moles/kg brine) Sample	After Mineral Equilibration
K^+	$.6691 \times 10^{-2}$	$.6691 \times 10^{-2}$
Na^+	.1277	.1242
Ca^{++}	$.8882 \times 10^{-3}$	$.4636 \times 10^{-3}$
Mg^{++}	$.2962 \times 10^{-4}$	$.2962 \times 10^{-4}$
Fe^{++}	$.6924 \times 10^{-5}$	$.4166 \times 10^{-9}$
Fe^{+3}	--	$.8638 \times 10^{-13}$
Si	$.4175 \times 10^{-2}$	$.3482 \times 10^{-2}$
A_s^{+3}	$.5311 \times 10^{-5}$	$.5311 \times 10^{-5}$
A_s^{+5}	--	$.1558 \times 10^{-8}$
S^{--}	$.4695 \times 10^{-4}$	$.4695 \times 10^{-4}$
SO_4^{--}	$.8557 \times 10^{-5}$	$.8557 \times 10^{-3}$
CO_3^{--}	$.3849 \times 10^{-1}$	$.3807 \times 10^{-1}$
Cl^-	.1217	.1217
H^+	(pH = 5.72)	$.7815 \times 10^{-6}$
$H_2(\ell)$	--	$.6836 \times 10^{-6}$
NH_3	$.8560 \times 10^{-3}$	$.8559 \times 10^{-3}$
BaO_3^-	$.8196 \times 10^{-3}$	$.8196 \times 10^{-3}$
Sr^{++}	$.7943 \times 10^{-4}$	$.7943 \times 10^{-4}$

Table 2 Brine Composition Used as Input for FLOSCAL Simulations

This average brine specification should normallybe a suitable starting point for FLOSCAL simulation of scale deposition. Unfortunately, inaccuracies in the data base frequently result in predictions of lower levels of selected materials in the brine at saturation than are observed experimentally. Hence, using the "average" brine would start the flowstream with excessive supersaturations that would result in excessive precipitations. The following EQUILIB sequence was, therefore, run to generate a brine compatible with the data base.

1. Aqueous equilibration of the measured brine composition at 37°C

2. Raising the sample to reservoir temperature (182.2°C) under closed conditions for gases, but sulfide/sulfate ratio held constant

3. Mineral equilibration at reservoir temperature

This procedure resulted in precipitation of small amounts of calcite and quartz, and a large amount of Minnesotaite $Fe_3SI_3O_{10}(OH)_2$ at 182.2°C. This indicates that the brine was possibly at equilibrium with these materials at reservoir conditions. The iron concentration in solution was reduced by three orders of magnitude, indicating a probable data base input data anomaly. The brine specifications that resulted from this procedure and were subsequently used as input for the FLOSCAL computations are summarized in the second column of Table 3.

Results of the FLOSCAL Simulation A FLOSCAL simulation was set up to follow the brine flow through the series of six heat exchangers. A summary of the important input parameters used in the simulations is given in Table 3. The assumed brine temperature profile and pressures were specified in the input. The pressures were arbitrarily specified at values sufficient to keep the brine subcooled.

Assumed Operating Conditions	
Brine Supply Temperature	182.2°C
Brine Supply Pressure	24.8 Bar
Brine Flowrate	10.87 kg/sec
Brine Outlet Temperature	73.9°C

Assumed Geometry	
No. of H.X. Modules	6
No. of Tubes/Bundle	62
Total Tube Length	45.15 m
Tube Hydraulic Diameter	.01575 m
Flow X.S. Area/Bundle	.01276 m^2
Material	Carbon Steel

Table 3 Summary of FLOSCAL Input Parameters and Geometry Specifications

The primary results of the FLOSCAL simulations of the PSEMT facility are summarized in Figures 2 and 3. Salient results and observations drawn from these simulations are as follows:

1. Figure 2 shows the minerals predicted to exceed saturation as a function of temperature and location in the heat exchanger. The number of predicted precipitates is relatively small.

2. In Figure 3 it is shown that corrosion as FeS_2 was predicted to occur at a corrosion product formation rate ranging from 0.1 mm per year at entry to 0.014 mm per year at exit.

3. The predictions showed that the FeS_2 solubility limits were exceeded in the three lower temperature (brine side) heat exchangers. However, the small quantity of iron present (due to excessive depletion of iron in the EQUILIB initialization sequence) and currently used rate constants resulted in predictions of infinitesimal amounts of FeS_2 precipitate.

4. The net rate of mineral precipitation was negligible compared with the predicted accumulation rate of corrosion products. The brine quickly dropped below saturation with respect to Witherite $BaCO_3$, after heat exchanger entry. Quartz solubility was exceeded, but the amorphous silica solubility was not. Slow deposition kinetics prevented significant quartz deposition.

5. The brine was saturated with respect to Minnesotaite $Fe_3Si_4O_{10}(OH)_2$ at the inlet but rapidly fell below saturation in the heat exchanger. This was probably due at least in part to the apparently excessive depletion of iron as $Fe_3Si_4O_{10}(OH)_2$ in the EQUILIB sequence.

6. Brine pH dropped from 6.1 at the hot end to about 5.7 at the low temperature end.

Conclusions Drawn from the PSEMT Simulation A suspected inaccuracy of the data base caused anomalous iron loss in equilibration at reservoir conditions. It seems to be important to improve on iron equilibrium constants. It is of interest whether Minnesotaite is a plausible candidate for removal of some of the iron in flashing situations.

The FeS_2 precipitation may have been underpredicted by the code, due to an excessive activation energy and to the small amount of iron left in the brine after reservoir equilibration.

No evidence was found of precipitation problems of any significance from the Magma East Mesa brine in binary plants. Corrosion is far more important.

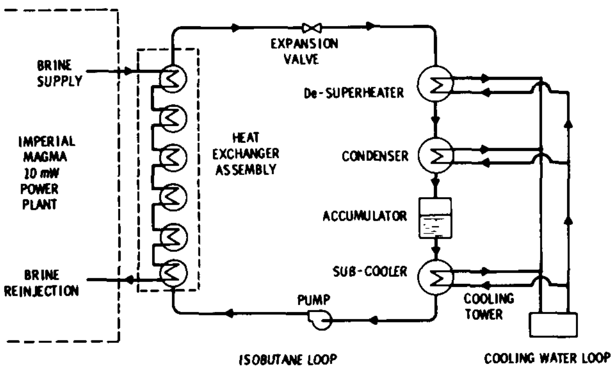

FIGURE 1 Schematic of the PSEMT Facility

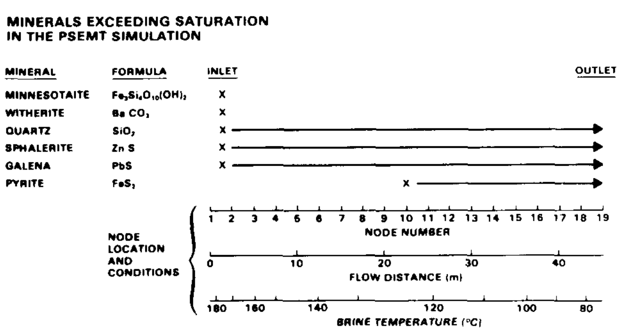

FIGURE 2 Map of Minerals Precipitated by PSEMT

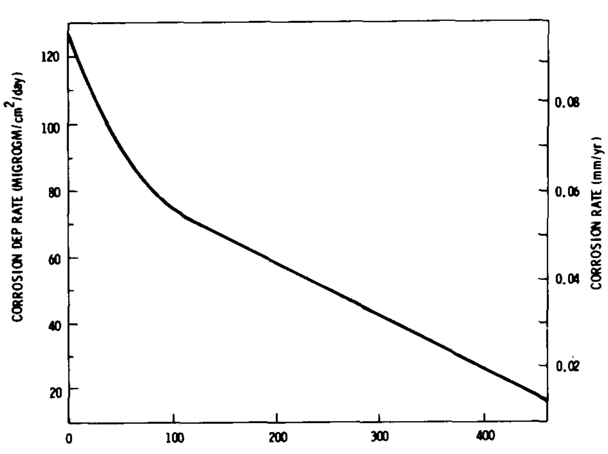

FIGURE 3 Predicted Corrosion in PSEMT

2. SCE Heber Flash Plant Simulations were performed of a 50 MW_e flashed steam geothermal power plant that has been proposed by the Southern California Edison Company (SCE) for construction at a site near Heber, CA. A simplified schematic of the facility modeled is given in Figure 4. The simulations were performed using the EQUILIB, WELL and FLOSCAL computer codes.

Two computational sequences were performed to simulate potential design and operational alternatives to illustrate the effect of varying brine quality on scaling in the plant. Although the analysis was primarily concerned with scale that may be expected in the plant, consideration was also given to scaling that would occur in the wells and transmission lines for the two simulated operating conditions.

Description of the Proposed Plant The proposed geothermal power plant would be a two-stage flashed steam design with a net electrical output of 50 MW. Brine will be provided by Chevron from a number of wells with a nominal reservoir temperature of about 182°C. Two-phase brine will be provided to the plant with a quality of less than 8% at a pressure of about 4.1 bar (60 psia).

The first flash/separator vessel will function primarily as a separator with only slight additional pressure drop and flashing. The brine extracted from the separator will be flashed again to 16 psia in the second flash vessel. The steam from the two flash vessels will be expanded in two stages in a "conventional" low pressure turbine generator, condensed, combined with the spent brine from the second flash vessel and reinjected.

Brine Specifications Brine data were not available for the specific wells that will be used to supply the plant. It was, therefore, necessary to hypothesize a model brine which could be assumed to be representative of an actual Heber brine. For this purpose the Nowlin #1 (6) well was selected as being "typical" of wells that might be used. Essentially the same data were used in establishing a model brine used in prior simulations of the 2000 hr heat exchanger tests at Heber. (6)

The resulting model brine specifications at the sample temperature of 25°C are summarized in the first column of Table 4. These data constitute the starting point for back-calculation of the brine to the simulated reservoir conditions. The significant changes that occurred due to mineral equilibration at well bottom conditions are summarized in the second column of Table 4. The other species concentrations were essentially unaltered.

a. Aqueous Species in Solution (Moles/kg Brine)

Element	Sample	After Mineral Equilibration
Al	$.259 \times 10^{-4}$	$.841 \times 10^{-6}$
K	$.831 \times 10^{-2}$	
Na	.187	
Ca	$.229 \times 10^{-1}$	
Mg	$.823 \times 10^{-5}$	
Fe	$.895 \times 10^{-5}$	$.126 \times 10^{-5}$
Mn	$.728 \times 10^{-5}$	
Pb	$.490 \times 10^{-5}$	$.436 \times 10^{-6}$
Zn	$.780 \times 10^{-5}$	$.105 \times 10^{-5}$
Cu	$.629 \times 10^{-6}$	$.253 \times 10^{-6}$
Si	$.422 \times 10^{-2}$	$.345 \times 10^{-2}$
As	$.280 \times 10^{-5}$	
SO_4	$.614 \times 10^{-3}$	
CO_3	$.409 \times 10^{-2}$	
Cl	.227	
H	$.316 \times 10^{-5}$	
NH_3	$.587 \times 10^{-3}$	
F	$.105 \times 10^{-3}$	
BO_3	$.740 \times 10^{-3}$	
Ba	$.313 \times 10^{-4}$	
Sr	$.434 \times 10^{-3}$	
Sb	$.287 \times 10^{-4}$	
(pH)	(5.50)	(5.38)

b. Brine Gas Analyses

Gas	Partial Pressure (Bars)
H_2S	.0039
CO_2	.579
HCl	0
S_2	0
O_2	0
H_2O	.0317
H_2	.0154
NH_3	0

Table 4 Heber Brine and Gas Analyses Used in Simulation of the SCE Plant

Computational Sequence A summary of the physical dimensions and other data used in the simulations is provided in Table 5 and in Figure 4. Flow rates, pipe diameters, and flash vessel dimensions were provided by SCE. Pipe lengths in the plant were not generally specified so that the values chosen were somewhat arbitrary.

Design or Operating Parameter Description	Metric Units
Geothermal Wells:	
Reservoir Temperature	182°C
Number of Wells	
Well Diameter	.46 m
Calc. Depth of Flash	280 m
Total Brine Flowrate	3.66×10^6 kg/hr
Wellhead Pressure	5.5 bar
Wellhead Quality	
Brine Transmission Pipe:	
Diameter	1.22 m
Total Length	164 m
Plant Brine Lines (2 Parallel Systems):	
Diameter	.91 m
Length	48 m
Inlet Pressure	4.1 bar
Inlet Quality	
First Flash/Separator Vessel:	
Outside Shell Diameter	30.5 m
Inside Pipe Diameter	.81 m
Overall Length	6 m
Inlet Pressure	3.86 bar
Internal Pressure	3.79 bar
Second Flash Vessel:	
Inlet Pipe Diameter	.61 m
Inlet Pipe Length	32 m
Outside Shell Diameter	3.66 m
Inside Pipe Diameter	1.07 m
Overall Length	6 m
Inlet Pressure	3.51 bar
Exit Pressure	1.10 bar

TABLE 5 Summary of Primary Design and Operating Specifications for the SCE-Heber Geothermal Plant

Establishing the brine chemistry at the inlet to the plant involved the following steps:

1) After inserting all species at concentrations determined from the sample data, Table 4, EQUILIB was used to perform a charge balance for the brine at 25°C using Na^+ as the charge variable.

2) An equilibrium reservoir chemistry was then generated using EQUILIB by requesting mineral equilibrium at reservoir conditions.

3) The WELL code was used to establish temperature, pressure, and quality profiles in the well, determining the location of the onset of flashing.

4) These profiles and reservoir chemistry from EQUILIB were used as input to a FLOSCAL simulation of the well. This established wellhead chemistry and quality for an imposed 80 psia wellhead pressure.

5) The pressure was then dropped from 5.5 bar (80 psia) to 4.1 bar (60 psia) over 164 m (500 ft) of brine collection pipe (48" diam). The pressure, temperature, quality, and scaling rates were computed in the pipe up to the plant inlet.

6) The brine chemistry predicted by FLOSCAL at the end of the 164 m (500 ft) pipe was used as input for simulating fluid conditions and scaling rates in the actual SCE plant piping and flash vessels.

Flowstream simulations were run using FLOSCAL to predict thermal and fluid mechanical conditions and the rates of mineral scaling and corrosion throughout the entire brine flow path from the reservoir to the outlet of the second flash vessel.

A simulation was run first of the nominal design with flashing wells. The results of this simulation indicated very little scale would form in the plant. A second simulation was then run where it was assumed that the wells were pumped to a pressure sufficient to deliver the brine to the plant in a compressed liquid state. In this case the initial flashing occurred at the inlet to the first flash/separator vessel where the vessel pressure and subsequent conditions were assumed to be the same as in the initial simulation. This simulation was essentially a "worst case" calculation of the potential effect of reducing the quality of the brine received by the plant by reducing the degree of upstream flashing.

Summary of Results The primary results of the simulations are presented in Figures 5 and 6. Some observations drawn from these and other results of the simulations may be summarized as follows:

- For the nominal design conditions (Figure 5) flashing was predicted to occur in the well with the maximum rate of calcite deposition (about 1 mm/wk).
- Additional calcite scaling was predicted to occur at a diminishing rate throughout the remainder of the well and transmission lines, in the first flash vessel (.011 mm/wk) and in the pipe connecting the first and second flash vessels (.017 mm/wk).
- No additional calcite scale was predicted to occur in the second flash vessel for the proposed operating conditions.
- For the second computational sequence (Figure 6) the brine was delivered to the plant in a compressed state with no flashing and, therefore, no calcite scaling predicted in the wells or transmission lines. However, the rate of calcite scaling was increased to .18 mm/wk in the first flash vessel.
- The scaling rate in the .6 m (24 inch) pipe increased to about .32 mm/wk. As in the first case, calcite scaling was not predicted to occur in the second flash vessel.
- The predicted rate of scale deposition due to the precipitation of other minerals (primarily metal sulfides and quartz) was insignificant compared to the rate of deposition of calcite.
- Scale formation due to corrosion was predicted to occur at low to moderate rates throughout the system for both simulations. At locations preceding the flash, the predicted corrosion species was pyrite FeS_2 whereas, following the onset of flashing, the predicted corrosion species was magnetite Fe_3O_4. The maximum predicted rate of corrosion (about .3 mm/yr of steel) occurred in the well immediately downstream of the flash.

Conclusions Drawn from the Heber Plant Simulation The principal conclusions that can be drawn from these simulations may be summarized as follows:

- The most serious calcite scaling and corrosion problems can be expected to occur immediately downstream of the initial flash, wherever that might be.
- In the first case calcite scaling in the first flash vessel was predicted to be moderate but probably sufficient to require some level of scale mitigation or maintenance measures.
- For the second case where initial flashing occurred in the first vessel, substantial scaling can be expected in the flashing orifice or valve, in the interior of the first flash vessel, and in the pipe connecting the first to the second flash vessel. Substantial scale mitigation or maintenance measures would probably be required.

* Based on the predictions, scaling is not expected to be a problem in the second flash vessel for either operation simulated.

* Although corrosion was predicted to occur throughout the system, the rates were sufficiently low that no major problems related to corrosion should be anticipated.

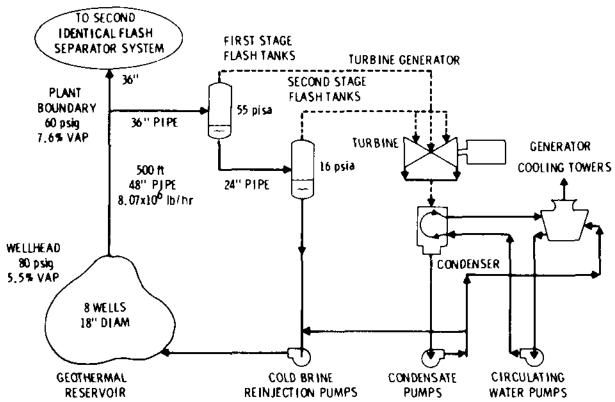

FIGURE 4 Schematic of the Heber Plant

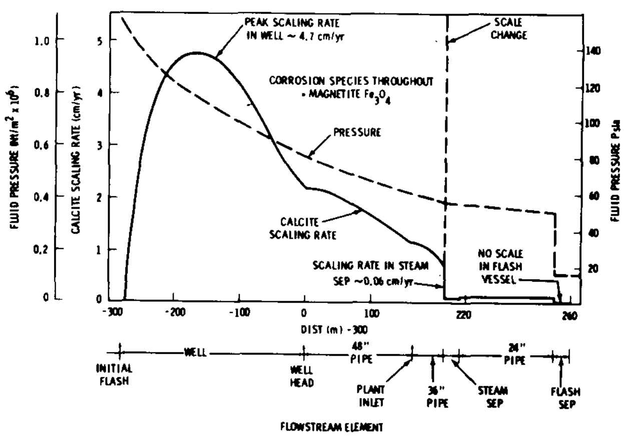

FIGURE 5 Predicted Scale Distribution for SCE Plant with Flashing Wells

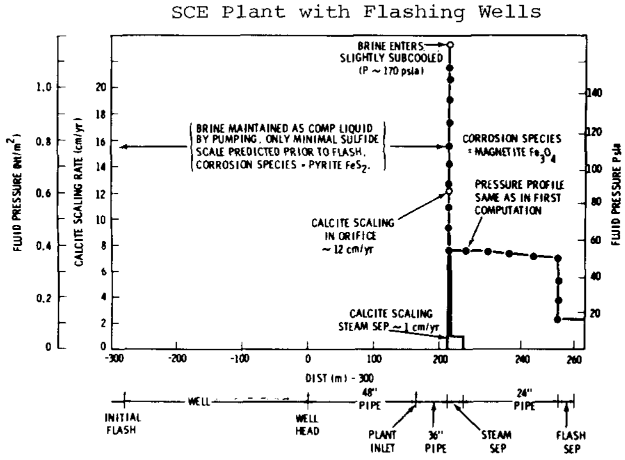

FIGURE 6 Predicted Scale Distribution for SCE Plant with Pumped Wells

3. Simulation of Scaling Due to Flashing Flow in a Porous Medium A simulation was performed of an experiment conducted by Republic Geothermal Inc. (RGI) (7) in which flowing brine was flashed in a porous medium due to frictional pressure drop. The WELL and FLOSCAL codes were first used to generate profiles of velocity, quality, temperature, and pressure through 3.3 cm of sand, through which the brine flowed because of a 7 bar pressure drop to atmospheric pressure. FLOSCAL then predicted calcium carbonate deposition to occur in the sand formation, in good agreement with experiment.

Description of the Test Facility The experimental configuration is shown in Figure 7. The porous medium consisted of granular material in a test cartridge with a perforated bottom. The pressure in the subcooled liquid above the granular material was maintained at 8 to 10 kg/cm^2 ($\sim$10 atm) during runs whose duration was on the order of 2 to 5 hours.

The mass deposited was determined from weighings of the cartridges before and after the runs, and also from the upstream and downstream brine calcium analyses. The distributions of $CaCO_3$ were determined by infusing epoxy into the granular media, sectioning, and examining under a microscope.

A number of runs were performed in which size of granular material, permeability, roundness, composition, uniformity, and run duration were varied. The present study simulated a single run designated Sand No. 3 Cartridge 13 (3-13). This run used sand as the porous medium, with a median grain size 0.28 mm and a distribution of sizes from 0.14 mm to 0.59 mm. Run duration was 3.73 hours, during which 620 kg of fluid was transmitted. The granular medium was of 3.3 cm extent in the flow direction and 47.7 cm^3 volume, so the average cross-sectional area was 47.7/3.3 or 14.45 cm^2 and the average cup diameter about 4.29 cm. As shown in Figure 7, the cup cross-section tapered slightly toward its perforated bottom. Stated bed porosity was 0.35.

Brine Characterization Chemical analysis reports (7) were supplied by RGI on samples cooled without flash from well 56-30. The analysis was performed by Vetter Research with supplementary measurements of calcium and bicarbonate ion concentrations made by RGI.

The analyses were also supplemented by analyses from J. C. Watson and O. J. Vetter performed under a U.S. Department of Energy, Division of Geothermal Energy Study (8).

A brine description for input to the EQUILIB or FLOSCAL codes was obtained by averaging the values reported on the RGI data sheets for most variables. The input values are summarized in the first column of Table 6.

a. Sample and Equilibrated Species Concentration (moles/kg Brine)

Species	Sample	Changes after Mineral Equilibration
K^+	$.1189 \times 10^{-2}$	
Na^+	$.2588 \times 10^{-1}$	
Ca	$.1472 \times 10^{-3}$	
Fe^{+2}	$.1656 \times 10^{-5}$	$.132 \times 10^{-8}$
Si	$.2385 \times 10^{-2}$	$.215 \times 10^{-2}$
S^{-2}	$.1560 \times 10^{-5}$	
S^{+6}	$.1874 \times 10^{-2}$	
C	$.1723 \times 10^{-1}$	
Cl	$.1509 \times 10^{-1}$	
H^+	$.6125 \times 10^{-6}$	
NH_3	$.1136 \times 10^{-3}$	
F	$.1211 \times 10^{-3}$	
B	$.3839 \times 10^{-4}$	
Sr	$.4622 \times 10^{-5}$	$.756 \times 10^{-5}$

b. Minerals Precipitated at Reservoir Conditions (moles/kg Brine)

Minerals	Amount Rejected
Quartz SiO_2	0.237×10^{-3}
Strontianite $SrCO_3$	0.207×10^{-5}
Goethite $HFeO_2$ or FeO(OH)	0.1655×10^{-5}

Table 6 Brine Description for East Mesa Well 56-30

An EQUILIB run was performed with brine information from Table 6 to generate an equilibrium brine at 158.3°C reservoir temperature. Mineral equilibration was requested, with brine pH held fixed at 6.48 and redox state calculated to be consistent with the input sulfide/ sulfate ratio.

The resulting concentrations of species precipitated are given in the second column of Table 6. Minerals precipitated in coming to a complete equilibrium at reservoir temperature were quartz, strontianite, and goethite. The strontianite $SrCO_3$ precipitation reduced the strontium content 45% from the input value, though the change in the total aqueous carbon was negligible. This probably indicates that the brine was in equilibrium with strontianite in the reservoir.

In this simulation, as in several others, the iron content of the brine at reservoir conditions was reduced dramatically by precipitation (in this case, of goethite FeO(OH)). This may indicate inaccurate or missing data in the data base and/or input data. Although these iron concentration considerations are important in systems in which iron sulfides, silicates, and corrosion are the dominant surface degradation effects, they are not important for the effects calculated in the present porous medium flash simulation.

The quantity of silica removed due to deposition of quartz was insignificant. All other species concentrations were essentially unchanged.

Fluid Dynamics and Scaling Simulations To set appropriate boundary conditions for the fluid dynamics solution it was reasoned that the brine pressure at exit from the granular medium cup bottom was either very near atmospheric, or was at some higher value determined by a choked flow condition. The solution procedure consisted of iteratively determining an "effective" hydraulic diameter that satisfied the specified boundary conditions and resulted in one or the other of these conditions.

A two-stage approach was employed in the FLOSCAL simulation:

1. Iteratively determine brine transmission characteristics of the porous medium to match specified boundary conditions.

2. Simulate full chemistry deposition kinetics in the two-phase region of the flow, using the calculated flow distribution from Step 1.

The first stage employed an NaCl brine of total molality equivalent to the actual brine. The second stage used the "best estimate" representation of the well 56-30 brine and a twenty node flowstream representation. A summary of the input variables used in the flowstream simulation is given in Table 7.

pH at start	6.48
Pressure at start	5.953 bars
Temperature at start	158.02°C
Mass flow rate	0.04617 kg/sec
Quality at start	0
Hydraulic diameter	7.6031×10^{-6} m
Cross sectional flow area	5.059×10^{-4} m^2
Roughness parameter	0

Table 7 FLOSCAL Input for Simulation of Scale Deposition Kinetics in the Last 1.1 cm of Granular Medium in RGI Experiment Sand #3 Cartridge 13

Figure 8 shows plots of the computed pressure, temperature, quality and velocity as a function of distance from the entry face for the run whose input hydraulic diameter gave the exit pressure closest to atmospheric. The onset of flash occurred at approximately 2.2 cm into the granular medium from the front face or 1.1 cm from the rear face. The quality rose to about 11% at brine exit. The linear velocity rose rapidly as the brine quality increased. An exit interstitial velocity of about 17 meters/sec is shown, but changing the hydraulic diameter slightly can alter this value dramatically.

The sensitivity of calculated exit pressure and velocity to hydraulic diameter is shown by the following list of cases and results with the NaCl brine and the same mass flow rate.

Hydraulic Diam (meters)	Exit Pressure (bars)	Exit Velocity (m/sec)
7.6031×10^{-6}	1.0095	17.0
7.6008×10^{-6}	0.9397	18.9
7.5938×10^{-6}	0.7116	27.0

A somewhat lower hydraulic diameter will lead to sonic exit velocity (∿80 m/sec), but an exit pressure below atmospheric makes this unphysical for this particular experiment.

The effective hydraulic diameter determined in this simulation seems rather small, being only 1/30 of the mean particle diameter, 0.28 mm. It should be noted, however, that the stated end points of the size distribution of the sand were 0.14 mm and 0.59 mm. The smaller particles should wedge between larger ones, creating limiting constrictions much smaller than the mean particle size.

The most important scale prediction is that of calcium carbonate (labeled calcite), shown in Figure 9. The deposition rate is plotted in grams of $CaCO_3$ per unit of geometrical (rather than pore or particle) volume. The peak deposition rate was predicted at about 0.8 cm ahead of the granular medium exit face, compared with 0.3 cm observed. The calculated deposition shut off in the last millimeter from the exit, as did also the observed deposit. Predicted and observed deposition onset were both at about 1.1 cm from the exit face.

A peak deposition rate of 11.7 gm/cm^3 per day can be read from Figure 9. Using a density of 2.71 gm/cm^3 for calcium carbonate, one calculates that this rate would fill the spaces in a 35% porosity medium in 1.95 hours. The actual experiment ran 3.73 hours, during which the transmissibility of the cartridge dropped from 49.3 gm/sec per kg/cm^2 pressure difference to 16.3 gm/sec per kg/cm^2. Thus, a major part of the pore space had probably filled at the plane of peak deposition.

The total mass deposition predicted by FLOSCAL was 7.958 grams of $CaCO_3$ deposit during the 3.73 hour run. The experimentally determined weight gain of the cartridge was 2.3 grams, while the deposit deduced on a chemical basis was 3.44 grams.

One additional qualitative aspect of the predicted scale deposition phenomena is of interest. The calculated calcite and aragonite saturation indices predicted that the brine would become calcite-supersaturated first, with aragonite supersaturation occurring about 0.6 mm later. The first deposit observed in the cartridges was calcite, followed by a region of predominantly aragonite deposition nearer the exit face. The physical system shows no return to calcite deposition as the deposition rate slacks off, contrary to what the calculation predicted. It would thus appear that FLOSCAL does not always correctly distinguish between aragonite and calcite as the $CaCO_3$ deposition mineral.

<u>Conclusions Drawn from the Porous Media Flashing Simulation</u> This simulation supports optimism for the development of a satisfactory calcium carbonate deposition model and predictive capability for geothermal brines. The existing model was applied in a new Reynolds number region, and it functioned tolerably well. Insights for model improvement are accumulating from the diverse brine flash cases that have been modeled. Three areas for potential improvement on the calcium carbonate deposition model are emerging:

1. CO_2 dissolution and vaporization should be incorporated into the fluid dynamics calculation. This should be done to model formation of a CO_2-rich vapor phase at higher pressures than the water saturation pressure.

2. The molecular and ion transport sub-models should be improved in a) Reynolds number dependence, and b) representation of entry length and other localized flow phenomena.

3. The effects of slow conversion between unhydrated CO_2 and H_2CO_3 should be taken into account. EQUILIB currently treats both forms as H_2CO_3.

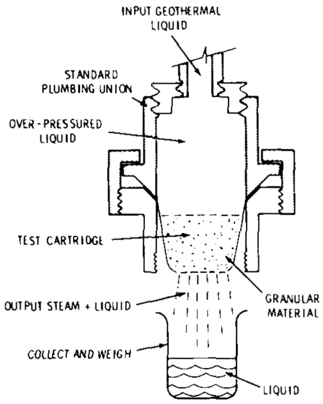

Figure 7 Schematic of Porous Plug Experiment

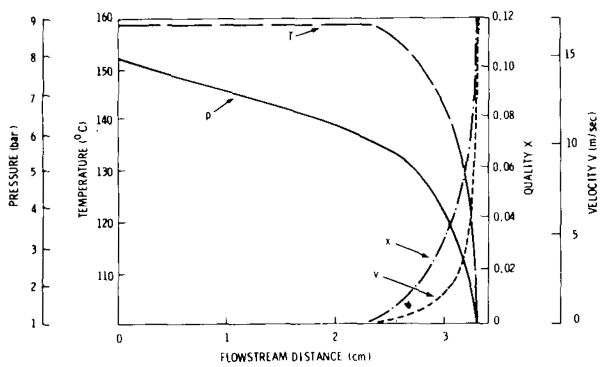

Figure 8 Predicted Conditions in Flashing Porous Plug

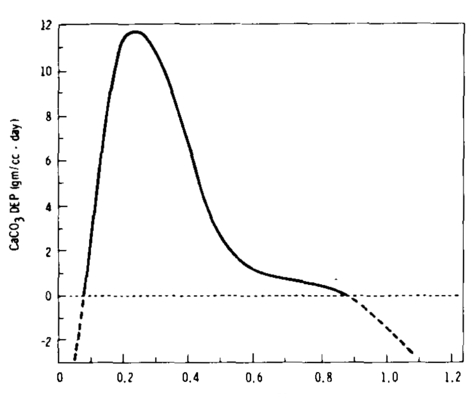

Figure 9 Predicted Scale Distribution in Porous Plug

4. Upstream H_2S Removal System Simulations were performed of the upstream H_2S removal process that is being investigated by Coury and Associates, Inc. for EPRI. Input steam conditions and variable quantities of H_2S, NH_3, and CO_2 were used in the simulations that are representative of The Geysers field. The effects of redox state and pH were also investigated. The primary output of the calculations was the H_2S removal efficiency as a function of input steam gas content and the final condenser quality.

Experimental Facility and Tests The upstream H_2S removal process is shown schematically in Figure 10. The inlet geothermal steam is mostly condensed on the shell side of a heat exchanger. A small fraction of the inlet steam flow, referred to as the vent fraction, is withdrawn and sent to an auxiliary waste gas treatment facility. The condensate is revaporized upon passing through the tube side of the heat exchanger, as shown in Figure 10. The steam contained in the vent gas is, of course, lost for useful purposes.

Experiments are being performed on a prototype system at The Geysers geothermal field. However, experimental results were not yet available for comparison with results of the current simulation.

Input Description and Model The computations were performed using EQUILIB in successive equilibrations with varying quality. To simplify this process, a fictitious flowstream comprising six flowstream segments was described in FLOSCAL input. Temperature and quality were specified at each segment. The quality at the first node was specified to be zero, and quantities of H_2S, CO_2 and NH_3 present in solution were specified there. At the other five nodes, temperature was specified at a constant value (350°F) typical of the entry side of the heat exchanger for The Geyser's field. The quality was specified at 2, 5, 10, 75 and 98%, respectively, at subsequent nodes. The resulting equilibrium partitions of H_2S, NH_3, and CO_2 between liquid and vapor phases at these qualities were then calculated by the code. If the condensation/gas absorption process may be assumed to approach a true equilibrium process and if the resulting vapor can be efficiently separated from the condensate, then the computed fraction of total sulfur as H_2S in the vapor phase is the fraction that should be removed.

The reported calculations were made with what is believed to be the best available equilibrium data for H_2S solubilities (9). However, additional calculations were also made with data derived from NBS circular 500, original source of H_2S data used in EQUILIB.

The main series of calculations featured all combinations of the H_2S, NH_3, and CO_2 concentrations shown in Table 8. The assumed temperature for condensation was 350°F (177°C).

Results of the Simulation Values of the calculated fraction of the total sulfur present as vapor phase H_2S (i.e., in the vent gas) are presented in Table 9 and in Figures 11 and 12. From these results, it can be seen that the parameter that most

Species	Concentrations, ppm by mass		
H_2S	115	230	460
NH_3	50	170	300
CO_2	3000	8000	

Table 8 Concentrations in Total Flow Used in the H_2S Removal System Simulation

affects the H_2S removal efficiency in this process is the condenser quality (or gas vent fraction). However, the effect of ammonia on H_2S removal was also found to be significant.

For condensation of 98% of the incoming gas flow (2% vent), the fraction of the total sulfur remaining as vapor phase H_2S is shown in Table 9 to vary from 68 to 78%. Condensation of 90% of the incoming mass flow left 86 to 93% of the total sulfur in the vapor phase for rejection to the H_2S treatment plant. The assumed fraction of total flow rejected as gas to the cleanup plant was thus found to be critical to the H_2S removal efficiency. This is also evident in Figure 11. The fraction of total flow vented is also crucial to the energy penalty inherent in this process. An attempt to minimize the energy penalty by minimizing the amount of rejected gas would result in lower H_2S removal efficiency. Thus, compromise operating conditions would have to be found.

The trends in the H_2S removal performance with NH_3 concentration are shown in Figure 12. Ammonia present tends to reduce H_2S removal efficiency. However, the removal efficiency does not depend very strongly on the amount of H_2S present. The presence of CO_2 was found to have relatively little effect on the H_2S removal efficiency.

Some additional observations relevant to the findings of this study may be summarized as follows:

- The predicted H_2S removal fraction was relatively insensitive to H_2S concentration in the inlet steam. However, the H_2S removal efficiency was found to be sensitive to the thermodynamic equilibrium relations employed for H_2S liquid/H_2S gas and H_2S liquid/HS^- liquid. Equilibrium relations used in the present study predict significantly less effective H_2S removal than do values from NBS Circular 500. However, calculations based on the Circular 500 data were in good agreement with those reported by Coury.

- Predicted H_2S removal efficiency decreased with increasing pH of the condensate. This occurred largely because increasing the pH increased the fraction of HS^- in the liquid. Ammonia in the liquid increased pH and thus reduced H_2S removal fraction. CO_2 present improved H_2S removal very slightly, primarily by slightly lowering the pH. The improvement in H_2S removal performance from reducing the pH became negligible after the pH dropped below about 5.

Conclusions Drawn from the H_2S Removal System Simulation The results of the simulation of the H_2S removal technique were not generally very encouraging. The calculations indicate that achievement of an acceptable level of H_2S removal may require excessive vent gas rates and the accompanying reduction in cycle thermal efficiency. However, the predicted H_2S removal efficiency was shown to be very sensitive to the equilibrium data used for H_2S. In addition, kinetic effects that might be relevant to the process were not considered. Thus, these results should probably be treated as tentative, pending experimental verification.

Case No.	Vapor Composition ppm by weight NH_3	H_2S	CO_2	Fraction of Total Sulfur in Vapor Phase H_2S 15% Quality	10% Quality	5% Quality	2% Quality
1	50	115	300	0.931	0.914	0.866	0.755
2	170	115	300	0.906	0.885	0.826	0.702
3	300	115	300	0.890	0.864	0.798	0.667
4	50	230	3000	0.943	0.925	0.876	0.764
5	170	230	3000	0.924	0.900	0.840	0.716
6	300	230	3000	0.910	0.883	0.815	0.683
7	50	460	3000	0.951	0.933	0.884	0.773
8	170	460	3000	0.936	0.912	0.854	0.732
9	300	460	3000	0.925	0.898	0.833	0.703
10	50	115	8000	0.930	0.916	0.874	0.770
11	170	115	8000	0.911	0.893	0.845	0.732
12	300	115	8000	0.899	0.878	0.824	0.706
13	50	230	8000	0.941	0.924	0.880	0.774
14	170	230	8000	0.925	0.905	0.853	0.739
15	300	230	8000	0.915	0.892	0.834	0.714
16	50	460	8000	0.947	0.930	0.885	0.779
17	170	460	8000	0.934	0.914	0.861	0.746
18	300	460	8000	0.925	0.902	0.844	0.723

Table 9 Summary of Results for the H_2S Removal System Simulation

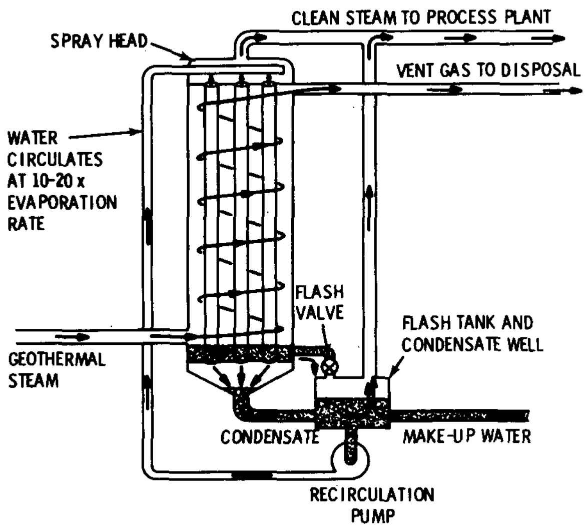

Figure 10 Schematic of the H_2S Removal System

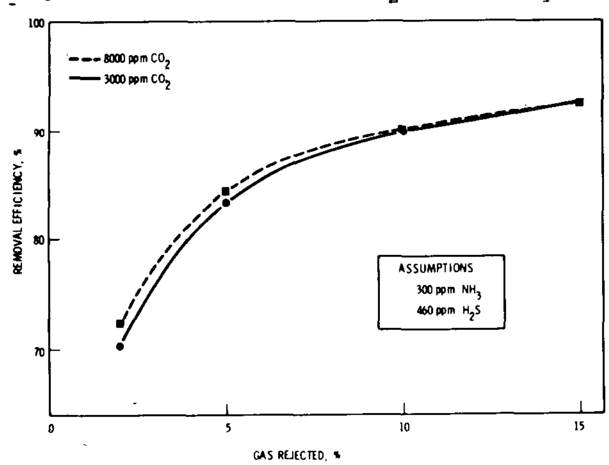

Figure 11 Predicted H_2S Removal Efficiency as a Function of Vent Gas Fraction and CO_2 Content

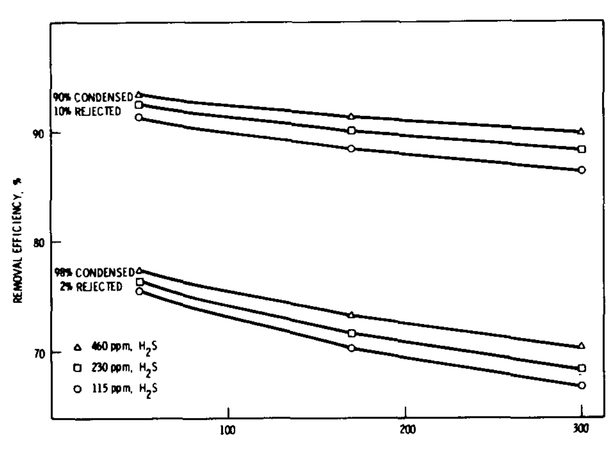

Figure 12 Predicted H_2S Removal Efficiency as a Function of Concentration NH_3 and H_2S

SUMMARY The results presented in this paper illustrate applications of the EPRI geothermal scaling codes to simulation of scaling in systems varying widely in physical scale, governing phenomena and function. The applications and primary findings were as follows:

1. PSEMT Simulation of a single-phase brine/hydrocarbon heat exchanger. Major scale was iron sulfide corrosion with minor amounts of other metal sulfides.

2. Heber Plant Simulation of brine path components including wells, collection/transmission lines, steam separator and flash vessel. Major scale was calcite primarily in wells and lines. Very little scale was predicted to form in the plant for normal operating condition.

3. Porous Media Simulation of laboratory scale experiments of flashing flow of brine in a porous plug made of sand. Predictions of calcite scale quantity and location were in good agreement with experimental results.

4. H_2S Removal System Simulation of a condenser/reboiler used to extract gases from geothermal steam. Predictions showed H_2S removal efficiency to be most dependent on vent gas removal rate and to a lesser degree on NH_3 content.

Although very few experimental results were available for comparison with the simulations, the results were generally plausible and informative. For the porous media case, agreement with experiment was considered good. The results of the cases evaluated to date give confidence that the codes function as intended in a wide range of applications, and that the results are, in general, qualitatively correct. The best quantitative accuracy has been obtained for predictions that result primarily in calcite scaling. The prediction of sulfide scale has been less successful. It is suspected that the accuracy of the predictions is currently limited by inaccuracies or omissions of data in the chemical data base. As the codes are more widely used, the completeness and accuracy of the data base will doubtless be improved.

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EPRI MOBILE GEOTHERMAL CHEMICAL ANALYSIS TRAILER

CONTRACT NO. RP741-1

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The EPRI Mobile Geothermal Chemical Analysis Trailer, fabricated by the Energy Systems Group of Rockwell International, is a modern well-equipped chemical analysis laboratory. This mobile laboratory, sketched in Figure 1, has complete capability for sampling of geothermal fluids and analysis of brine, steam, and noncondensible gases. The objective of the laboratory is to provide accurate onsite chemical analyses in a timely manner that results in preservation of the sample integrity and the efficient implementation of a test program.

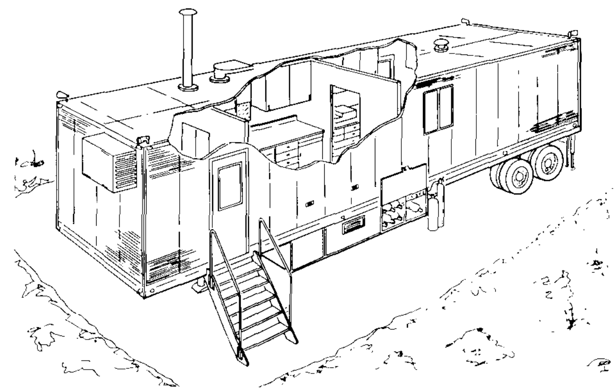

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Figure 1 Chemical Analysis Trailer — EPRI Mobile Geothermal Laboratory

The laboratory is built on a standard 40-ft truck trailer bed. The trailer chassis has been modified to carry requisite gas cylinders, compressor, and vacuum pump equipment in undercarriage bins, and has been equipped with air-ride shock absorbers to minimize road vibrations. A schematic of the instrument and equipment installation layout is shown in Figure 2. A list of analytical instruments and ancillary equipment is shown in Tables 1 and 2. The

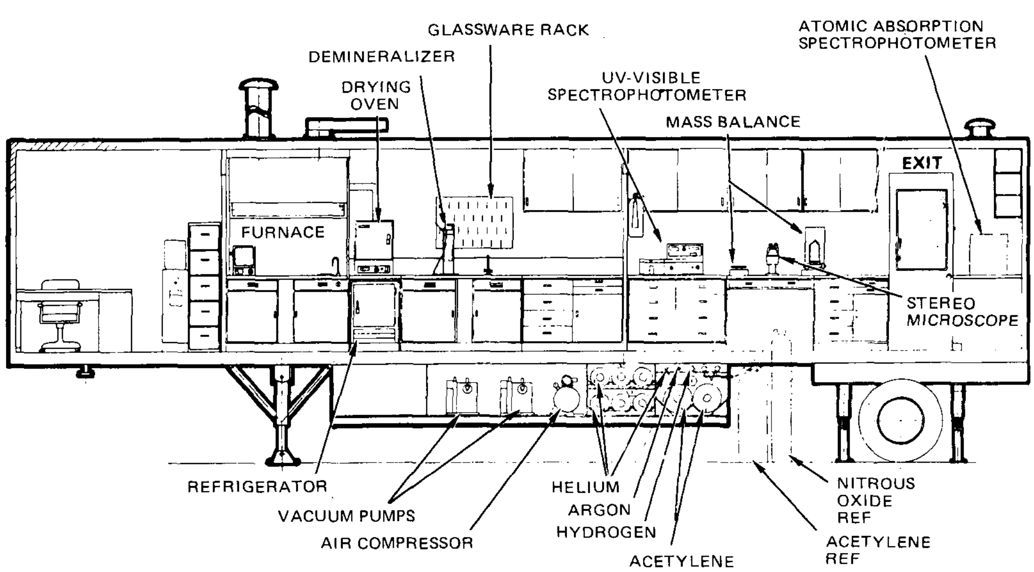

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Figure 2 EPRI Mobile Geothermal Laboratory — Side View

TABLE 1

MAJOR ANALYTICAL CHEMISTRY EQUIPMENT FOR CHEMICAL ANALYSIS

Equipment	Test Capability
Atomic Absorption Spectrophotometer	Analysis of the Cation Species: Al, As, Ag, Ba, B, Ca, Co, Cr, Cu, Fe, Hg, K, Li, Mg, Mn, Mo, Na, Ni, Pb, Si, Ti, V, Zn
Uv-Visible Spectrophotometer	Colorimetric Analysis: NH_4^+, Br, F^-, I^-, $S^=$
Coulometric Chloride Meter	Chloride Ion Measurement
Automatic Titrating System	Analysis of Total Alkalinity, Carbonate-Bicarbonate
Dissolved Oxygen Meter	Measurement of Dissolved Oxygen
Gas Chromatographic System	Analysis of Noncondensible Gases: CO_2, O_2, H_2, H_2S, N_2, SO_2, CH_4, Hydrocarbons
pH, Specific Ion Meter	Measurement of pH and Redox Potentials; Specific Ion F^-, NH_4^+
Fluid Sampling System	Sampling Noncondensible Gases, Steam and Geothermal Brine

TABLE 2

MAJOR ANALYTICAL CHEMISTRY EQUIPMENT REQUIRED FOR PHYSICAL PROPERTY MEASUREMENT

Equipment	Test Capability
Balances	
Analytical — 200 g ± 0.2 mg	Weighing for Chemical Analysis and corrosion 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
Conductance Meter	Conductance measurements on liquid samples for correlation to total dissolved solids content
Drying Oven	For moisture content, total dissolved solids
Stereomicroscope	Microscopic examination of samples

cation, anion, and gaseous species that can be analyzed are shown in Table 3.

Figures 3a through 3d are photographs of the completed laboratory.

After completion of fabrication, all systems, electrical, plumbing, fire alarm, etc., were inspected and operationally checked. In addition, the instrumentation and the analytical methods were checked and calibrated. The final test of the trailer was a field demonstration test. This field test was necessary to demonstrate that the

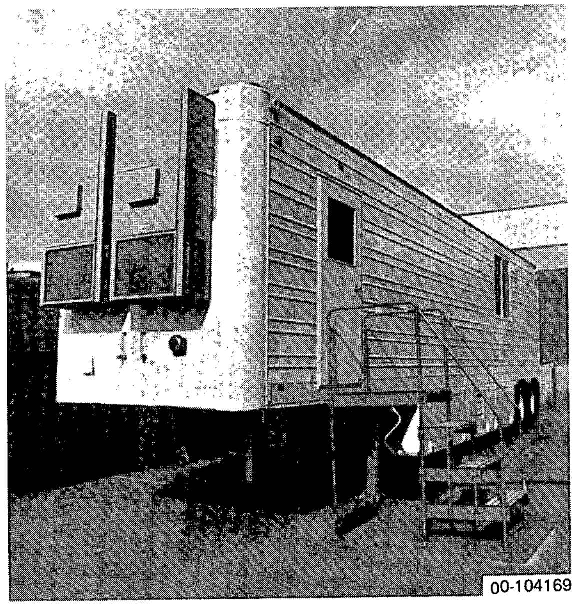
TABLE 3

GEOTHERMAL FLUID CHEMICAL SPECIES ANALYTICAL CAPABILITIES

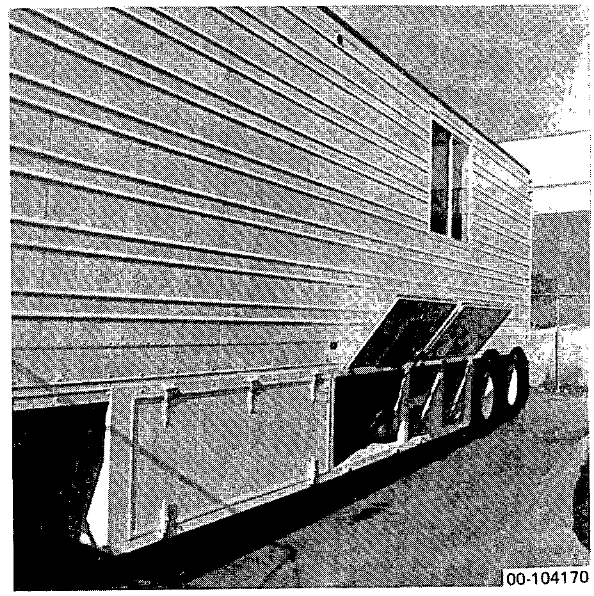
A. Analysis of the Cation Species: Al, As, Ag, Ba, B, Ca, Co, Cr, Cu, Fe, Hg, K, Li, Mg, Mn, Mo, Na, Ni, Pb, Si, Sn, Ti, V, Zn, NH_4^+

B. Analysis of Anion Species: Br, Cl, HCO_3, CO_3, F, I, S, SO_4

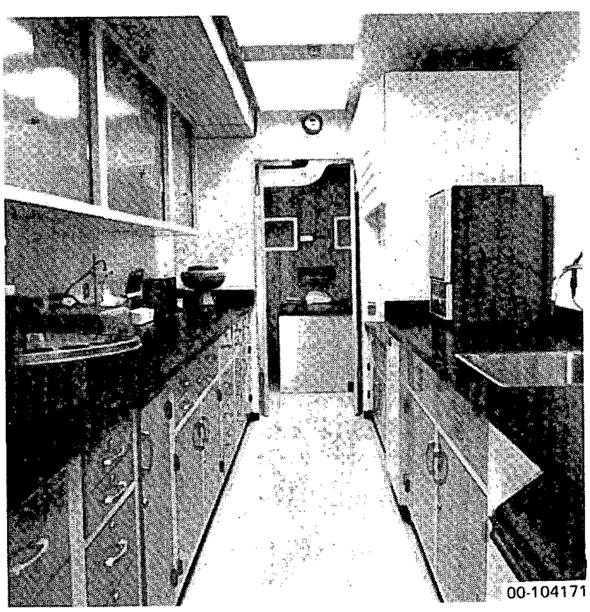
C. Analysis of Noncondensible Gases: CO_2, O_2, H_2, H_2S, N_2, SO_2, CH_4, NH_3, HC's



a. Exterior



b. Auxiliary Equipment — Gas Cylinder Storage Area



c. Interior — Lab and Office Areas

d. AAS Unit and Other Instruments

Figure 3 EPRI Chemical Analysis Trailer

mobile laboratory could be packed up, transported, set up, and placed back into operation. It provided a test of the instruments' shock mounting, the trailer's air-ride suspension, glassware and reagent packing, etc., i.e., a test of the general transportability of the entire system. Although the Fluid Sampling System (FSS) had been flow and leak checked, it was important to test the unit under the temperature, pressure, and scaling conditions of an actual geothermal well. More than a capabilities demonstration, the field test allowed otherwise hidden or unforeseen problems to be detected and corrected.

The field demonstration test was conducted at the U.S. Department of Energy Geothermal Test Facility at East Mesa, California which is located ∿250 miles from the fabrication site. None of the equipment was damaged in transit. The only major problem encountered was a clogged valve in the gas chromatograph which prevented analysis of the noncondensible gas. This problem was found by the supplier to be a manufacturing defect.

Samples were taken from Well 8-1 using the fluid sampling system provided with the trailer. The Fluid Sampling System (FSS) shown schematically in Figure 4 is a lightweight portable system which does not require electric power or running water. It may be used to collect samples by reducing pressure and temperature in either order.

Figure 5 is a photograph of the FSS connected to the well. The properties of the well obtained with the FSS are given in Table 4. Chemical analyses results of the flashed brine are given in Table 5.

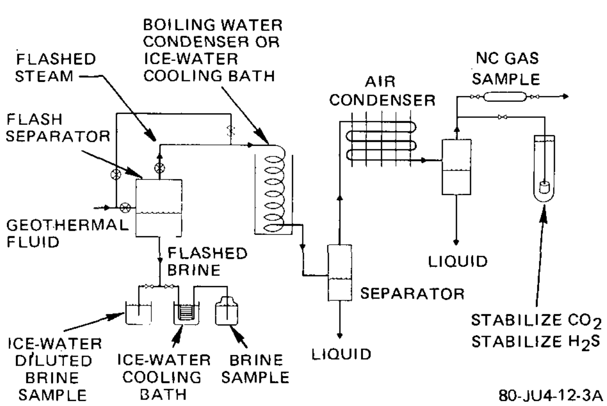


Figure 4 Fluid Sampling System

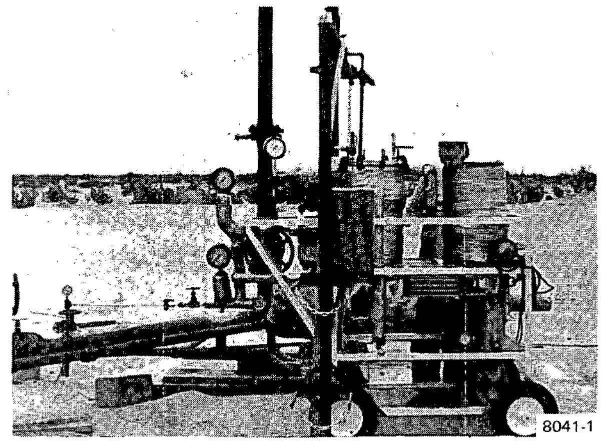


Figure 5 Photograph of Fluid Sampling System

TABLE 4

EAST MESA WELL 8-1 BRINE PROPERTIES

	Date	
	4-25-80*	4-27-80
Temperature (°F)		
Initial	320	319
After throttling	226	235
Pressure (psia)		
Initial	323	323
After throttling	20	24
Flow (lb/h)		
Brine	46.9	39.7
Condensate (steam)	3.58	3.05
NCG (Mole %)	0.04	0.04
Steam Fraction	7.1%	7.1%
T.D.S.†	3884	3846
Enthalpy (Btu/lb)		
Brine at wellhead conditions	290	290
Calculated from flashed brine and condensate enthalpies	263	270

*Unstable flows.
†Calculated from TDS values of flashed brine and condensate.

A comparison of results on the brine with that obtained by the site operator (Westec Services, Inc.) is given in Table 6.

The two brine samples were collected in a similar manner by reduction of the temperature to ambient followed by reduction of the pressure to atmospheric. A comparison of the results shows that

TABLE 5

WELL 8-1, COMPOSITION OF FLASHED BRINE

Analyte	As Collected	Corrected for Steam Loss
pH	8.91	
Conductivity (μmho/cm)	6750	6237
NH_3 (mg/liter)	2.0	1.8
Eh (mV)	284	
TDS (mg/liter)	4182	3864
CO_2 (mg/liter)	261	
Cl^- (mg/liter)	1990	1838
$SO_4^=$ (mg/liter)	2.1	1.9
B (mg/liter)	5	4.6
Ba (mg/liter)	0.025	0.02
Ca (mg/liter)	4.24	3.9
F^- (mg/liter)	3.95	3.6
Fe (mg/liter)	0.025	0.02
K (mg/liter)	104	97
Li (mg/liter)	4.0	3.7
Mg (mg/liter)	0.655	0.61
Na (mg/liter)	1439	1330
$S^=$ (mg/liter)	0.037	0.034
Si (mg/liter)	105	97
Sr (mg/liter)	0.9	0.8

the agreement is quite good. On an individual basis, noticeable differences were observed in: (1) pH which is probably due to CO_2 solubility and sample variation, (2) boron and iron which are probably due to sample variations and analytical uncertainty, and (3) silicon and strontium which are probably due to sample variations and solubility variations.

TABLE 6

EAST MESA WELL 8-1 COMPARISON OF BRINE ANALYSES

	Rockwell	Site Operator
Date of Sampling	4-27-80	4-30-80
Sample Temperature	25°C	20°C
Sample Pressure	1 atm	1 atm
pH/°C	6.01/25	5.87/22.8
Conductivity (μmho/cm)	6400	6470
Cl^- (mg/liter)	1812	1875
B (mg/liter)	6	4.10
Ca (mg/liter)	22.5	21
F^- (mg/liter)	3.6	3.93
Fe (mg/liter)	0.37	0.47
K (mg/liter)	95	95
Li (mg/liter)	3.7	3.94
Na (mg/liter)	1314	1320
Si (mg/liter)	93	105
Sr (mg/liter)	2.0	2.88

In general, considering sample variations, the results are in very good agreement.

In conclusion, the EPRI Mobile Geothermal Chemical Analysis Trailer has demonstrated that it can be moved to different sites without major problems and provide rapid, accurate analyses on geothermal fluids.

For information concerning use of the trailer, contact Mrs. Meredith Angwin, Project Manager, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, California 94304.

SESSION 4

UTILITY PROJECTS AND PLANS

GEOPRESSURED/GEOTHERMAL PROSPECTS (summary)

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The Department of Energy is actively exploring the use of geopressured, geothermal resources as an alternative source of natural gas and energy for power generation. Bands of this resource are located along the Texas-Louisiana gulf coast.

A resource assessment of these "fairways" has been made and reveals that only some of them show potential promise. The major unknowns are the number, size and properties of the reservoirs, and how they are faulted (i.e. how much continuous medium there is between faults).

This GP/GT resource is located at depths in excess of 12000 ft. under extremely high pressure. The water may contain as much as 50 standard cubic feet of dissolved gas per barrel of fluid and have a temperature of 300 - 350^{o} F.

The proposed method to use this resource is to reduce the pressure through a turbine - generating power, strip off the gas as it comes out of solution, and flash the hot water into steam for further power generation. These three sources of energy - pressure, gas and heat - are about equal in energy content. If the water were pure, we could then use it for irrigation. Unfortunately it is saltier than sea water. Disposal becomes a problem.

There are two possible methods of disposal - injection into a shallow reservoir and injection into the same reservoir. The first requires less energy, the second helps maintain reservoir pressure and increases overall total product.

One well, Pleasant Bayou #2, has been drilled and completed by the Department of Energy in cooperation with the Center for Energy Studies, University of Texas at Austin. This well, in Austin Bayou prospect of the Frio fairway, is located in Brazoria County, Texas, and reaches a depth of some 16,500 feet. Pleasant Bayou #1 was completed as a disposal well after drilling difficulties made its use as a production well impossible. Although the comprehensive testing program has only been started, preliminary tests have been discouraging. Fluid temperatures are below 300 F and salinity of the brine is higher than anticipated. The higher salinity (131,000 ppm TDS, instead of the 85,000 ppm expected) has a lower solubility level for the dissolved methane and thus produced about 25 scf per barrel of fluid. Forty to 50 scf per barrel was expected. Only about 85% of the dissolved gas was actually methane, the balance being CO_2 and other inerts.

Based on these preliminary results, an economic analysis of the investment, operating and maintenance costs and the revenue to be gained has been made. The results indicate that the GP/GT resource is not apt to be a viable means of producing power directly. This is for two reasons. The dispersed nature of the resource, i.e. collecting the output from several wells to have sufficient flow, limits the size of generating plants to no more than 20 MW. The disposal problem may require all the temperature and pressure energy of the source. This results in the source being only a net gas producer.

Here the economics are not good. The price of natural gas would have to rise above the equivalent world price of crude oil (about $5.00 per MCF presently) before the return on investment becomes reasonable, even with optimistic assumptions.

Although it is too early to draw firm conclusions, it does appear that this potential resource is smaller than hoped for and that it will not be a major source of energy for the Gulf Coast.

GEOTHERMAL DEVELOPMENTS AT SAN DIEGO GAS & ELECTRIC

Contract No. DE-AC03-76ET28443

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History of SDG&E Geothermal Involvement Up to Present In 1972, the first well flow tests were conducted by NARCO and Magma Power to determine reservoir characteristics such as mass flow, temperature, stability, and mineral content of geothermal brine from the exploration wells. The results of these tests were encouraging. Brine temperatures were relatively hot, and salinity was less than previously experienced. Results were sufficient to justify further testing of the process design to determine an appropriate energy conversion cycle for a power plant. Both the flash cycle and binary cycle were considered. In the binary cycle, geothermal heat is transferred from hot brine to a secondary working fluid by means of heat exchangers. The heated secondary fluid expands to drive a turbine-generator. The flash cycle was rejected because the high measured noncondensible gas content of the brines seriously reduced the cycle efficiency. The reduced salinity was expected to result in reduced scaling characteristics. For these reasons the binary cycle was selected for initial design and field testing.

In 1973, a series of field tests was conducted to support the design of the binary conversion cycle. Unfortunately, a rapid decline in heat exchanger performance resulting from scaling demonstrated a need to reevaluate the cycle design. A flash/binary process was chosen as the basis for facility design modifications and additional field testing. Design modifications were to use as much of the original design as possible in order to minimize cost.

In March of 1974, SDG&E resumed field testing at Niland using reduced size models of the new flash/binary design. The 1974 test program confirmed the decision to modify the design, construction, and operation of the GLEF in a four-stage, flash/binary cycle configuration.

In May of 1975, the design was completed and construction of the GLEF began. Startup operations were initiated and in June 1976 the facility was dedicated.

In the fall of 1976 while debugging and initial operation was being accomplished, a test program was developed to provide additional basic information necessary for the design of a commercial flash/binary geothermal plant. The primary objective of the program was to develop binary heat exchanger heat design data under a variety of conditions.

Several tests from the 1976-77 test program were attempted during this time period. Unexpected operational problems and data primarily related to heavy scaling in the brine system, process oscillations, supply problems with one of the wells (Woosley No. 1), low noncondensible gas content, led to many aborted tests. Testing and operational data, however, were collected and many problems resolved. Analysis and review indicated a major reevaluation of the project was required.

By the fall of 1977, a major reexamination of the cycle and the test program was initiated. The Bechtel/Holt feasibility study was initiated to reconsider the energy conversion process and to recommend further activities, if required. The study was completed in early 1978, concluding that a two-stage, flash cycle process as the most appropriate cycle for the commercial development at the Niland KGRA. Modification of only the brine system at the GLEF was recommended in conjunction with further operation and testing. Consequently, in April 1978, the GLEF was shut down and the brine portion of the plant was converted to a double-flash system. The GLEF began operation in the two-stage flash cycle configuration in July 1978. During the spring of 1979, the GLEF was shut down again, this time to install a brine effluent treatment system. During the summer of 1979, installation was completed and the GLEF was shut down permanently. During this period of two-stage flash operation, a test plan was pursued which included the testing of an effluent brine treatment system (clarifier filter). The generally successful operation of the clarifier/filter was the last major testing program conducted at the GLEF site; however, side stream testing and other activities continued into 1980.

The other activities known as "Commercial Risk Reduction Activities" were devised to quantify major uncertainties impeding construction and development of commercial-scale geothermal power plants.

Within the broad classification of uncertainty are key subelements which have been identified as the major sources of geothermal commercial risk. They include unscheduled power plant outages, unpredictable reservoir performance, and lack of water supply assurances. The Commercial Risk Reduction Activities address the technical, environmental, and institutional uncertainties associated with each of the following development concerns:

- Major permit cancellation of disapproval
- Loss of cooling water supply
- Seismic destruction
- Uncontrolled subsidence
- Prohibitive plant reliability and availability
- Unfavorable rate treatment from Public Utility Commission
- Excessive and uncontrollable corrosion and scaling
- Reservoir behavior

The Commercial Risk Reduction Activities currently consists of the following actions. The level of effort on each activity is a measure of its anticipated economic impact on a power plant project.

- Cooling Water Rights Acquisition and Source Evaluation - The principal purpose of this activity is to obtain long-term supplies of geothermal power plant consumptive water supplies.
- Salton Sea Injection Feasibility - A decision has been made to defer this activity indefinitely.
- Component Development - This activity concentrates on further development of component designs critical to plant operability and efficiency.
- Solid Waste Disposal - The goal of this activity is to expedite the development of a site in Imperial County to accommodate the wastes generated during geothermal operations.
- Airborne Effluents Assessment - A bio-environmental assessment program is being developed to study the potential impacts of cooling tower drift and noncondensible gases.
- Economic/Risk Assessment of Geothermal Development - This activity combines the above Commercial Risk Reduction Activities with other elements of uncertainty to form a quantitative assessment of geothermal development risks to SDG&E.

Work is underway at SDG&E to determine the engineering risk and benefits from commercial-sized geothermal power plants at Imperial Valley reservoirs. The information obtained from these studies will complement earlier work directed to identifying the sensitivity of selective geothermal plant parameters on busbar costs. Capacity factor, a measure of total plant reliability, has been shown to have the greatest impact on busbar costs.

SDG&E has also established a Geothermal Interdivisional Program to bring all company entities involved in various capacities in geothermal together in a team effort. It has identified goals and objectives for geothermal activities in 1980. These activities are supporting the goal of developing at least one commercial sized plant at each major anomoly (Niland, East Mesa, and Heber), in order to obtain necessary cost and operating information to assess the risks of future development.

In a measure to reach these goals SDG&E has stationed an engineer at the Magma East Mesa 10 MW facility as an observor and for technology exchange. This facility has been in the startup phase of operation since early this year. However, problems typical of a new technology such as this (leaking heat exchanger tubes, general equipment debugging, and turbine damage from metal fragments from a broken strainer upstream) have hindered both full and continuous loading of the unit.

Summary and Future Plans The GLEF produced a copious amount of data. These data were not always what was expected, and required a flexible approach for reduction and interpretation. Process design began with a binary cycle which was modified into a flash/binary cycle and eventually converted into a dual-flash cycle with brine effluent treatment. Construction activities were required to quickly adapt available equipment, not specifically designed for geothermal applications, to site conditions. Operational plans changed from a simple long-term pilot plant approach into an optimistic test plant to develop additional detailed process design data from the facility, but was finally limited to obtaining data to reduce critical uncertainties and risk areas. Each of the basic phases (design, construction, and operation) of the project for each process design (binary, four-stage flash/binary, two-stage flash, and the addition of a reactor clarifier media filter system) will be addressed separately in this discussion.

"Geothermal energy offers an interesting alternative to oil-fired electric generation. During the late 1980's, if the cost of oil continues to rise as it has in recent years, there is a potential for geothermal energy to become more economical than oil. Geothermal energy constitutes a significant new resource option that could broaden the company's total generation mix."[1]

1 "Geothermal Could Be An Alternative to Fuel Oil," 1979 Annual Report, SDG&E, p. 10.

Accordingly, SDG&E plans are focused upon collecting, collating, and evaluating all data from the pilot plant activities not only in the Imperial Valley, but throughout the world as well. As discussed earlier in this paper, there are a number of perceived uncertainties with regard to the utilization of geothermal energy to produce electricity. The analysis that will take place in the future will attempt to quantify these uncertainties as well as develop programs to reduce them. By doing so, we hope to be able to reduce a major impediment to the utilization of this resource.

SMUDGEO #1
SACRAMENTO MUNICIPAL UTILITY DISTRICT
FIRST GEOTHERMAL UNIT

By:
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A. INTRODUCTION

This description of the SMUDGEO #1 geothermal power plant of the Sacramento Municipal Utility District (SMUD) and its associated well field development has been prepared to acquaint persons with the project.

B. STEAM WELL FIELD

1. Site Location

The SMUDGEO #1 plant site is located nine miles northwest of Middletown, California, on the eastern edge of Sonoma County in the area known as the Geysers. Access to the plant site is via Highway 175 northwest out of Middletown to the Old Socrates Mine Road. Follow Socrates Mine Road then turn north on the fire road just west of Geysers Unit 13. Santa Rosa is the nearest major community, located about 24 miles south of the site.

2. Aminoil Leasehold

The steam field leasehold covers 396 acres of steep hills with elevations ranging from 2700 to 3800 feet. This leasehold is in the southeastern part of the Known Geothermal Resource Area (KGRA). Estimates of electrical resources from this area range from 2000 to 2600 megawatts.

Both the surface and sub-surface (mineral) rights of the 396 acres are owned by the federal government. These rights are administered by the Bureau of Land Management (BLM), the surface manager, and the U. S. Geological Survey (USGS), the sub-surface manager.

Geothermal resources like the Geysers are found in areas where the hot molten rock from the center of the earth has been thrust upward through recent volcanic actions. Water contained in permeable rock formations near such heat sources becomes heated, rises up to the surface, and appears as hot springs, fumaroles (steam vents), or geysers.

3. Steam Wells

To utilize this underground source of geothermal heat energy, deep wells ranging from 7000 to 9000 feet deep must be drilled. These wells are drilled in the same manner and with the same drill rigs as oil and natural gas wells. Carbon steel well casings are installed to depths of 4000 to 5000 feet and sealed with concrete.

Drilling a well takes from 2 to 3 months and costs from 2 to 2.5 million dollars. Below the casing levels, well bores are allowed to drift along the natural fractures in the rock formations. Bottom hole positions can be several hundred feet from the well pad. Geyser wells average about 150,000 pounds per hour of steam at 115 PSIA with $10^{O}F$ of superheat. This is enough steam to produce 7 to 8 megawatts. There are two wells completed on the leasehold. Well CA 1862-3 is 7975 feet deep and produces 80,000 pounds per hour of steam. Well CA 1862-4, which was completed this month to a depth of 8357 feet, has not yet been flow tested; however, early indications on this well are that it will only flow from 70,000 to 90,000 pounds per hour. An additional well will be completed before the fall rainy season and hopefully be more productive.

It is anticipated that it will take up to eight or nine production wells and one injection well to run the District's nominal 55 MW plant.

4. Steam Gathering System

Each well is equipped with several shutoff and vent valves, a rock catcher, and dust separator. Aminoil proposes to use five well pad sites to develop the 396 acres. Typical rule of thumb for Geysers development is to drill a well every 40 acres.

Multiple wells will be headered together at the well pads and then routed in the most economical way with a minimum environmental impact. Steam will be delivered to the plant site fence line in a 36" diameter insulated carbon steel pipeline.

5. Contract With Aminoil

SMUD has a steam supply contract with Aminoil which requires them to deliver 1,100,000 pounds per hour of steam at 115 PSIA to the plant site fence line. The present 1980 cost of this steam is $1.00 per thousand pounds, or at full load on the plant SMUD would be paying $1100 per hour. This is equivalent to an energy cost of about 7 million dollars per year.

Along with the steam comes hydrogen sulfide gas, which smells like rotten eggs and can have a harmful effect on humans. The Aminoil contract requires that the H_2S in the steam be limited to 200 PPM.

C. PLANT LAYOUT, COST, AND SCHEDULE

1. Site Layout

The power plant site is located in the northwest corner of the Aminoil 7 West Leasehold. This location is dictated by the steep and rugged nature of the terrain. Approximately six acres will be leveled for the plant site proper.

As indicated above, the primary access to the site will be via the existing fire trail from the Socrates Mine Road. This trail will be upgraded, to include paving. A secondary access road leads from the site to the southwest.

Major structures or facilities on the site include the turbine building, the cooling towers, and the H_2S abatement facility. An admin/warehouse/shops building is also shown on the site layout, although a final decision on construction of this building has not yet been made.

The arrangement of the buildings on the site is keyed to the required orientation of the cooling towers, parallel to prevailing winds, and to the available area.

2. Cost Estimate

The total project cost is currently estimated to be approximately $54 million in 1984 dollars. This is an order-of-magnitude estimate, prepared before the placement of major equipment and construction contracts. Of this cost, $29 million is attributable to capital costs, plus $4 million of construction-related costs. Other major costs include approximately $4.6 million in indirect costs, $8.8 million as an allowance for inflation, and and $6.5 million as an allowance for funds used during construction.

Total operating and maintenance costs are predicted to be 46 mills/KwHr when the plant commences operation. Of that, 27 mills/KwHr will be for the steam supply. The plant is expected to generate approximately 385 million KwHr per year.

3. Project Schedule

The SMUDGEO #1 project was initiated by a SMUD Board of Directors resolution to proceed in February 1979. The Architect/Engineer, Stone & Webster Engineering Corporation, was placed under contract in late June 1979.

Initial work on the project consisted largely of preparing the Application for Certification (AFC), the major licensing document for construction approval. The AFC, which has a one-year review cycle, was filed with the California Energy Commission on February 19, 1980. Current licensing activities include a series of workshops and preparation of responses to interrogatories from the CEC, prior to their issuing a Preliminary Report and a Joint Environmental Statement.

Considerable effort is also being devoted to the preparation of specifications for the purchase of equipment. A contract was awarded on May 2, 1980, for the turbine-generator, key equipment for the plant. Other major equipment, such as the condenser, cooling towers, and H_2S abatement system, will be purchased in the summer of 1980.

Construction is scheduled to start in April 1981, after approval of the project by the CEC and the Board. Site grading will take place in the spring and summer, with the civil/structural contractor commencing work in July. A major objective of the first season's construction work is erection and enclosure of the turbine building by December, in order to allow construction of the turbine pedestal and erection of the turbine-generator to proceed under cover. Erection of the turbine-generator, condenser, and cooling tower are scheduled for mid-to-late 1982. Startup activities will commence in early 1983, with commercial operation scheduled for December 1983. The schedule is shown on Fig. 1.

D. POWER CYCLE

1. Typical Cycle

Steam supplied by the well field developer is expanded through a turbine which drives the generator. The spent steam is exhausted into a surface condenser where it is condensed and collected. Circulating water is provided to the condenser for cooling. Circulating water is itself cooled in the cooling tower. The condensate is pumped as makeup to the circulating water system. Excess water is returned to the steam supplier for injection. This cycle is shown on Fig. 2.

2. SMUDGEO #1 Cycle

The cycle for SMUDGEO #1 has been optimized to provide the most power per pound of steam as can be justified economically.

A larger turbine, condenser and cooling tower are provided. 70 MW is produced from the same amount of steam as it takes in the typical cycle for 55 MW.

3. Heat Balance Comparison

For the approximate same amount of steam (pounds per hour), SMUDGEO #1 will produce 70 MW as PG&E and NCPA #2 do to produce 55 MW. The physical sizes of SMUDGEO #1 equipment compare to PG&E 16, a 110 MW unit (Fig. 3).

E. PLANT SYSTEMS AND EQUIPMENT

1. Mechanical

a. Steam Systems

Steam is supplied to SMUDGEO #1 at 100 PSIG and 348^{o}F. It is used for turbine throttle flow, noncondensable gas removal (two stage steam jet ejectors) and process steam to the H_2S abatement system. Since large volumes of noncondensable gases are handled, the plant may be designed with a third stage motor driven vacuum pump.

A turbine bypass is provided to allow complete bypass of the throttle flow on a turbine trip. This will minimize the occurrence of the main steam safety valves.

b. Steam Turbine

The steam turbine will be supplied by Mitsubishi Heavy Industries. It is a four flow machine with 25 in. last stage blades rotating at 3600 rpm. It will normally produce 70 MW.

c. Steam Condenser

The condenser will be as surface type. It will have from 150,000 to 200,000 square feet of 3/4 inch diameter tubes. It will be two zone, single pass operating at 1.35/1.70 inches Hg ABS.

2. Cooling Water Systems

a. Circulating Water

The circulating water system will be comprised of four 25% pumps and a twelve cell cooling tower. It will be divided into two independent loops, crosstied for flexibility and reliability.

b. Service Water

Service water will be provided by two 100% pumps. The water source will be the cooling tower basin and the hot water will be returned to this tower.

c. Injection

Condensate will be used as makeup to the circulating water system. Losses are due to evaporation and drift. Makeup in excess of these losses is returned to the steam supplier for injection.

d. Cooling Tower

The cooling tower is a wet, mechanical induced draft type. It will have 12 cells and will cool 119,000 GPM of circulating water from 89°F to 74°F. Drift will be approximately 1.2 GPM.

3. Station Arrangement

The station has been laid out on the site to keep all major structures in cut area. The main power block has been laid out to minimize piping and to have the most efficient tower siting.

4. Electrical

a. Corrosion

Hydrogen sulfide in the air in the Geysers area has a deleterious effect on copper and certain other metals often used in electrical equipment. For that reason, other metals will be used for electrical contacts and key electrical equipment will be located in a clean environment.

b. Electrical Design of Clean Air Areas

Clean air areas will be provided for the electrical switchgear, relay, communications, logic, and control rooms. Air with a minimum of hydrogen sulfide will be provided for these rooms by filtering the incoming air and maintaining a slight positive pressure.

c. Backup Electrical Design Features

Certain redundancy is designed into the electrical features of the plant. This redundancy is particularly important in regard to operation of the turbine bypass system.

5. Instruments and Controls

a. Philosophy of Operation

SMUDGEO #1 will operate initially as a continuously manned facility, but will have the capability of being converted to a remotely controlled, unattended facility should future operations dictate. Supervisory controls and instrumentation for all major equipment and systems will be located on a main control panel, which is located in the plant control room. The plant control operating area will be designed to permit one operator to supervise the operation of all major equipment and systems.

b. Basic Cycle Control Loops

The following are the basic steam-water cycle loops.

(1) Turbine Electro-Hydraulic Control (EHC)
  (a) speed control during startup
  (b) load frequency control while on-line

(2) Turbine Bypass System
  (a) bypasses geothermal steam around turbine directly to condenser during low/no-load operation

(3) Condensate Flow Control
  (a) condensate recirculation
  (b) condenser hotwell level
  (c) booster pump flow

(4) Circulating Water Flow
  (a) cooling tower-condenser loop

(5) H_2S Abatement System
  (a) primary system treats non-condensable H_2S gas
  (b) secondary system treats H_2S in solution

c. Recording, Annunciating and Printouts

The primary monitoring devices, i.e., hardwired annunciators, indicators, and recorders will be grouped on the main control panel according to the plant system they are associated with (Fig. 4). In addition, there will be a vertical segregation of monitoring and control devices to indicate priorities to the operator.

The printing data logger will supplement the hardwired instrumentation and will provide selected supplementary alarm displays, trend displays and other selected data for historical record and review.

The printing data logger is a programmable, microprocessor based alarm scanner and logger, the failure of which would result in the loss of operator access to many parameter values. Therefore, safe plant operation will not be dependent upon the continued operation of this device. The plant will be operable and capable of being maintained in a safe condition with only the hardwired equipment functional.

F. PROBLEMS/DESIGN CHALLENGES

1. H_2S Abatement

a. Gas Treatment

The steam furnished by Aminoil to operate the plant will contain noncondensable gases (approximately 0.3 percent), to include hydrogen sulfide (H_2S) gas (60±20 ppm). The noncondensable gases will largely be drawn off from the condenser.

Hydrogen sulfide constitutes the most significant potential pollutant from the plant. The District has committed to an emissions limit of 50 grams per gross megawatt hour, provided that air quality studies do not demonstrate that a higher limit is justified. In order to meet this limit it will be necessary to treat both the off-gas and condensate. The off-gas will be treated in a Stretford system (Fig. 5). This system uses a wet chemical process to remove 99+ percent of the incoming H_2S.

b. Condensate Treatment

As indicated, a portion of the H_2S will remain in the condensate. Several possible methods are currently under study for removing all or a portion of the H_2S from the condensate. These are:

(1) Oxidation with hydrogen peroxide
(2) Air oxidation
(3) Ozone oxidation
(4) Condensate stripping
(5) Ammonia fixation
(6) Iron catalyst/sulfate oxidation

The first and last methods are being used (or have been used) by PG&E at the Geysers.

Further engineering and laboratory work are necessary before a condensate treatment system is adopted.

c. Steam Stacking

Steam stacking occurs when a steam supplier releases steam to the atmosphere (other than minor venting). This is generally associated with power plant outages. Since a release of greater than about 30 percent of full steam flow would result in violating emissions limits, Aminoil is responsible for abating the emissions.

The proposed method for controlling steam stacking is to install a bypass which will allow incoming steam to flow around the turbine directly to the condenser. This system has advantages for the District, as well, in that it will allow flexibility in operation.

2. Land Disturbance and Mitigation Plans

Approximately 9.6 acres of terrain will be affected by construction of SMUDGEO #1. The plant site within the fence will disturb 5.3 acres of land. The well pad access roads and the parking area will affect 1.6 acres. The fill areas and sedimentation pond will disturb 2.1 acres, and the site access road and associated fill will disrupt about 0.6 acres. Permanent loss of vegetation cover will occur in the areas mentioned above. Certain animal species in the disturbed areas will be lost (e.g., mice, rabbits, certain terrestrial invertebrates, etc.). However, certain animal species will benefit by the creation of open spaces and "edge" effects (e.g., deer).

The development and implementation of specific measures to offset unavoidable losses associated with a particular land use alternative is termed "mitigation." Mitigation measures associated with SMUDGEO #1 include the employment of revegetating disturbed land surfaces with appropriate native plant species (grasses, shrubs, and certain tree species such as oaks). Irrigation systems, hydromulching with straw and seeds, and plastic netting will all help to insure better revegetation success. Distributing topsoil over the disturbed land will further enhance the revegetation efforts. The creation of browseways by stockpiling removed vegetation to create brush piles, and controlled burning will benefit wildlife and plant life alike. Leaving intact shrub root crowns and roof bushes along the perimeter of disturbed lands will also aid the revegetation efforts. Exclosure fencing of plants used in revegetation might also help their survival chances from adverse effects of mule deer browsing. Revegetation will be monitored periodically during the years following initiation.

No adverse impacts are anticipated on wildlife and fish species near the site - this includes any threatened, rare and endangered species and species of special concern.

3. Compliance and Monitoring Plan

The Energy Commission's regulations require SMUD to prepare a "Compliance and Monitoring Plan." This document describes the manner in which SMUD will comply with applicable laws and regulations in the detailed design and construction of the plant. The monitoring portion of the plan describes the manner in which SMUD will ensure that the plant "as built" is in compliance. Examples are measurements for hydrogen sulfide emissions and the successfulness of the revegetation plan in minimizing erosion. Since SMUDGEO #1 will be sited on federal land, the Energy Commission does not have any direct control once the AFC is approved. Rather, the USGS and the Commission will jointly approve the Plan, which will then be administered by the USGS. A similar plan has been implemented for the NCPA No. 2 project, which is also on federal land.

4. Access Roads and Road Maintenance

As indicated previously, the primary access road for construction and operation will be from the Socrates Mine Road through Birdsong Meadow along the existing fire trail to the site. The only new construction will be a short segment around the original Aminoil well pad to the site gate. The District is committed to paving the access road across the Aminoil leasehold. Some minor realignment may be done, apart from the new segment, as a part of upgrading and paving the fire trail.

A secondary access road leads from the southwest corner of the site to the paved road below. This road, currently in existence, is steep and little more than a trail. It will be upgraded a certain extent, but is intended only for emergency access.

In that the primary access road will be paved, maintenance will be limited to ensuring that the drainage system along the road remains functional and that the road surface remains in good repair.

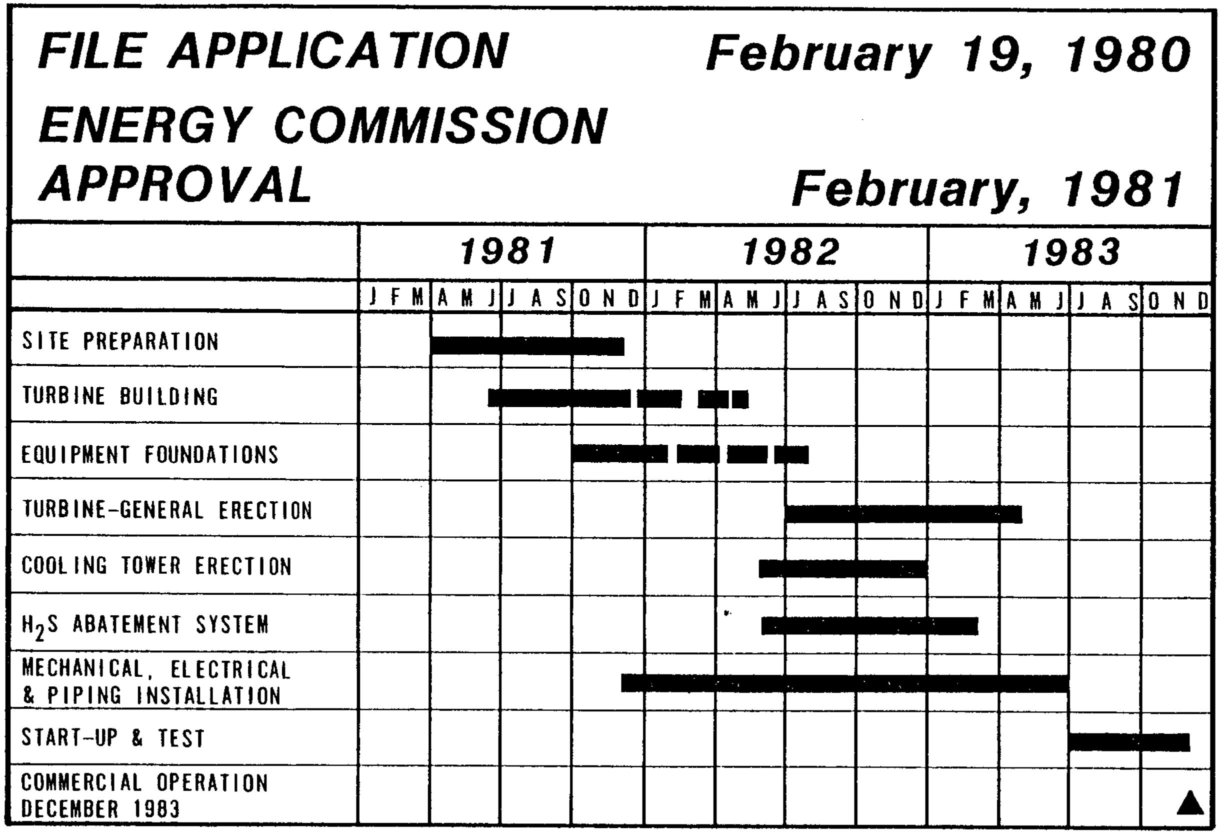
FILE APPLICATION
February 19, 1980
ENERGY COMMISSION APPROVAL
February, 1981
1981
1982
1983
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
SITE PREPARATION
TURBINE BUILDING
EQUIPMENT FOUNDATIONS
TURBINE-GENERAL ERECTION
COOLING TOWER ERECTION
H_2S ABATEMENT SYSTEM
MECHANICAL, ELECTRICAL & PIPING INSTALLATION
START-UP & TEST
COMMERCIAL OPERATION DECEMBER 1983

FIGURE-1

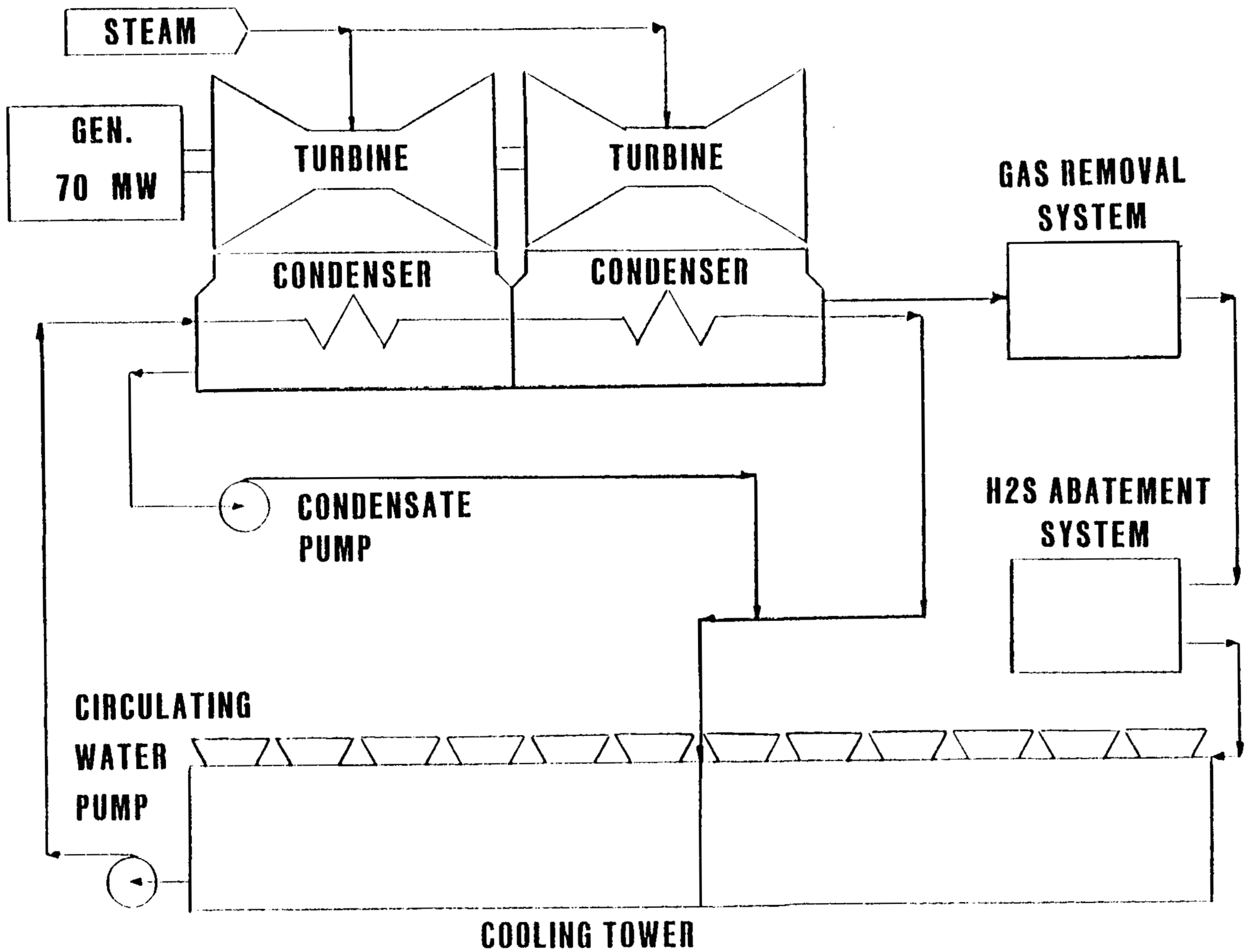
STEAM
GEN.
70 MW
TURBINE
TURBINE
CONDENSER
CONDENSER
GAS REMOVAL
SYSTEM
H2S ABATEMENT
SYSTEM
CONDENSATE
PUMP
CIRCULATING
WATER
PUMP
COOLING TOWER

FIGURE-2

	PG&E UNIT 15	PG&E UNIT 16	NCPA #2	SMUD SMUDGEO #1
STEAM FLOW , LB/HR	1,100,000	1,940,000	983,000	950,000
MEGAWATTS ,GROSS	55	110	55	70
TURBINE				
TYPE	2 FLOW	4 FLOW	2 FLOW	4 FLOW
LAST STAGE BLADE LENGTH,IN	17	23	23	25
CONDENSER				
SURFACE AREA,SQ FT	92,000	184,000	105,000	250,000
OPERATING PRESSURE, IN HGA	4.0	3.0	3.0	1.75
COOLING TOWER				
NUMBER OF CELLS	5	11	6	12
CIRCULATING WATER				
FLOW RATE, GPM	70,000	140,000	67,000	119,000

FIGURE- 3

MAIN CONTROL PANEL

SMUDGEO #1

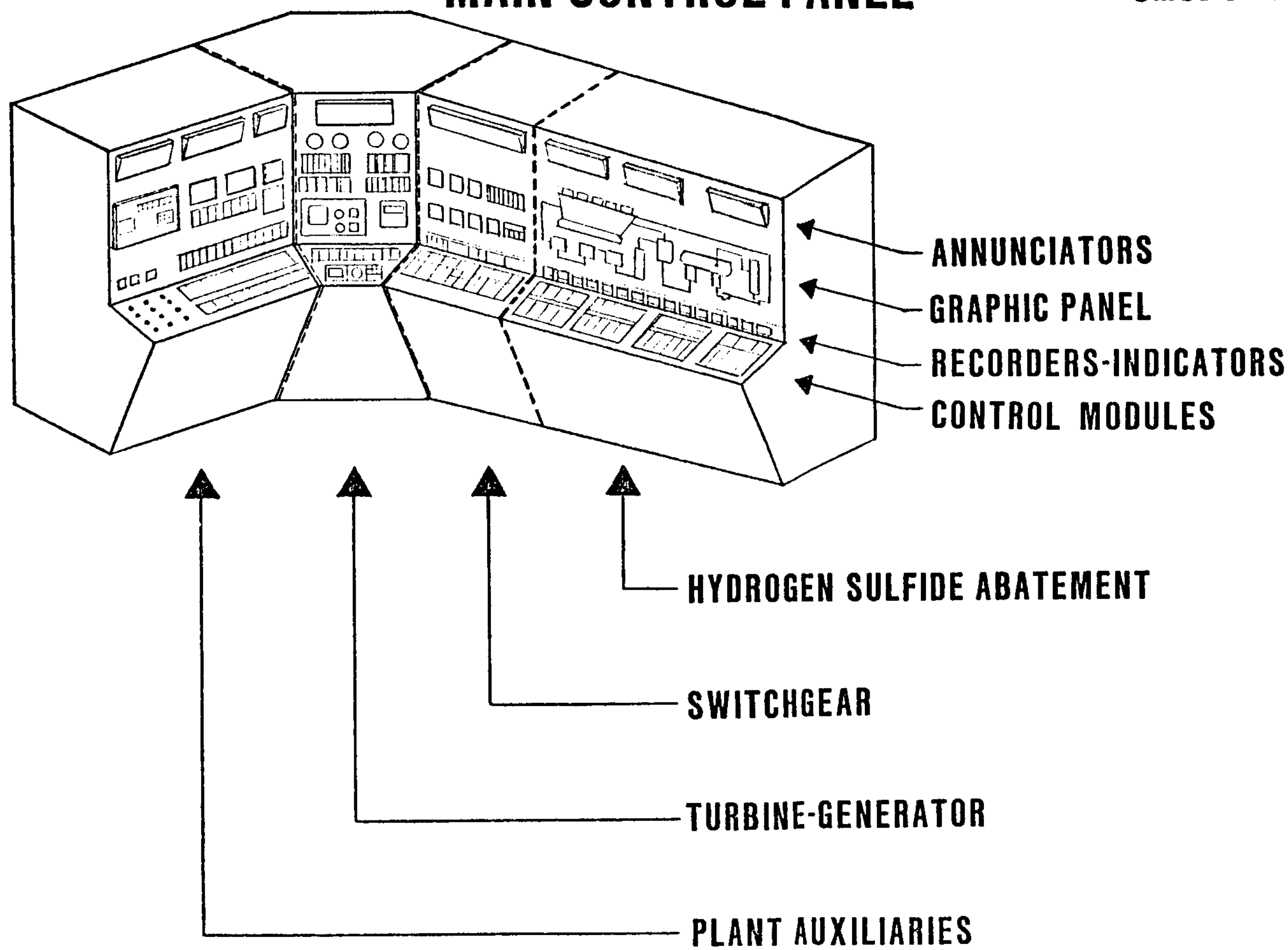

FIGURE- 4

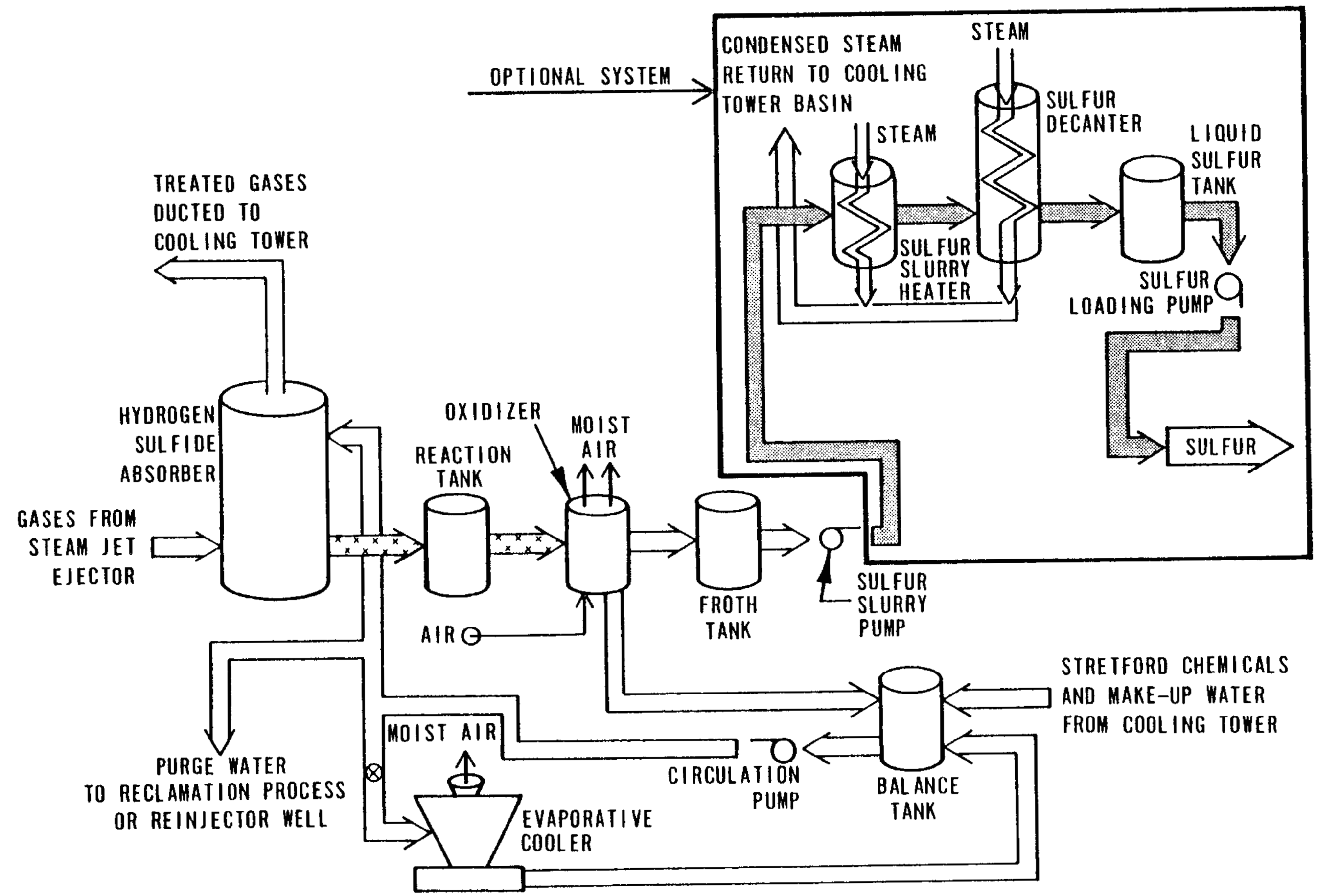
OPTIONAL SYSTEM
CONDENSED STEAM RETURN TO COOLING TOWER BASIN
STEAM
STEAM
SULFUR DECANTER
LIQUID SULFUR TANK
SULFUR SLURRY HEATER
SULFUR LOADING PUMP
SULFUR
TREATED GASES DUCTED TO COOLING TOWER
HYDROGEN SULFIDE ABSORBER
GASES FROM STEAM JET EJECTOR
OXIDIZER
REACTION TANK
MOIST AIR
FROTH TANK
SULFUR SLURRY PUMP
AIR
STRETFORD CHEMICALS AND MAKE-UP WATER FROM COOLING TOWER
BALANCE TANK
CIRCULATION PUMP
MOIST AIR
EVAPORATIVE COOLER
PURGE WATER TO RECLAMATION PROCESS OR REINJECTOR WELL

FIGURE-5

HAWAII'S GEOTHERMAL DEVELOPMENT

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INTRODUCTION

On July 2, 1976, an event took place in the desolate area of Puna, on the island of Hawaii, which showed great promise of reducing Hawaii's dependency on fuel oil. This great event was the flashing of Hawaii's first geothermal well which was named HGP-A.

The discovery of geothermal energy was a blessing to Hawaii since the electric utilities are dependent upon fuel oil for its own electric generating units. Over 50% of their revenues pay for imported fuel oil. Last year (1979) about $167.1 million left the state to pay for this precious oil.

The HGP-A well was drilled to a depth of 6,450 feet and the temperature at the bottom of the hole was measured at 676°F, making it one of the hottest wells in the world.

HGP-A WELLHEAD GENERATOR PROJECT

In order to determine the feasibility of generating electricity with a small geothermal power plant in a rift zone and to obtain additional information on the characteristics of the resource, a consortium called the HGP-A Development Group was formed. The members of this group consist of the following:

1. State of Hawaii, Department of Planning and Economic Development.

2. County of Hawaii

3. University of Hawaii, Hawaii Geothermal Project.

Hawaiian Electric Company, Inc. (HECO) and its subsidiary, the Hawaii Electric Light Company, Inc. (HELCO), serve as advisors to this group. HELCO will be contracted to operate and maintain the power plant facilities including the well. Also, HELCO will purchase the electricity generated from the station.

The Development Group was successful in obtaining over 90% of the funding for this project from the U. S. Department of Energy. The balance of the funding will be provided from the State and County of Hawaii and HELCO. The Development Group contracted the Research Corporation of the University of Hawaii to manage the project.

PROJECT SCOPE

The scope of the project is to design and construct a 3 mw geothermal power plant with full environmental controls. The plant is to be operated and maintained for approximately 14 months. The electrical energy generated will be connected to the HELCO grid system for purchase by HELCO.

HGP-A WELLHEAD GENERATOR
PROOF-OF-FEASIBILITY PROJECT

RESEARCH CORPORATION OF THE UNIVERSITY OF HAWAII
ROGERS ENGINEERING CO., INC. ENGINEERS • ARCHITECTS SAN FRANCISCO

SPONSORS:
U.S. DEPARTMENT OF ENERGY
STATE OF HAWAII
COUNTY OF HAWAII
UNIVERSITY OF HAWAII
HAWAII ELECTRIC LIGHT CO.

In addition, a Visitor Information Center will be constructed at the plant site to educate the public on geothermal energy. The public will also be able to view the geothermal power plant from a vantage point at the Visitors Center.

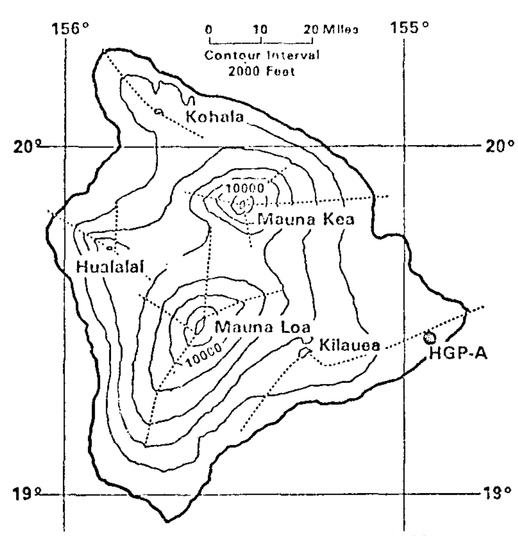
DESIGN CONSIDERATIONS

The major design consideration of this project are the risk of volcanic eruption, the environmental impact, and the remote operation of the plant.

1. Risk of Volcanic Eruption

HGP-A is located on the eastern end of the east rift zone on the island of Hawaii. Because there is a risk of volcanic eruption occurring near or at the site, the plant is designed so that specific pieces of equipment could be easily removed and transported to a safe area to avoid lava flows. The wellhead assembly is also designed so that it can be protected from lava flows by covering it with an insulating layer of cinders when the need arises.

Locations of HGP-A, Volcanoes and Rift Zones on the Island of Hawaii



2. Environmental

Every effort has been made to provide the necessary environmental controls to limit air, water and noise pollution. Of particular concern is the rotten egg odor of hydrogen sulfide gas which is typically present in geothermal fluids.

In order to insure the effectiveness of the environmental controls, a comprehensive monitoring program will be carried out by an independent company.

Furthermore, the architectural treatment and landscaping characteristics will be compatible with the natural surroundings of the site. The area along Pohoiki Road will be landscaped with trees and shrubs to provide a buffer-screen of the plant facilities from the road and would maintain the natural character of the environment in that area. The buildings will be painted so that they will also blend with the area.

3. Plant Operation

The power plant is designed to operate remotely from HELCO's control room in Hilo. HELCO will provide personnel at the plant, one shift per day, for routine operation and maintenance of the plant. The electrical output of the generator--2.8 megawatts--will be fed into the HELCO electric system grid and provide electricity for the residents throughout the Puna District. Since HELCO can only accept 2 mw during low load periods, load banks are being provided to consume the excess generation that the system cannot accept. HELCO will pay for the power fed into its system and the revenue will be more than adequate to offset the operating and maintenance costs.

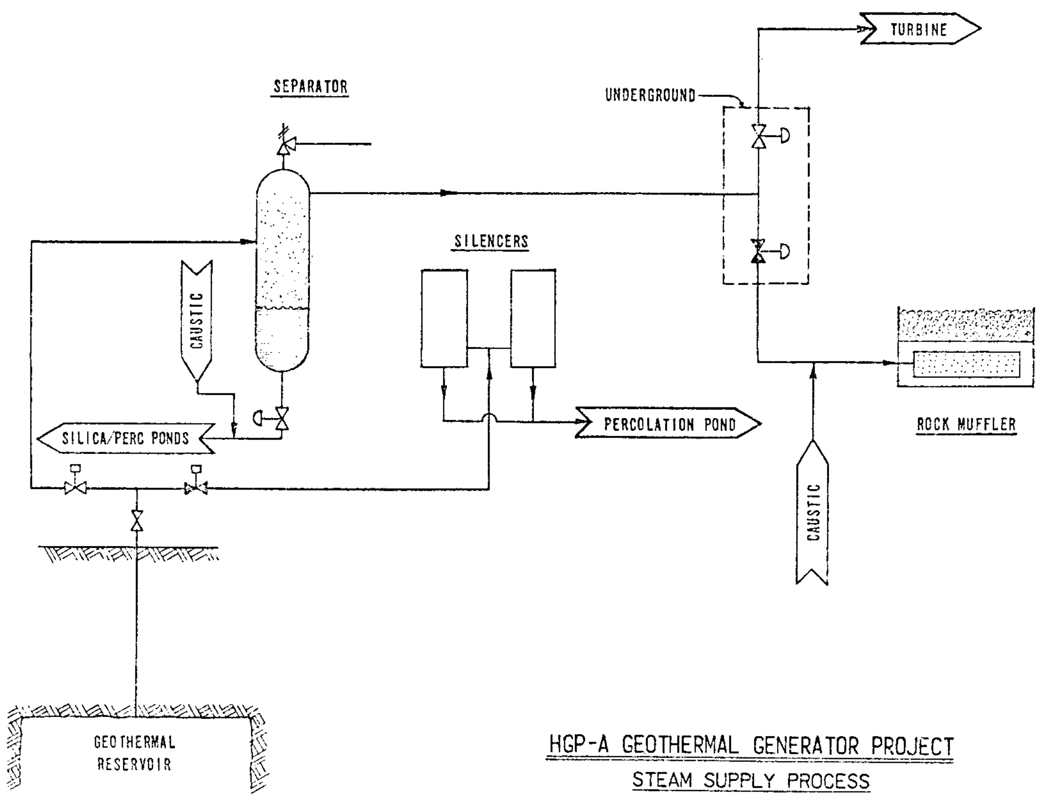
DESCRIPTION OF THE SYSTEM

Steam flows from the well into a steam flash separator where the steam and water phases are separated. The steam then enters the turbine-generator at 52,800 lbs/hr at 371°F and 160 psia to produce 3,000 kilowatts of electrical power. The plant will use about 200 kilowatts for its auxiliary equipment and the remaining 2,800 kilowatts will be transmitted into HELCO's electrical system.

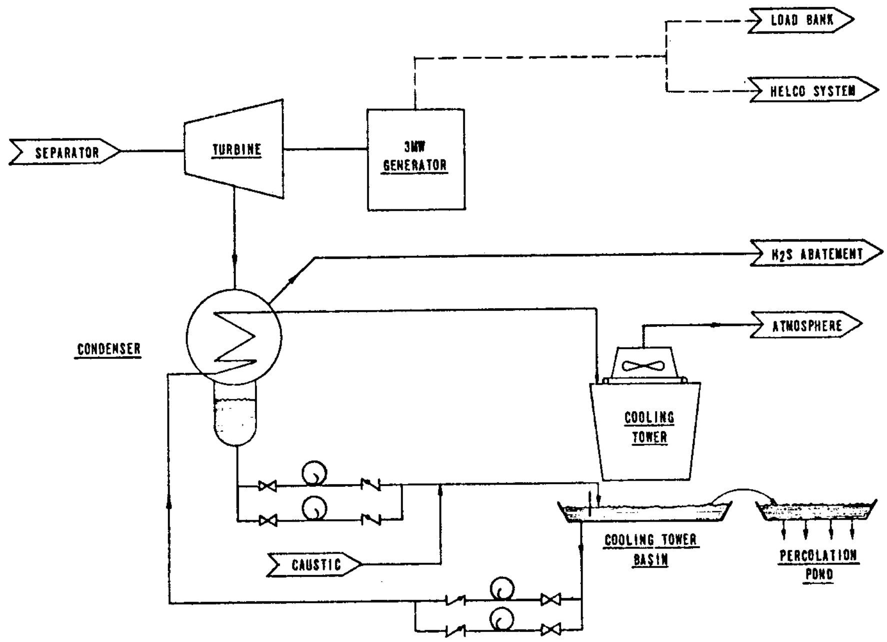
The steam that flows through the turbine is condensed to obtain maximum useful energy from the steam. The condensate formed is used as make-up water for the cooling water system. This make-up water is important since about 100 gals/min of cooling water is lost by the evaporative cooling process in the cooling tower. The excess condensate will be disposed by percolating it back into the ground. Before this can be done, however, silica is precipicated out of the water by allowing it to cool in a retention pond which is designed for a residence time of about an hour.

The hydrogen sulfide and other non-condensable gases are extracted from the main condenser by a two-stage ejector system and burned in an incinerator. The result of this burning process forms sulfur dioxide gas--another pollutant. The flue gas is therefore piped to an absorber column where the sulfur dioxide is removed by absorption in a diluted caustic soda solution before the flue gases are vented to the atmosphere.

The net generation is 2.8 mw since 0.2 mw is required for the plant auxiliaries. Regulation for lower loads will be accomplished by using the load bank which has a capacity of 1.6 mw and the steam dump valve. Therefore, the turbine-generator could be operated continuously in the event of a transmission line failure. In this event, the generator would be cut back to 1.8 mw (0.2 mw for the auxiliaries and 1.6 mw to the load

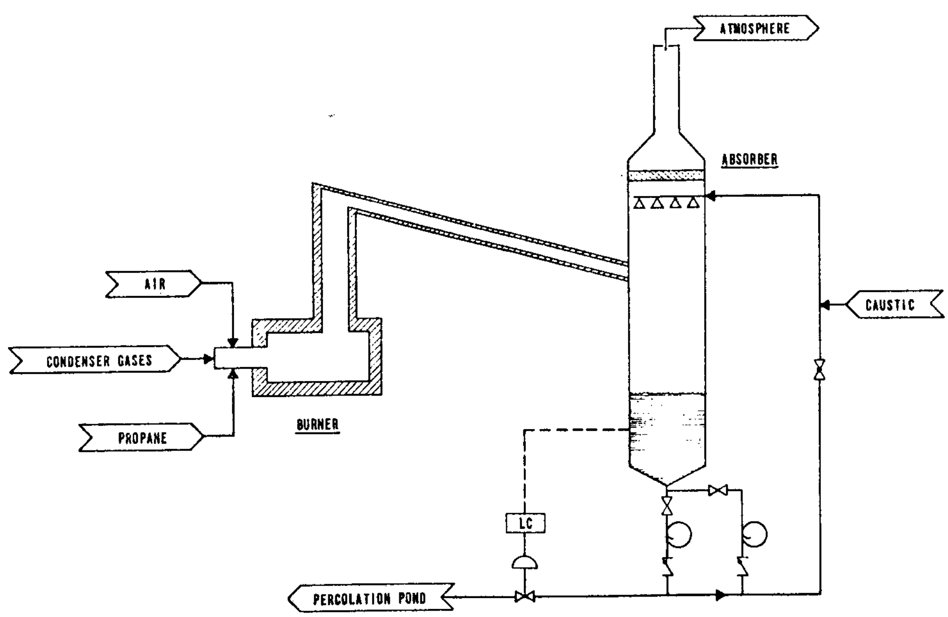


HGP-A GEOTHERMAL GENERATOR PROJECT
STEAM SUPPLY PROCESS



HGP-A GEOTHERMAL GENERATOR PROJECT

OUTPUT AND HEAT REJECTION



HGP-A GEOTHERMAL GENERATOR PROJECT

H_2S ABATEMENT PROCESS

bank) and 1.2 mw equivalent steam flow would be dumped.

Upon turbine trip, 100% of the steam flow will be dumped through the emergency dump valve and the steam treated for H_2S and silenced.

Since this plant is being supplied by only one well, steam flow from the well is not regulated. Flow from the well is maintained at a continuous rate. It is not desirable to shut off the well since it takes about a month to bring the well up to normal operating condition after it is shut off. Therefore, unless major work is required the well will be allowed to flow.

REPAIR OF HGP-A WELL

This project had its first major problem this past summer. A rapid increase of static wellhead pressure with a corresponding increase in the temperature profile of the well indicated that the integrity of the cement bond on the well casing had deteriorated. This suspicion proved to be true after cement bond logs were taken.

The original 9-5/8" casing was installed from a depth of approximately 2,200 feet to the surface. The casing was repaired by first perforating holes in the casing and squeezing cement through these holes to attempt filling the voids on the outside of the casing. Since only 80% bond was achieved by this method, a new string of 7-inch casing was installed and cemented-in solid from the 3,000 foot depth to the surface. This process required cutting and removing 800 feet of the existing 7-inch slotted liner from 2,200 foot to the 3,000 foot depth. This improved the integrity of the cement bond and prevented the intrusion of an undesireable zone of lower temperature fluids from entering the well.

WELL FLOW TEST

A well test was conducted in January 1980 to confirm the well flow characteristics. This test was required before committing the power plant condensing and gas removal equipment. The repairing of the well added to the necessity of conducting the well flow test.

Since a commitment was made to the residents of the adjoining subdivision that noise and the smell of H_2S would be abated during operation of the well, these abatement processes were also tested during this period.

The noise from the discharged steam was abated by the use of a rock muffler. The rock muffler is a concrete box with a plenum chamber at the bottom in which the steam enters through a perforated pipe. The steam velocity is reduced and dispersed through a five-foot bed of 1"-1½" crushed rock. The rock muffler proved so effective that the noise level at the road fronting the well site, about 100 feet away, was only 44 DBA.

The H_2S odor was controlled by injecting caustic and hydrogen peroxide into static in-line mixers made of steel baffles installed in the discharge pipe. The caustic reacts with the H_2S to form sodium sulfide and water, thus removing the smell of the rotten egg odor of this gas. The hydrogen peroxide oxidizes the sodium sulfide to a sulfate to prevent it from reverting back to H_2S.

The total amount of H_2S from the well was found to be about 806 ppm. Of this amount, 790 ppm was present in the steam line downstream of the steam separator. The remaining 16 ppm was found in the liquid line from the separator.

About 97% overall abatement was achieved with this process. An injection rate of 3.2 moles of caustic solution per mole of H_2S was found to be effective, reducing the H_2S level in the discharged steam from the rock muffler to less than 10 ppm. The liquid drained from the rock muffler was the black sulfides with a PH in excess of 11.

The rock muffler also contributed to the effectiveness of the H_2S abatement process since the rock surfaces provided an extremely large wetted surface contact area for the H_2S and caustic. Also, it served as an effective coalescence which prevented the caustic mist from discharging in the steam plume.

Since the caustic treatment proved to be effective by itself, the additional treatment of hydrogen peroxide was not necessary and will not be used in the emergency abatement process. The liquid from the rock muffler drains into a percolation pond giving little opportunity for it to be acidified and reverting back to H_2S.

The well test confirmed the steam flow rate and condition to adequately produce 3 mw of electricity at the design conditions. Preliminary results of the well test for non-condensable gases and dissolved solids are as follows:

Total Non-condensable Gas in Steam	-	1940 ppm
H_2S in Steam	-	790 ppm
H_2S in Brine	-	16 ppm
Total Dissolved Solids in Brine	-	5000-6000 ppm
Silica in Brine	-	840 ppm

SCHEDULE

Construction of the plant facility is in progress. The mechanical, electrical, and instrumentation work will be out for bids in mid-June 1980. The plant is scheduled to start-up on March 31, 1981.

FUTURE OF GEOTHERMAL DEVELOPMENT IN HAWAII

Several geothermal development groups have shown interest in developing geothermal energy in Hawaii. HELCO is preparing a Request for Proposal (RFP) in order to solicit their proposals and to fairly evaluate their financial standings and their technical knowledge and experience in the geothermal field.

Presently, HELCO is only interested in purchasing the electricity that is generated from geothermal power plants. However, HELCO wants the option to purchase the plant at a later date after the resource is proven.

Two major problems that face the geothermal developer are the volcanic hazards in the Puna District and the market for geothermal energy.

The east rift zone in Puna, Hawaii is subject to the highest risks from volcanic hazards in the State. Several eruptions have occurred along the east rift zone in recent years, the most recent being the Pahuahi crater which erupted in November 1979. Wells, piping and power plants installed on the lower slope of the east rift zone must be carefully located and protected from the volcanic hazards. These hazards include volcanic eruptions, lava flows, earthquakes, subsidence, and surface ruptures.

The electrical demand on the island of Hawaii is small. The system peak for 1980 is projected to be 88.4 mw. The average load growth is 3.5% per year. Therefore, any additional capacity would probably be in small increments. Large capacity units would necessitate HELCO to cycle or even shut down their steam units since their loads could drop to about 30 mw during low load periods.

The price for the energy should be economically attractive to HELCO as compared to power purchased from the sugar plantations and to the price of fuel oil and its availability.

Development of geothermal energy in the islands could be accelerated if a submarine cable could be laid from the island of Hawaii to Oahu where the largest load center is located. This cable, however, would have to be capable of being installed on the ocean floor in the 6,000 to 7,000 foot deep channel between the islands of Hawaii and Maui.

CONCLUSION

HECO and its subsidiaries are dependent upon fuel oil for its own electric generating units. Geothermal energy offers the best alternative to fuel oil since it is among the most economical and least polluting of all fuels. Being a natural resource, it could improve the State's balance of trade by reducing the outflow of millions of dollars annually for imported oil.

Developers of geothermal energy must prove the reliability of the resource, provide protection from the volcanic hazards, and be economically competitive with the conventional oil-fired units before geothermal energy could make a large contribution in the generation of electricity in Hawaii.

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H_2S ABATEMENT AT THE GEYSERS

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This paper discusses the efforts by the inter-departmental task forces which have been formed by PGandE to improve and expedite the development, design, installation, and modifications to hydrogen sulfide abatement and abatement-related systems for The Geysers power plants.

BACKGROUND - One of the most critical issues at The Geysers-Calistoga KGRA is the control of hydrogen sulfide emissions, which is an obstacle to the growth of geothermal energy utilization. Hydrogen sulfide is a component of the geothermal fluid and is released to the atmosphere at several locations within a power plant complex, primarily in the plant cooling towers. In the atmosphere it is transported to surrounding regions and can result in an odor nuisance if the concentration is sufficiently high. The California ambient air quality standard for hydrogen sulfide is 0.03 ppm for a one-hour average and was imposed to minimize the odor.

The Geysers Project Office was established by PGandE on December 1, 1978 to improve planning, design, and construction of Geysers power plant units. The Geysers Project Manager is responsible for the on-time, on-cost, and on-specification completion of new Geysers power plant units, including retrofitting the H_2S abatement systems on units now in commercial operation. A Geysers Project Abatement Engineer was added to the Geysers Project staff to provide project direction and a more unified effort by the Company in the area of H_2S abatement by coordinating the work of the many functional PGandE departments involved with H_2S abatement. This responsibility includes assuring that the agreed-upon scopes of work, alternative approaches, and regulatory commitments are met; schedules are established, updated, and maintained; costs are estimated and controlled; and that problems , project status, and program modifications, changes, or variations are promptly reported to management.

The establishment of the position of Geysers Project Abatement Engineer, while establishing a single focal point for H_2S abatement and indicating the importance that PGandE places on resolving the H_2S abatement problem at The Geysers power plants, did not provide the necessary resources to solve certain abatement problems. As a result, in the past year, three different inter-department task forces were established to deal more effectively and more expeditiously with specific H_2S abatement work. These task forces are: The Secondary Abatement Task Force, The On-Site H_2S Abatement Task Force, and The Task Force for Decision Analysis on Units 1-12.

ON-SITE H_2S ABATEMENT TASK FORCE - The Geysers Units 1-12 are direct-contact condenser units, not originally designed with H_2S abatement as a consideration. Abatement systems for these units are "backfit" or "retrofit" technology systems.

Six of these, Units 3, 4, 5, 6, 11, and 12, have been retrofitted with the iron/caustic/peroxide system whereby the H_2S is oxidized in the condensate to elemental sulfur; the emissions of H_2S to the atmosphere are limited to that fraction that remains as dissolved hydrogen sulfide, sulfide, or as molecular H_2S. These iron/caustic/peroxide abatement systems were developed by PGandE and installed within extremely restrictive regulatory constraints in order to achieve abatement as rapidly as possible. Normal design and construction practices were modified to meet the regulatory deadlines.
During 1979, the first full year of operating the iron/caustic/peroxide systems, PGandE found that the performance, maintenance, and reliability of these systems was unsatisfactory. Actions were initiated and continued throughout the year to improve and upgrade these systems; but late in 1979 it was recognized that a more coordinated effort was necessary to assure that the work would be completed expeditiously.
On January 4, 1980, an On-Site H_2S Abatement Task Force was established to concentrate the effort on these abatement systems. This Task Force is specifically charged with assuring that the abatement systems for Units 3, 4, 5, 6, 11, and 12 are upgraded and improved as appropriate. As a secondary purpose, the Task Force is upgrading the sulfur and iron sludge removal systems for the same units and the interim iron abatement

systems at Units 2, 7, 8, 9, and 10. Initially, the Task Force identified the requirements needed to maintain reliable abatement systems and to resolve the outstanding problem; next, scopes of work were agreed upon and schedules were established. Physical work is well underway. Typical work items include providing redundant pumps, adding and upgrading instrumentation, and providing complete system schematics and drawings.

The Task Force Coordinator is a full-time position, reporting to the Geysers Project Office. On the Task Force are representatives of the following PGandE departments: Department of Engineering Research, Engineering, General Construction, Steam Generation, and Division Operations (Geysers Power Plant). The Task Force collectively identifies and agrees upon work tasks. Responsibility for specific tasks is assigned to the appropriate departmental Task Force representative who assures that the task is completed in accordance with the established schedule.

While the work of this Task Force will not be complete until the end of this year, positive results have already been obtained in terms of improved reliability of these systems and more positive control of H_2S emissions.

THE SECONDARY ABATEMENT TASK FORCE - In 1975 PGandE concluded from the operation and maintenance problems associated with the iron catalyst abatement system, that it should not be continued on future units. This was not the technically and economically acceptable solution to the problem of H_2S abatement that PGandE wanted.

Starting with Unit 13 new Geysers units are equipped with surface condensers and Stretford systems for hydrogen sulfide abatement. With this system the H_2S is separated from the condensate in the surface condensers. Original estimates of distribution of H_2S to the off gas in surface condensers ranged from 80 percent to over 90 percent. The vent gas from the condenser is treated by the Stretford process. The Stretford process has been proven in use for some years in the oil refining industries.

In June 1979, Geysers Unit 15, the first unit using a surface condenser and Stretford system for H_2S emissions control, went into commercial operation. Operation of this unit showed that absorption of H_2S into the steam condensate was greater than expected.

Although the Stretford process itself is about 99-plus percent efficient, removing essentially all of the H_2S that reaches it as a gas, the overall H_2S abatement efficiency is dependent upon the distribution of H_2S that occurs in the surface condenser.

H_2S abatement regulations issued by the Northern Sonoma County Air Pollution Control District require Unit 15 and future units in Sonoma County to achieve an H_2S release of no more than 100 g/GMHR after January 1, 1980. (For Unit 15 this is approximately 13.5 lbs/hr.) The release could be further reduced as a result of these regulations to 50 g/GMHR on January 1, 1985. The Lake County Air Pollution Control District has issued similar regulations.

At startup, Unit 15 did not meet these limits. Furthermore, surface condenser-Stretford systems by themselves may not be able to achieve these levels of abatement at other units.

As a result, it was necessary to develop a supplementary or "secondary abatement" for Unit 15 and the subsequent surface condenser/Stretford system for Units 13, 14, and future units.

Because of the complexity of the problem and the number of departments involved, the Geysers Project Office established a Task Force, in June 1979, to resolve the secondary abatement problem. Project direction is provided by the Geysers Project Abatement Engineer for the development of plans, objectives, and schedules to expedite secondary abatement development and implementation. This is accomplished through better communication and a more unified approach between departments. The Task Force members represent the following PGandE departments: Department of Engineering Research, Mechanical and Nuclear Engineering, Civil Engineering, Siting, Steam Generation, Geysers Project Office, and a chemical engineering consultant. The Task Force meets every two or three weeks to discuss the secondary abatement development, engineering, construction, and operational problems. The necessary exchange of information is encouraged in this open forum with easy communication. Scheduling and control of all aspects of the secondary abatement work is expedited.

To date, three processes have been identified and are being investigated for use as secondary abatement systems at surface condenser-Stretford units. These are: 1) Hydrogen peroxide and hydroxyacetic acid/iron catalyst injection into the condensate; 2) High temperature and pressure air oxidation treatment of condensate, and 3) Acid spray injection into the condenser.

The first two processes treat the condensate so that the H_2S is oxidized and remains in the condensate as soluble sulfates and thiosulphates. The third process, acid injection, changes the condensate in the condenser from an alkaline to an acidic pH; consequently, the H_2S is preferentially distributed in the surface condenser to the vent gas and delivered to the Stretford process where the H_2S can be distributed to the Stretford system.

The regulatory timetable for controlling H_2S emissions at the new units, Units 15, 13, and 14, required us to proceed with the implementation of some form of secondary abatement, even though none of these processes had been thoroughly tested. In view of these requirements, PGandE decided to install the hydrogen peroxide and HAA/iron catalyst process based on the fact that it was furthest along in development.

At the present time we are maintaining installation schedules for the process; we have met operational commitments for these systems at Units 15 and 13, and will do so at Unit 14. The initial months and weeks of operation of the hydrogen peroxide and HAA/iron catalyst process have been satisfactory, and we are now awaiting longer-term operation and test results.

In summary, the Secondary Abatement Task Force has served as a focal point where all the secondary abatement work, research, development, design, and construction can be coordinated.

TASK FORCE ON A DECISION ANALYSIS FOR GEYSERS UNITS 1-12 - As previously stated, Geysers Units 1-12 are direct-contact condenser units which were not initially designed with H_2S abatement as a consideration. Further, we are not satisfied with the iron/caustic/peroxide system as a "final solution" to abating these units. Even though this system is installed at six of the twelve operating units and we are attempting to improve its operations through the previously-mentioned On-Site Task Force, we also believe that in the long term we need a better system; one that is more reliable, less detrimental to our power plants, more economic, and safer.

We are actively considering and investigating a large number of alternative abatement processes and process combinations for long-range application at Units 1-12. Among the processes being considered, investigated, and/or developed are: EIC, Coury, Caustic Scrubbing, Acid Scrubbing, Iron/Caustic/Peroxide Enhanced with Nalco Dispersant, Dow Iron Chelate Catalyst, Surface Condenser Backfit, Acid Injection into Condensate, Vacuum Stripping, Catalytic Air Oxidation, High Temperature and Pressure Air Oxidation, Stretford, Takahax, Selectox, Incineration, and Fluidized Bed.

Our most immediate concern in this area of our abatement work is the decision with respect to implementing an abatement system for Geysers Unit 7. We are now operating under a variance from the NSCAPCD regulations. This variance allows remaining direct-contact condenser units, Units 1, 2, 7, 8, 9, and 10, to operate with only natural abatement. (Except for certain periods based on meteorological conditions when "interim" abatement is used on Units 2, 8, 9, and 10.) Interim abatement is the use of the iron catalyst. This variance is tied directly into the development of the EIC process which we have been investigating for long-range applications of that process at Geysers Unit 7. Recently, we requested and received a delay of that decision until July 1980.

Because of the ramifications and implications that this Unit 7 decision has on the remaining unabated units, and also on any decision to replace abatement systems at the six units abated with the iron/caustic/peroxide, the Company initiated a formal, rigorous decision analysis to define the risks and establish a level of confidence in the resulting decision. To expedite the decision analysis process, another Task Force was formed. The specific objective of this Task Force was to analyze all the potential abatement methods and to make a recommendation for the decision to be made for Unit 7. In addition, recommendations were to be made regarding the other five unabated direct-contact condenser units and eventually for the possible replacement of the iron/caustic/peroxide at Units 3, 4, 5, 6, 11, and 12.

Departments represented on this Task Force are: Department of Engineering Research, Engineering, Steam Generation, Siting, and the Geysers Project. An outside consultant has been hired to provide decision analysis techniques. This Task Force held its first meeting on January 30, 1980, and met regularly through the end of May. This Task Force has essentially concluded its work and the recommendations are being considered at this time by PGandE management for a final decision.

CONCLUSION - The formation of special task forces to accomplish specific objectives has drawn together the various functional departments to expedite and aid the effort to bring overall solutions to H_2S abatement problems at The Geysers.

UTILITY PERSPECTIVES ON

NORTHWEST ENERGY PROJECTS

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Projections of Northwest electrical power supplies during the 1980's indicate shortfalls. The planning base for this Northwest supply encompasses all the new generating resources under construction, as well as some planned, but not started, thermal generation. Of significance to the Northwest is their large amount of hydroelectric generation which, in essence, forms the base of the whole Northwest power grid. This generation comes from federal, investor and public utility owned dams on the Columbia and Snake Rivers and their tributaries. The planning base for the 1980's assumes low water availability from rainfall. This forecast is based on the lowest rainfall period encountered over the period of time that records have been kept. For those from the Northwest, the term "amount of snow pack" is indicative of available water and hence available energy for the ensuing year. This equates to "hitching your generator to a cloud" but it has worked well over the last 40 years and is being constantly improved through additional reservoirs and river flow management which maximizes power output. Periods of excess hydroelectric power occur during the spring runoff period when reservoir capacities have been exceeded and electrical loads have been satisfied. This situation reverses as the river flow and reservoir levels diminish in the summer. Fall of the year precipitation supports winter loads unless aggravated by several cold winters in which stream flow diminishes. Thermal plants have entered the generation picture in the last 10 years along with the advent of two coal plants, one in Oregon and one in Washington. Nuclear plants have entered with one plant in Oregon operating and five in various stages of construction in Washington. The reason for the entry of large thermal plants is that major hydroelectric sites have been used. Remaining sites are small or are locked in wilderness or closed areas. Continued effort in thermal generation must go on.

Forecasting in the Northwest is a joint effort of the utilities. Load growth estimates in the late 1980's are in the range of one new thermal project per year. Those projects have to begin very soon. These new thermal resources are generally thought of as coal and nuclear. The existence of geothermal resources in the Northwest provides another capability which may be utilized in the planning. In order to plan for its use, it will have to be a commercially available system. The amount of electrical power provided by this resource during the 1980's would not be large. It is, however, available energy and needs to be considered and provided if reasonably possible.

It would be assumed that the geothermal electrical energy could be accommodated whenever it was provided and in whatever quantities were available. Its mode of use would be to support the Northwest load which will allow schedule adjustments on major resources or reservoir adjustments which improve hydro generation capability. Geothermal capability in the Northwest is awaiting certain developments. In the resource assessment development area it has been assumed that the major resource found will be moderate temperature hydrothermal in the range of 300°F. So far this is an assumption because there is lack of deep well drilling to really explore what exists. So far drilling in Washington and most of Oregon and the major part of Idaho has been limited to exploratory heat rate determination. New resources must be of a temperature compatible with existing technology to provide the incentive for resource companies to do deep well drilling. This activity needs significant effort in the Northwest.

Institutional and regulatory processes differ between the states. Certain procedures and regulations pertaining to usage and development of geothermal resources do not yet exist. This is a major leg of the development process. It has to be intact before the resource can be used.

Equipment and process development capability for generating electrical power from moderate temperature resources is currently being developed. Several development programs are underway which utilize the binary system. Where is the location of the economic break point with regard to generating costs utilizing this system. It has yet to be determined.

Describing these activities in more everyday terms; there needs to be an identified, useable geothermal reservoir compatible with developed hardware, all of which can be pulled together under a useable licensing and siting process.

Each of the activities mentioned above is a major province of a different agency. The users, which may be a resource company and a utility company or a utility alone, have to have support in bringing various portions of the programs together. The states and federal government should provide some incentive toward resource assessment and later development of their lands. An initial assessment may be enough to get the developer interested. The establishment of the institutional and regulatory process is also the province of the state and federal government. Support will be required from the user. Equipment and process development stems from agencies such as the federal DOE, EPRI and the equipment companies. None of these can succeed without the success of the others but hopefully the successes will be very nearly on the same schedule.

Geothermal economics may be unfairly compared to other major thermal projects in today's world. New thermal projects, at best, can be on line in 1988, if initiated now. To which economics do you compare, 1980 dollars or do you compare 1988 dollars? Obviously, with first generation hardware and the unknowns existing, today's energy from geothermal is expensive but don't forget the learning curve and the increase efficiency derived through operating experience. Also don't forget that energy availability may be more important than economics if one considers the cost of oil generation and the impact on regional economics; it might be worthwhile to pay more for your local energy sources.

The only existing Northwest geothermal electric activity is the federal DOE's project at the Raft River Reservoir in Southern Idaho. It is the 5MWe binary system with a resource temperature slightly below 300^{o}F. Utilizing isobutane, this system will provide an idea of generation economics for that temperature utilizing specific process equipment. Northwest utilities are participating in the project through an agreement with the DOE and the DOE engineering contractor, EG&G, at the Idaho site. The principal effort is to support EG&G during the startup and testing of the facility and then have prime responsibility for taking the project through its production testing phase to determine capability and real production economics. There are a number of project goals to be achieved but the major purpose of this endeavor is to determine whether this process equipment is economically compatible with other energy costs. In order to do this there must be a careful separation of R&D costs from those associated with normal production. The other things the utilities wish to achieve from the project are orientation and experience, both with the plant and the reservoir. No other reservoirs are in use in the Northwest.

There is ample geothermal energy in the Northwest. Its development into an electrical generating capability is based on the schedules of process equipment and resource development. There is a need for all available electrical energy. Cost of this energy for the future may very well be less important than its availability.

NORTHERN NEVADA JOINT UTILITY GEOTHERMAL PROJECT

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Introduction

After approximately eight months of formation discussion between a number of western utilities, a group of five companies defined a project scope, schedule and budget for assessing the prospects for electric power production using Nevada geothermal resources. The project participants are Portland General Electric, Pacific Power and Light, Eugene Water and Electric Board, Sacramento Municipal Utility District and Sierra Pacific Power Co. The project scope defined an "A" phase (Assessment), "B" phase (Design/Constr.) and a "C" phase (operation and further development). Phase "A" began during January, 1979.

Background

The project organization (Fig. 1) is a straightforward arrangement of the participant committee, project manager and three consultants. Schwabe, Williamson & Wyatt was selected as the Legal-Regulatory consultant, GeothermEx/ S. Sanyal were selected to assess the prospective resources and Bechtel Power Corp. performed the plant configuration studies. The participant committee drafted contracting principles and used them to explore each developer's policies and attitudes.

The original phase A schedule called for the resource consultant and participant committee to screen the responding developers to identify the two most promising reservoirs. The Legal-Regulatory and plant configuration consultants would then aid the participant committee in selecting the best single resource for the project. Each consultant would then develop the single site specific details in its responsibility area and together with the contracting efforts of the participant committee would produce a complete project evaluation. A Fourth Quarter '79 Letter-of-Intent between Utilities and producer would begin the process of resource contract negotiation and final project commitment. The completion of a number of participant agreements and beginning of plant detailed design were scheduled first quarter '80 phase "B" activities.

Execution

During May-'79 the participant committee and resource consultant issued a Request-for-Proposal for a 20 to 50 MWe flash steam plant resource supply to approximately thirty Nevada geothermal lease holders. Of the ten developers responding with scheduled northern Nevada development programs, six were seen to be reasonably near term. The project selected four developers operating in three resource areas; Beowawe, Desert Peak and Dixie Valley (Fig. 2). The developer's confidential data packages were evaluated while drilling programs proceeded.

The project resource selection efforts were frustrated by the general immaturity of the reservoir development programs. One relatively unsuccessful drilling program reduced the number of producers to three, but incomplete data packages still plagued the final selection on marginal data during a dynamic drilling period, all three resources would be evaluated in detail and the plant configuration A & E would proceed with their evaluation based on an appropriate range of characteristics. The reservoir assessment cutoff point was extended from Dec-'79 to March-'80, to coincide with the drilling programs, and provide a significant expansion in the reservoir data base.

The A & E was initially asked to develop a single flash 115 psia turbine design and project economic analysis based on the range of parameters representing all three resources. As the reservoir data evaluation and contract discussions progressed, it became apparant that the generally underpressured reservoirs were going to be severely penalized in restricted flow rates to maintain delivery above 115 psia. It became very clear that the generally arms-length coordination between producer and utility was not going to work. The two parties must work together to a considerable degree to achieve good resource utilization and ultimately the lowest cost energy. The A & E ultimately produced a range of designs and evaluations covering several turbine inlet pressures for single flash systems and an 82/16 psia double flash design. Two values for H_2S were also assumed as noncondensible gas data availability was extremely poor.

Results

Complete Legal-Regulatory and "fatal-flaw" level environmental requirements were reported in all areas studied for both resource development and plant operation. Project time extremes are shown for both 10 MWe multi-well plants on private land and 50 MWe multi-well plants on public land (Fig.3). A 10 MWe transportable modular plant with maximum shop fabrication might be on line in 18 months, while a large "poured-in-place" field-erected plant could take as much as 42 months.

The reservoir assessment included geological, geographical scoping data, as available. Historical information on exploratory drilling and observations was compiled. Drilling lithography, well test pressure, temperature and flow dynamics were tabulated, and both reservoir and well-bore dynamic computer simulations were performed on each resource area. Hypothetical sectional reservoir models were provided, correlating all wells and known stratagraphic information. All reservoir production estimates required 80% or greater reinjection for production lifetimes greater than 10 years. Pumped well operation, binary plant application or other techniques may be required in heavy scaling situations and pumped well operation probabilities were cited at all three sites for second generation replacement wells. Geo-chemistry and fluid quality reports were provided from data available on both thermal and non-thermal waters. Resource selection and utilization recommendations were made, reflecting the total of all data gathered and simulated. It is the intent of the project participants to continue to add data to this base as it becomes available.

The plant configuration assessment yielded a considerable range of data. The extremes resulted in approximately \$700/net KW (115 psia, 0 H_2S) and \$900/net KW (82/16 psia, 50 ppm H_2S), excluding some site specific owners costs. The comparisons indicate that for resource contracts based on well production, it is cost effective to configure the plant design to minimize well production requirements. Although H_2S does not appear to be a significant problem, poor non-condensable gas data prompted us to look at the cost impact of a range of values.

As resource contract discussions intensified, it became clear that many developers did not yet have sufficient confidence in their resource to consider large long-term supply commitments. Some targeted 50 MWe and greater supply contracts, but were not ready to start. Others were ready, but related to 10 MWe or 20 MWe agreements at the beginning.

In order to address the full range of contract prospects, the concept of small transportable modular generation units, which had been investigated by several of the utility participants, was integrated into the project in early 1980. The small transportable unit concept has fairly broad appeal for utilities and developers alike.

* Early market commitment before sunk capital constraints
* Cash flow during testing and assessment periods
* Improved early reservoir production data
* Lower Capital risk levels for the utilities
* Prospects for contract simplification and penalty reductions
* Transportable, in the event of a permanent resource delivery problem
* Relocatable to assist in new production zone assessments

The Future

The participant committee is currently negotiating with a number of producers, both in the selected resource areas and in new areas, and anticipate a minimum of 10 MWe on line during 1982 and or 50 MWe or more on line by 1984.

A Letter-of-Intent has been signed by the utility participants to arrange for the purchase of a transportable 10 MWe modular binary generation plant and proceed with the final resource contracting and permitting process.

JOINT UTILITY GEOTHERMAL PROJECT

PHASE 'A'

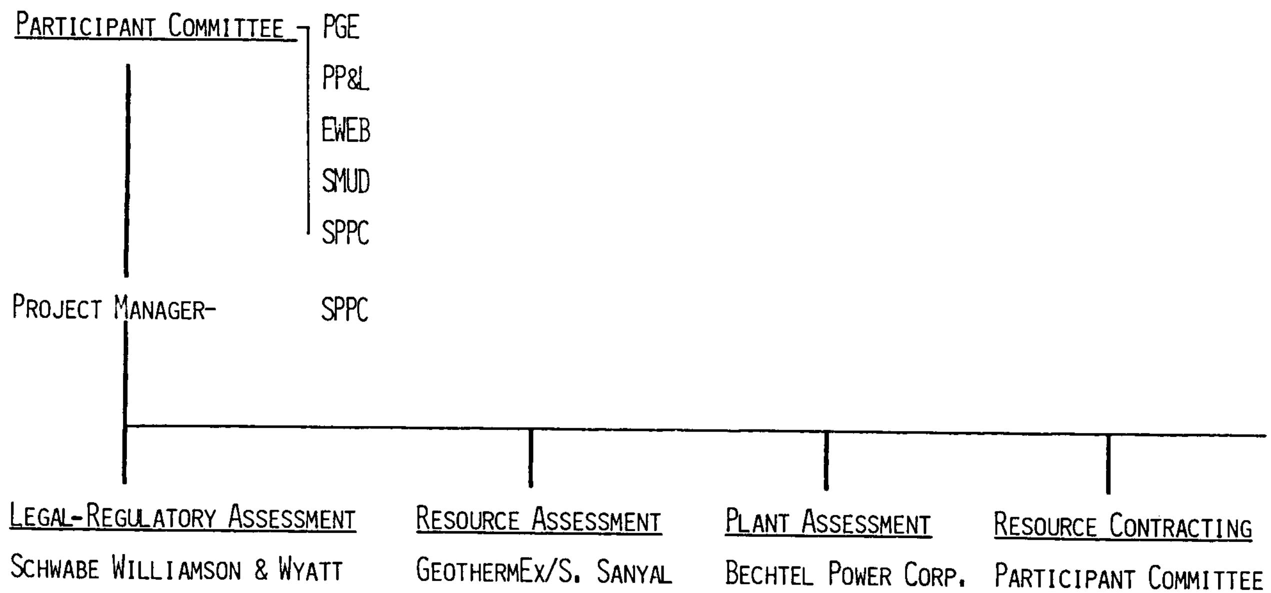

FIGURE 1

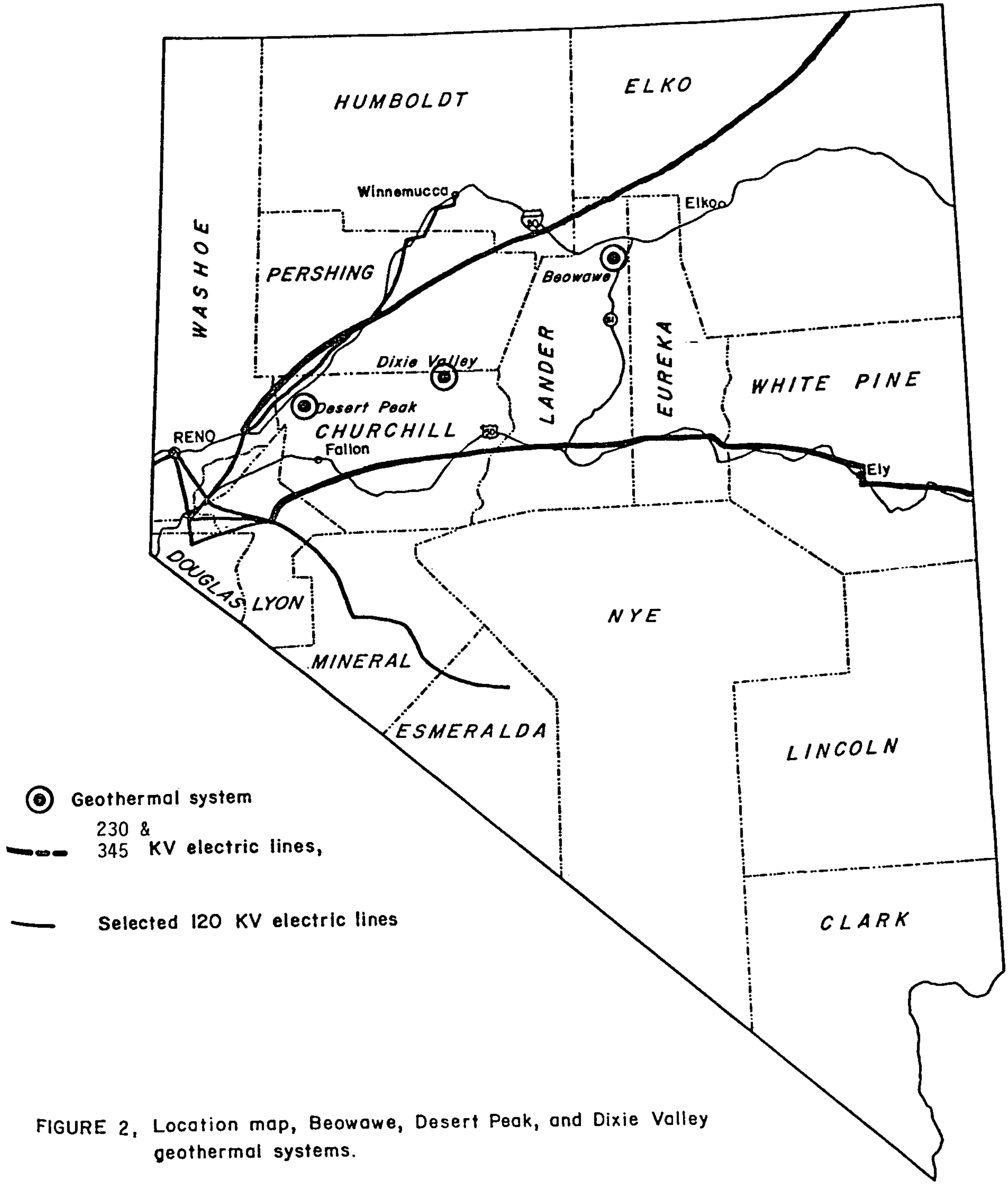

FIGURE 2, Location map, Beowawe, Desert Peak, and Dixie Valley geothermal systems.

JOINT UTILITY GEOTHERMAL PROJECT

PROJECT TIME REQUIREMENTS (NEVADA)

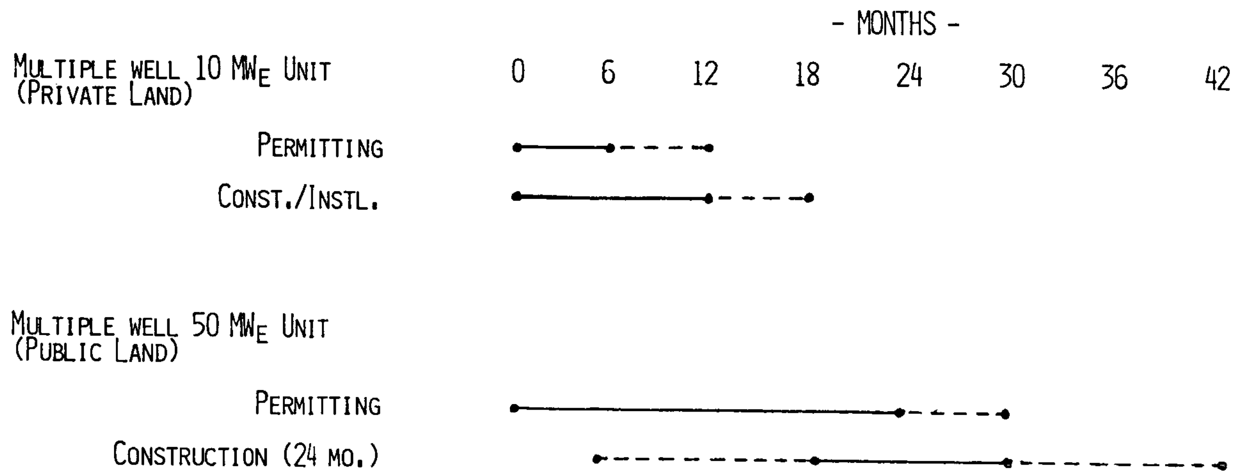

FIGURE 3

JOINT UTILITY GEOTHERMAL PROJECT

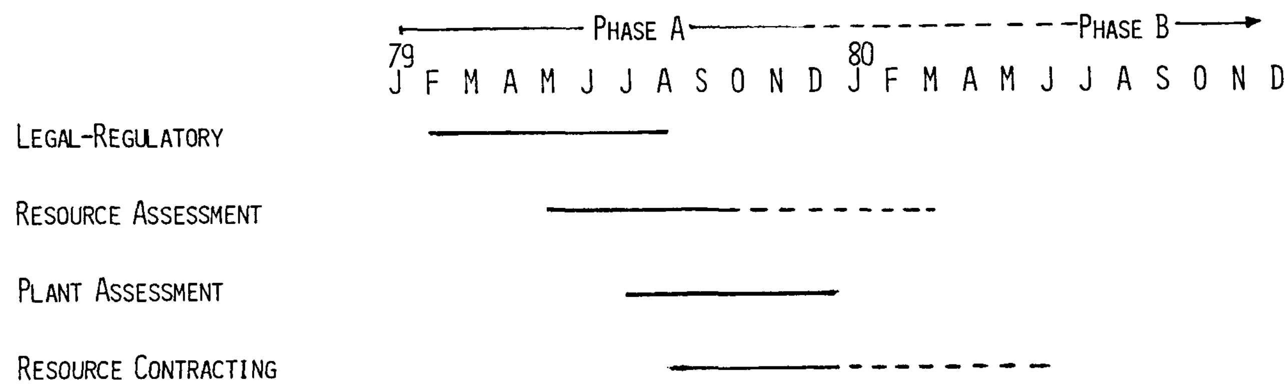

FIGURE 4

Plant configuration comparisons (55MWe gross, 420 F down hole temp.)

Turbine inlet pressure, psia	50	82/16	115	115	115
ppm H_2S in flashed steam	50	50	50	0	300
Steam req., 10^3 lbs/hr	1,100	688/653	930 →		
Brine req., 10^3 lbs/hr	9,100	6,800	13,000 →		
Net unit heat rate, Btu/Kwh	23,800	22,900/40,000	20,400 →		
Project cost, $\$10^3$ (1979)	41,700	44,300	38,000	35,200	42,800

Fig. 5

MEAGER CREEK GEOTHERMAL PROSPECT, BRITISH COLUMBIA
1979 PROGRESS REPORT

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Abstract

The Meager Mountain Volcanic Complex, 150 km north of Vancouver, B.C. has been a target of geothermal exploration since 1974. The study has been carried out jointly by B.C. Hydro, Energy, Mines and Resources Canada and co-funded by the Provincial Ministry of Energy, Mines and Petroleum Resources. Results indicate presence of two geothermal reservoirs approximately 12 km apart (South - North) within permeable fractured quartz diorite basement complex at depths between 1000-2000 m. Three diamond-drilled holes were completed in the South Reservoir area during 1979 and drilling results are compatible with earlier electrical resistivity surveys. The highest temperature recorded was 202°C at 367 m.

Introduction. Geothermal exploration program at Meager Creek was initiated in 1974 by B.C. Hydro and Power Authority jointly with Energy, Mines and Resources Canada. The area is centered around a Pliocene to recent volcanic complex which is located about 150 km north of Vancouver in the Garibaldi Volcanic Belt of the Coast Mountains of British Columbia. Limited access and geographical features restricted the exploration methods and the speed of progress.

Initial work partially identified two independent geothermal reservoirs- the South (or Meager Creek Reservoir) and North (or Pebble Creek Reservoir). The estimated surface area of the South and North Reservoir is approximately 20-30 square kilometres which could potentially represent a development of up to 1000 MW. Work from 1974-1978 has included dipole-dipole and pole-pole resistivity surveys, self-potential surveys, nine shallow and intermediate temperature gradient holes, detailed geologic mapping, geochemical and isotope studies, refraction seismic surveys, microseismic and magneto-telluric investigations. Results of the above studies have been published or are in preparation either by Energy, Mines and Resources Canada or B.C. Hydro.

Recent Work (1979). The South Reservoir, as defined by the previous work, extends from No Good Creek on the west side to the eastern boundary which ends as an outflow plume feeding the Meager Creek hot springs. To the north, the reservoir continues toward Pylon Mountain dipping slightly under the volcanic complex. The southern boundary has not yet been defined. The total area of the South Reservoir is estimated between 8-10 square kilometres (Figure 2).

The 1979 program expanded on earlier data gathered in the Meager Creek area. The main objectives were to confirm resistivity and obtain deeper temperature data; to locate a site for potential flow test well; and to confirm the western boundary of the South Reservoir.

Three intermediate holes were completed with excellent temperature results (Figures 3-5). All holes were 9.6 cm in diameter with 6.3 cm core. The temperature gradients in our most successful hole M7-79D were between 200°C/km and 1500°C/km. The hole reached a maximum temperature of 202.2°C at 367 metres.

Drilling on two of the 1979 holes, M6-79D and M7-79D, was done by a modified Boyles 56A diamond drill rig with high mast and elevated steel platform to accommodate 3000 psi shaffer blow-out preventer (BOP) stack and rotating head. The drill is capable of boring a 10 cm diameter hole to a depth of 1600 metres. With further modifications this type of drilling equipment may play a major role in future geothermal exploration due to its cost effectiveness and portability.

A Boyles 37A without BOP equipment was used to drill M8-79D where temperatures were expected to be less than 100°C. Hole M7-79D, which has standing water at approximately 55 m below the surface, is lined with 5 cm pipe perforated along the lower 55 metres. Hole M6-79D was abandoned after technical difficulties made further drilling impractical. M8-79D is presently being extended.

Work on the North Reservoir during 1979 involved construction of an access road system including two river crossings. Dipole-dipole resistivity was also carried out to upgrade the resistivity information to a similar level as available on the South Reservoir. A total of 25 line-kilometres were surveyed identifying five major resistivity anomalies some of which would become future drilling targets. The Dipole-dipole resistivity is becoming the major geophysical exploration tool at Meager Creek. It is used for preliminary reservoir outline and is important in siting drilling targets. Temperature results in wells drilled to date appear to confirm the validity of the interpretation of resistivity surveys carried out in the Meager area. Other exploration methods which have been employed are temperature gradient drilling and profiling, self-potential surveys, geological mapping and geochemistry.

Other Work. Other related work included isotope studies, slope stability mapping, hydrology, meteorology and air quality studies. The results will be published in the near future.

Recommended 1980 Work The 1980 proposed work will expand on the 1979 results. The work is mainly designed to further define the South Reservoir boundaries and obtain a better understanding of the geothermal system. Also, there is a strong possibility of drilling a steam discovery well in 1980.

In the North Reservoir, the main thrust of the work will be to drill a network of temperature gradient holes to establish the relationship between low resistivity and high temperatures, similar to the work carried out on the South Reservoir.

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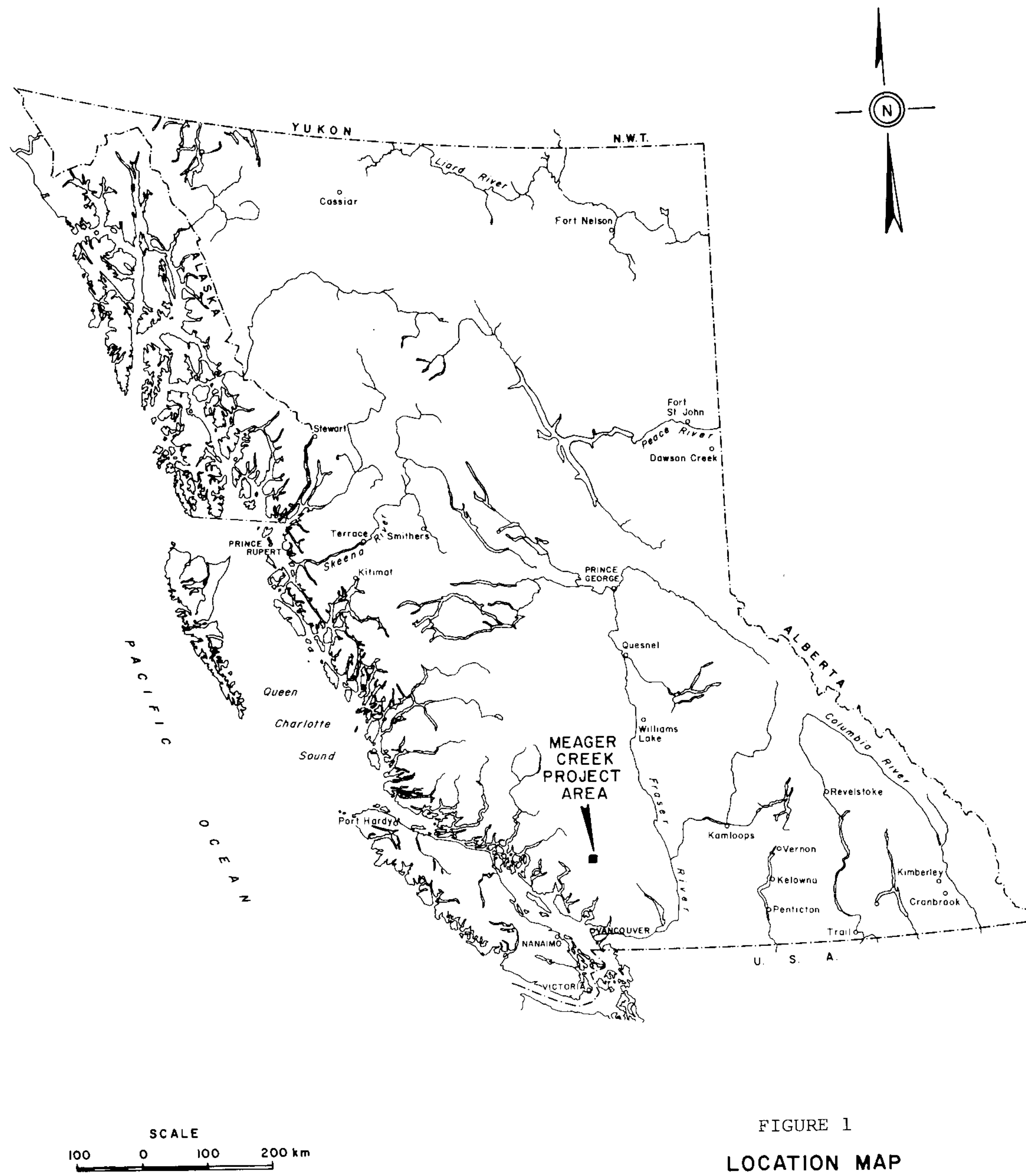

FIGURE 1

LOCATION MAP

MEAGER CREEK GEOTHERMAL

AREA

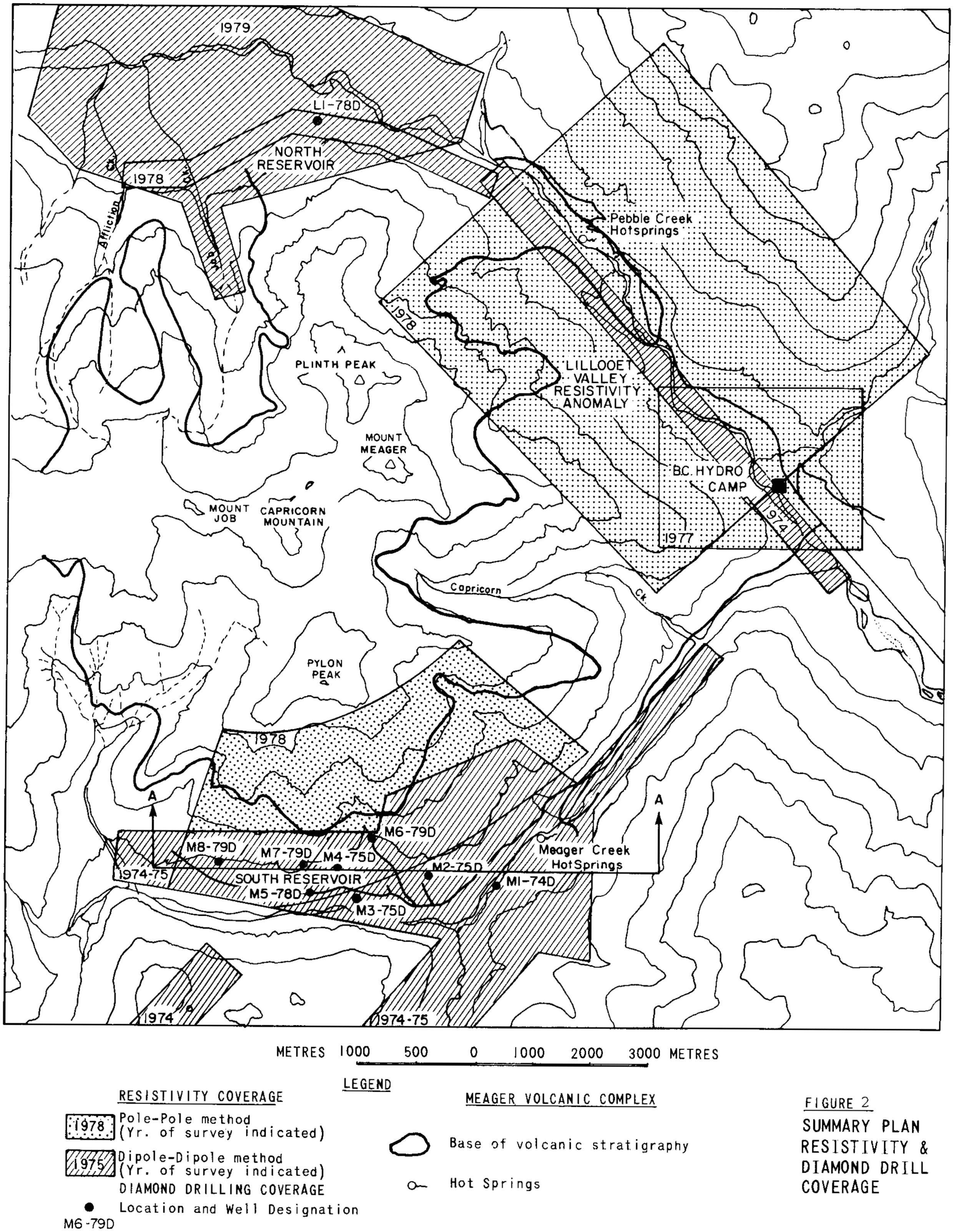

FIGURE 2

SUMMARY PLAN RESISTIVITY & DIAMOND DRILL COVERAGE

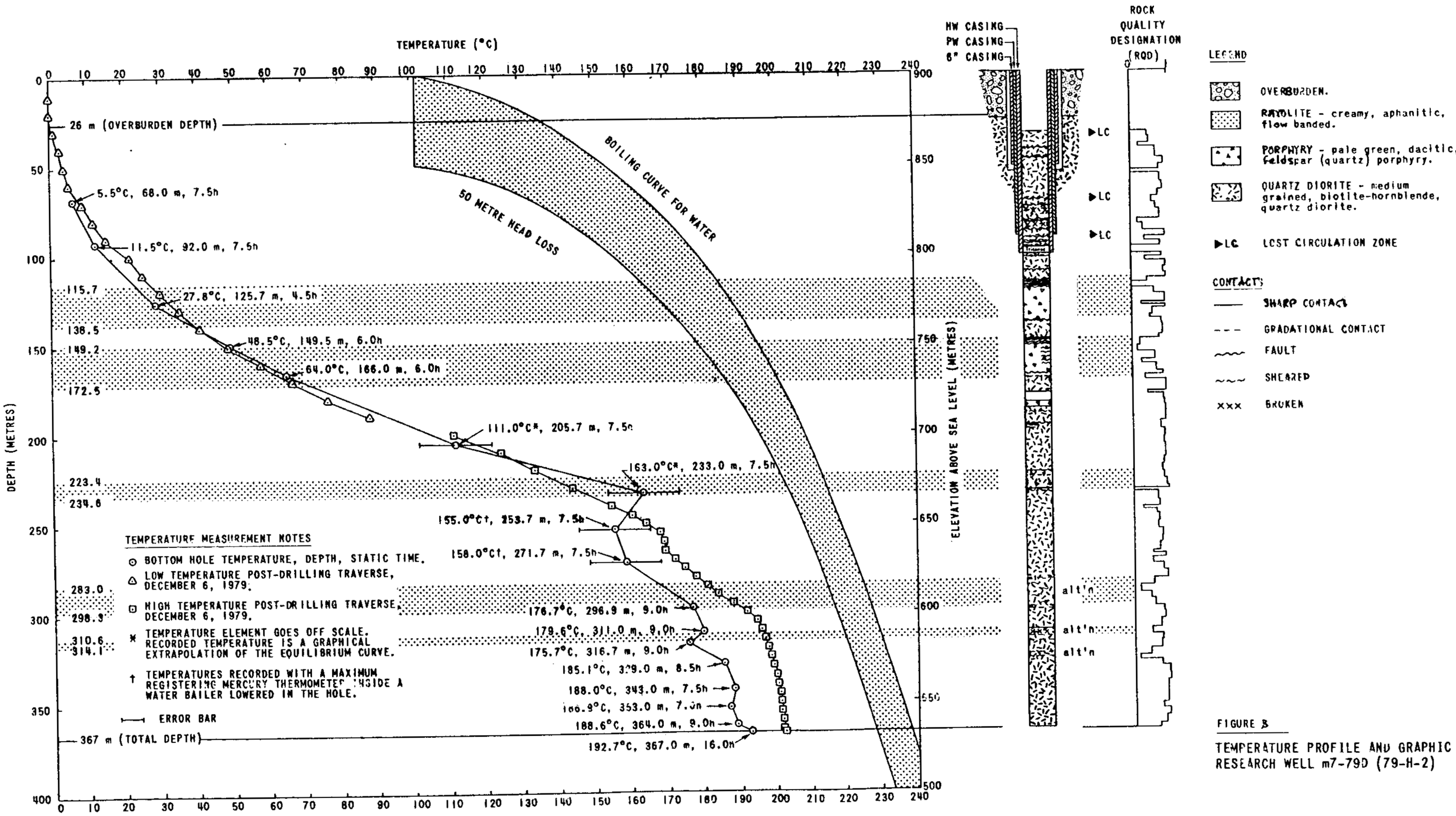

FIGURE 3

TEMPERATURE PROFILE AND GRAPHIC LOG RESEARCH WELL m7-79D (79-H-2)

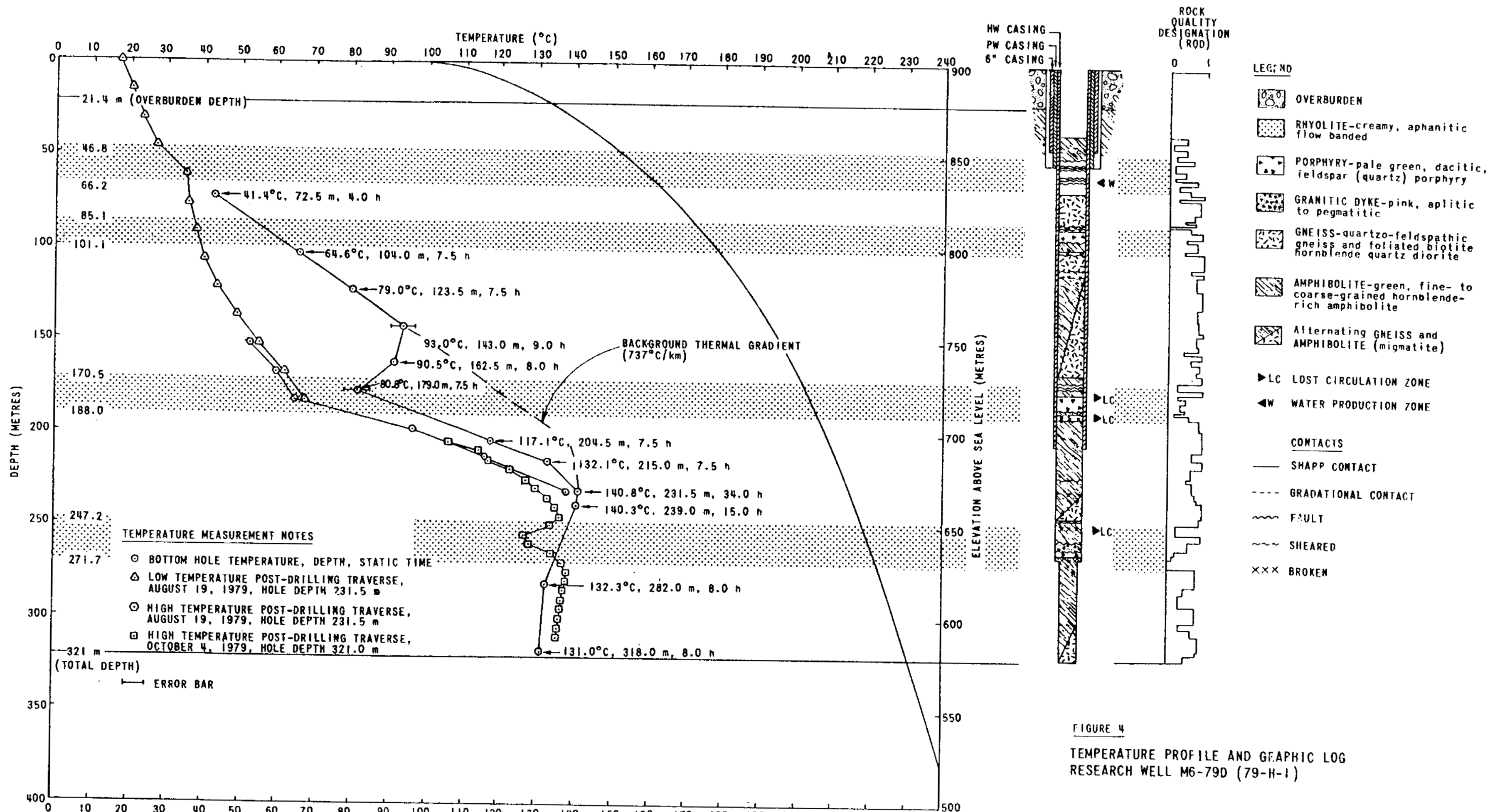

FIGURE 4

TEMPERATURE PROFILE AND GRAPHIC LOG
RESEARCH WELL M6-79D (79-H-1)

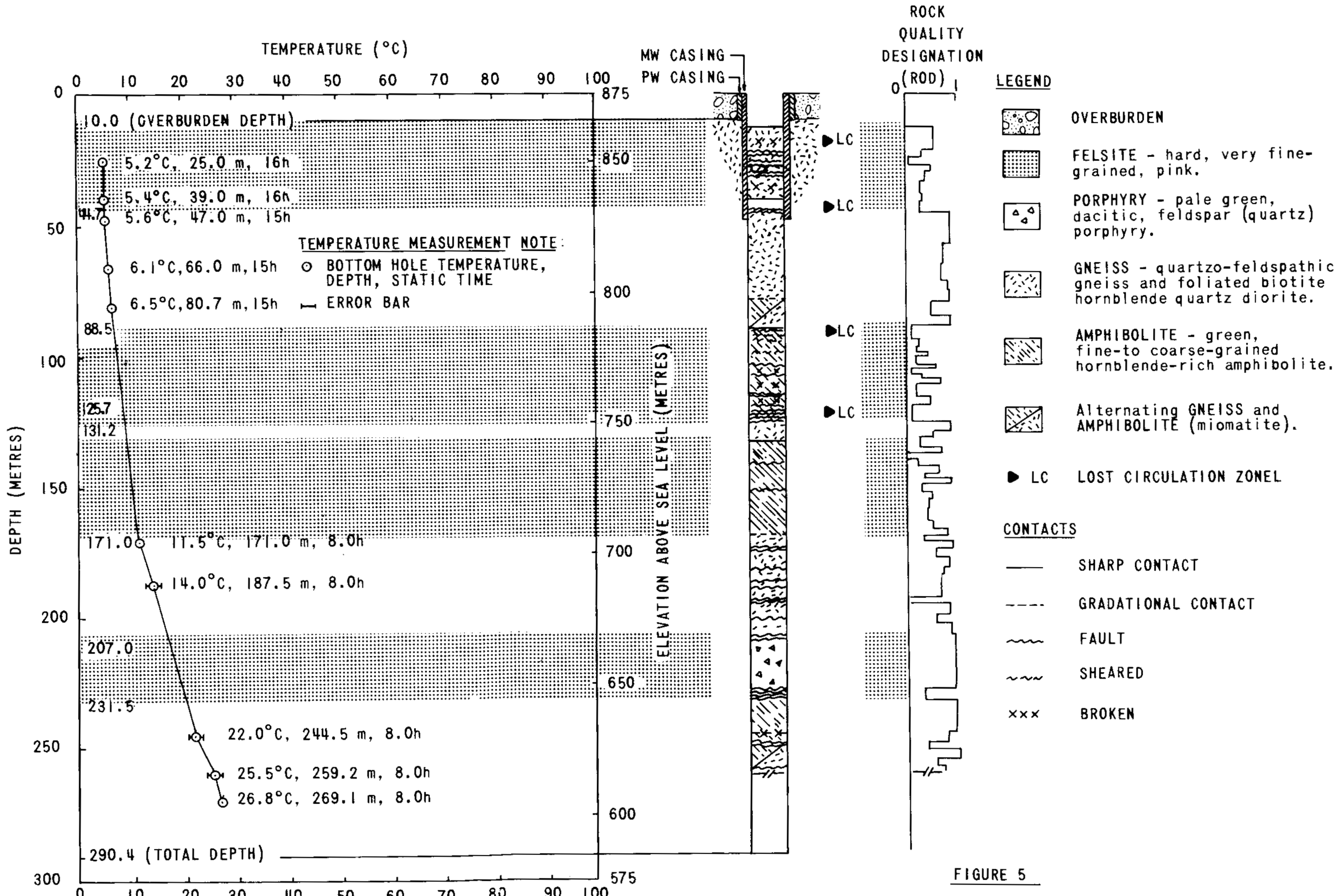

FIGURE 5

TEMPERATURE PROFILE AND GRAPHIC LOGS
RESEARCH WELL M8-79D (79-H-3)

TABLE 1

SUMMARY OF DIAMOND DRILLING (1974-1979)

New Hole Designation	Old Hole Designation	Location	Date Collared (Drilled by)	Depth(m)	Depth of Overburden(m)	Maximum Temperature(^{o}C)	BHT Gradient at Bottom (^{o}C/km)	Comments
M1-74D	74-H-1	South Reservoir Outflow Plume	Nov 74	347	124	68.9	27.7	- making water at 3 l/s - temperature inversion in overburden section
M2-75D	75-H-1	South Reservoir	Sept 75	91	11	15.4	112	- making water at 0.3 l/s
M3-75D	75-H-2	South Reservoir	Sept 75	87	65	35.0	365	
M4-75D	75-H-3	South Reservoir	Sept 75	60	12	20.8	289	- inclined at -70^{o}
L1-78D	78-H-1	North Lillooet Valley	Sept 78	603	47	102.8	211	- temperature inversion between 387 and 450m
M5-78D	78-H-2	South Reservoir	Oct 78	250	250	103.7	n.a.	- temperature inversion in bottom section
M6-79D	79-H-1	South Reservoir	July 79	321	15.6	140.8	n.a.	- temperature inversion in mid section - near isothermal in bottom section
M7-79D	79-H-2	South Reservoir	Oct 79	367	26	202.2	225	- gradient inflection near 300m
M8-79D	79-H-3	South Reservoir	Nov 79	290.4	10	26.8	156	- extension planned for 1980

EDISON'S GEOTHERMAL PROGRAM – 1980 UPDATE

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Introduction In 1975, negotiations were initiated with two major resource developers toward initiating power plant projects at three of the Imperial Valley resource areas, Brawley, Salton Sea and Heber.

The projects at Brawley and Salton Sea are substantially different from that at Heber in objective, size and design. The reasons for these differences are related to the different nature of the geothermal brines and to different operating philosophies of the resource developers involved.

The projects at Brawley and Salton Sea include the construction and operation by Edison of 10 MW (gross) units. The contracts with the field developer for these resources are such that Edison will purchase steam. It is, therefore, the developer's responsibility to drill and complete the geothermal production and injection wells, and to construct and operate the steam separators and flash vessels, brine processing equipment, injection pumps, and steam scrubbing equipment. These units are 10 MW rather than 50 to 100 MW due to the technical risks associated with producing, handling and injecting the very high salinity brines at these locations. In addition, the reliability of turbine operation with relatively impure steam is a major concern.

The Heber plant, on the other hand, will utilize a much cleaner resource. The technical risk is, therefore, judged to be substantially lower. The plant at Heber will be a commercial 45 MW unit. Edison will buy brine, and will own and operate all of the brine handling equipment except for the wells and collection manifolds.

A description of these power plant programs follows.

Based on IEEE Geothermal Power Generation – An Aggressive Utility Program, George K. Crane prepared for presentation at IEEE 1980 Joint Power Generation Conference, Pheonix, Arizona. 9/29/80

Brawley 10 MW Power Plant Project As of this writing, construction of the Brawley plant is scheduled for completion in May 1980. It is scheduled for firm operation during the second quarter of 1980.

It is the objective of the Brawley power plant program to assess the technical feasibility of generating electricity utilizing the high salinity Brawley geothermal resource. The plant design is similar to the proven Geysers units, simple, reliable, and where possible, designed for low capital cost. It is designed to be a model of a full scale commercial plant, using systems and components which likely will be utilized in large scale follow-on units.

The power plant and steam production facilities are located on a 4 hectare, (10 acre) site about 3 km (2 miles) north of the town of Brawley.

The turbine has an output of 10 MW; the plant auxiliary loads total about 1 MW. The net plant heat rate is approximately 28,000 Btu/kWhr. The capital cost of the plant is approximately \$11 million. The total project cost including some costs for prior research work is approximately \$16.3 million. The cost of power generated by the plant is forecast to be about 17¢/kWhr (30 year levelized.)

A few of the notable design features of the project follow:

Steam Condition and Turbine The steam from the supplier is expected be delivered at a rate of 87,000 kg/hr (209,000 lb/hr.) at a single pressure, 800 kPa (115 psia) at approximately saturation temperature of 170 °C (340 °F) with a maximum average .25% moisture, a maximum noncondensable gas level of 2% by weight of steam, and a maximum of 50 ppm TDS including mostly chlorides with some silica. These are obviously very different steam conditions than those associated with high pressure fossil units.

The turbine is a 10,000 kw, 3600 rpm,

single flow, single cylinder unit with five impulse stages, and a design back pressure of 13.5 kpa (4in Hg.) The last stage blade length is 280 mm (11.2 in.) The unit was first conceived as portable; the turbine generator was, therefore, built as a single skid mounted unit installed at grade with a top exhaust and overhead cross-over exhaust duct to a side located condenser.

Condenser & NC Gas Removal As it is desired to retain the steam condensate for process use, a shell and tube condenser is provided. It is a cylindrical vessel with three passes on the water side and a single pass on the steam side. Corrosion resistant stainless steel materials are used because of the oxidation potential of the oxygen and H_2S present in the system.

Approximately 1800 kg/hr (4000 lbs/hr) of NC gasses are drawn from the condenser with a steam jet air ejector requiring 7200 kg/hr (16,000 lbs/hr) or about 8% of the motive steam. Two 200 BHP Nash vacuum compressors with ceramic coated impellors are provided to remove the noncondensables from the first stage ejector intercondenser. A second stage ejector is provided as a backup to the vacuum pumps.

Cooling Water System A conventional two cell, induced draft, counterflow wet cooling tower with a rated heat load of 200 MM Btu/hr provides 870 l/sec (14,400 gpm) cooling water with a 5.5 °C (10 °F) approach to wet bulb temperature.

The tower basin was epoxy coated for protection in the event that the acidic condensate is used for makeup at a later date. Initially makeup at a rate of about 740,000 m^3/y (600 acre ft/year) will be Colorado River water provided to the plant via two alternate irrigation canals operated by the local water district. As the Imperial Valley is a rich agricultural area with a limited water supply, alternative makeup water supplies and cooling systems are being investigated toward minimizing the use of agricultural irrigation water. A candidate approach will be to retrofit the plant with a dry tower to be operated with the wet tower.

Depending on the steam suppliers ultimate need for steam condensate for process use and injection, condensate may become an alternative cooling water makeup source. Another potential source is the high TDS agricultural drain water which will require substantial treatment prior to use as makeup and may also necessitate the use of large evaporation ponds.

The net plant output will be connected to and sold to the local electric utility. Ultimately if the technology proves out, the output of this and follow-on commercial plants will be exported to the Edison system.

Following establishment of firm operation, a one year testing and evaluation program will be performed, leading to a recommendation whether to proceed with a 50 MW or 100 MW commercial power plant at Brawley.

Heber 45 MW Power Plant Project The Heber plant is in the early design phase. The forecast operating date is late 1982. The 11 hectare (28 acre) site is located approximately 8 km (5 miles) south of the city of El Centro. It is the objective of the Heber program to establish a commercial geothermal power plant utilizing the low salinity brines from the Heber KGRA.

The cycle selected is a double flash arrangement. Geothermal brine as a two phase mixture is delivered to the Edison plant at a temperature of 140 °C (290 °F) and a maximum pressure of 410 kPa (60 psia) at a rate of approximately 3,600,000 kg/hr (8,000,000 lbs/hr). The brine is piped to a first stage brine/steam separator operating at 380 kPa (57 psia). The steam is piped to the front end of the turbine. The unseparated brine from the first stage separator is then flashed in a second stage vessel producing steam at 110 kPa (16 psia) which is directed to the low pressure turbine stages. Two parallel strings of 50% capacity separator/flash vessels are planned.

The steam separators and turbine generator were purchased under a single order.

The turbine has a rating of 52 MW (gross) at a 12 kPa (3.5 in. Hg) back pressure and is being designed as a single cylinder, double flow bottom exhaust unit operating at 1800 rpm.

Condenser/NC Gas Rmeoval A shell and tube condenser will be provided. First stage NC gas removal will be accomplished with a steam ejector with a vacuum pump provided for second stage removal. Because the H_2S and other noncondensables are at such a low level at the Heber reservoir, no special treatment will be required.

Cooling Water System The steam condensate at the Heber plant is retained by Edison and is used for cooling tower makeup. Since 100% injection is required at Heber, approximately 3.7 million m^3/year (3000 acre - ft/year) of nearby river water will be injected into the reservoir. To avoid plugging of the injection wells, this makeup injection water will undergo treatment prior to injection. A conventional 10 cell induced draft wet tower will be used for heat rejection.

It is planned that the output from the Heber plant will be exported to the Edison system through a soon-to-be-closed intertie with the Imperial Valley utility. Electrical power will be generated at 13.8 kv and then stepped up to 34.8 kv to tie into the utility grid.

The anticipated heat rate of this unit is 30,000 Btu/kWh based on preliminary heat balances. The plant capital cost is estimated at $69 million. The levelized power cost, (1982 basis) is projected to be approximately 18¢/kWh based on a 75% capacity factor. For comparison this figure is close to the cost of oil generation but is substantially higher than an equivalent figure for new coal generation.

Salton Sea 9 MW Power Plant Project Since this project is similar to that at Brawley and is now only in the early design phase, its design will not be discussed in detail. There are, however, several noteworthy differences between this and the Brawley programs.

The Salton Sea KGRA is believed to be the largest and hottest of the Imperial Valley resources; it would appear therefore to have the highest commercial value. Unfortunately, however, numerous well tests have shown it to have the highest TDS level brines, some up to 300,000 ppm.

As mentioned, this area was the first Imperial Valley resource which Edison attempted to develop. During this early development effort, Edison's wholly-owned fuel resource development subsidiary, Mono Power Co., became an undivided 25% owner of about 10,000 hectares (25,000 acres) of geothermal leases. As such, they are participating with two other lease owners in a field development research program to determine the best method to handle the brine and produce steam. To date, four wells have been drilled, and a system including flash tanks, steam condensers and an injection system has been constructed and operated. This program will lead to the design and construction of facilities which will provide steam to the Edison plant.

Some unique structural design considerations may be required as the plant site is surrounded on two sides by, and is immediately adjacent to, the Salton Sea. The sea is rising at a rate of several inches per year; the plant site is now several feet below sea level and is protected only by earthen dikes. The water table is kept below grade by an agricultural tile drain system. The suitability and reliability of these dike and drain systems will have to be assessed in light of the substantial plant investment they may be called upon to protect.

The economics of the Salton Sea plant are forecast to be similar to those of the Brawley Project; the scheduled operation date is July, 1982.

Related Geothermal Activities In addition to these three power plant projects, Edison is pursuing a number of corollary activities including resource exploration and assessment and new technology assessment.

Resource Exploration Edison's subsidiary, Mono Power Co., is involved in a continuing program of resource exploration and assessment. In addition to participation in developing the Salton Sea resource, Mono is working with another resource development company in exploration and leasing of geothermal prospects in areas of California outside the Imperial Valley. Together they own several thousand acres of leases at various sites in the Mono/Long Valley area.

When Edison is approached by "third party" resource developers with offers to sell Edison geothermal steam or hot brine, Mono's staff geologists perform analyses of the resource in terms of its potential size and quality, and prepare recommendations as to whether Edison should pursue the prospect. This "in-house" "below ground" expertise is an invaluable complement to Edison's geothermal utilization activities.

Technology Assessment Through participation with the Electric Power Research

Institute monitoring of the U.S. Department of Energy's geothermal program, and contact with numerous individuals and companies, Edison maintains awareness of, and in some cases participates in the development of new technologies or new applications of existing technologies for geothermal utilization. For example, Edison intends to participate in the construction and testing of the 50 MW binary cycle demonstration power plant to be constructed near Edison's flashed steam plant at Heber.

Other new technologies for geothermal include improved and advanced steam separators, mixed phase expanders as prime movers, direct contact heat exchangers, down hole heat exchangers, upstream (of the turbine) and downstream H_2S removal systems, as well as systems to utilize hot rock and magma where water is not present for heat transport.

EXPECTED RESULTS

As the three Edison plants and those developed by others come on line and are operated for several years, critical issues will be monitored and assessed including:

- Turbine reliability as a function of steam purity
- Power plant O&M costs
- Steam supply system equipment reliability
- Reservoir temperature/pressure degradation
- Overall plant efficiency
- Subsidence
- Air quality
- Water consumption
- Noise
- Busbar energy cost

With positive results from these programs, water dominated geothermal systems can provide hundreds and perhaps several thousand megawatts of baseload generation in Southern California in the next two decades.

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SESSIONS 5 AND 6

WORKSHOP:

LEARNING FROM POWER PLANT PROJECT EXPERIENCE

REPORTS OF WORKSHOP DISCUSSION GROUPS

EAST MESA
MAGMAMAX POWER PROCESS
GEOTHERMAL GENERATING PLANT
A PRELIMINARY ANALYSIS

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I. Introduction During recent months, Magma Power Company has been involved in the shakedown and startup of their 10 Mw binary cycle power plant at East Mesa in the Imperial Valley of Southern California. This pilot plant has been designed specifically as an R & D facility, with its primary goal to explore the necessary technology improvements required to make the binary cycle an efficient, cost effective and reliable conversion process.

Magma Power's exploration activities, carried out in other parts of the Western United States after the initial discovery and development at The Geyser's, gave evidence that The Geyser's type of steam reservoir was unique and that the majority of geothermal resources would be of the hydrothermal, or pressurized hot water type. Initial flow tests throughout different locations where this type of resource was discovered indicated that well bore scaling occurred at the flash point in the wells. Initial evaluations indicated that if the well fluid could be maintained under pressure as it traversed the well bore, the potential for scaling would be mitigated. Tests carried out in the late 60's at Magma's Brady Hot Springs development in Nevada indicated that scaling was mitigated with the installation of a pump in the geothermal well.

Subsequently, designs were developed of a binary process, utilizing heat exchangers for power generation. Magma was able to acquire process patents associated with this and had a patent issued (Magmamax Power Process). This incorporates the concept of pumping a geothermal well and transferring the heat in the geothermal fluid to a secondary power fluid in heat exchangers. Magma's desire to demonstrate this technology was one of the prime motivations associated with the installation of the East Mesa plant.

Necessarily, much of the equipment and application methods being utilized are new and innovative. Realizing that efficiency improvements and reduced auxiliary power requirements are critical influences on final busbar costs, Magma has supported the philosophy of incorporating innovative ideas into working hardware in their pilot facility. Operation to date has been predictably spasmodic, as technical problems relating both to the plant and the reservoir have been identified and solutions are being worked out and implemented. The plant has operated up to a gross output level of about 7 Mw, and has sustained periods of continuous operation (several weeks) at a 3 to 4 Mw level. Since there has been a certain amount of speculation in the industry about the nature of our initial difficulties at East Mesa, we feel it would be of value to discuss the preliminary experiences to date, outlining first how we "arrived" at where we are today by relating some project history and design philosophy, and finally reviewing some of the preliminary operating experience.

II. Project History When this plant was first conceived the site for the plant was to be Brady, Nevada. The brine at Brady was approximately 325^{o}F and relatively clean. Later the plant site was switched to Mammoth, California where brine conditions were a little hotter than Brady. Both of these locations were abandoned for several reasons.

In September of 1975 Magma obtained 5,000 acres of the East Mesa Known Geothermal Resource Area (KGRA) in being the successful bidder for the southern area of the field when the lease sale was initiated by the Bureau of Land Management. In early 1976 two deep test wells were drilled and subsequent flow tests with a diesel driven pump indicated that the reservoir conditions at this particular location in the East Mesa field would be ideal for testing and demonstrating the Magmamax Power Process.

The initial exploration wells were jointly funded by Magma and its Imperial Valley partner, New Albion Resources Company. Magma subsequently entered into an agreement with New Albion Resources Company that allowed Magma to develop the first 65,000 Kw of power generation at the East Mesa field on their own. This set the stage for Magma to initiate the project. J. Hilbert Anderson, Inc. was selected to do the detailed engineering of the project and purchase the major equipment for Magma's account. The Anderson organization had been associated with Magma throughout the development of the Magmamax Power Process.

Another motivation for the construction of the plant was to develop reservoir information on Magma's leases in the East Mesa field to provide confidence to allow major power plant construction to be initiated. There have been many academic studies made of the East Mesa reservoir and indications are that there is a significant potential for development. However without concrete well production information and long term testing the confidence level associated with reservoir productivity and potential is relatively low. Magma was confident that there would be an adequate resource to provide the necessary volume of fluid for the small pilot plant and therefore made no attempt to assess the potential of the reservoir, knowing that this would be a fallout associated with the operation of the project.

In the fall of 1976 the final engineering was initiated. In the spring of 1977 the information necessary to be filed with the Federal government was completed and submitted to the office of the Area Geothermal Supervisor of the United State Geological Survey. A field trip was scheduled in July of 1977 by USGS for interested parties to view the site. The environmental section of the USGS geothermal group completed, and submitted for review, the draft environmental analysis in September 1977. The contractors for the construction of the project were selected during the fall of '77, the construction permit was obtained from USGS in early January of '78 and field construction was initiated immediately thereafter.

Plant construction was completed in mid-1979 and initiation of preliminary checkout activities prior to startup followed. During the initial operations the project was plagued with more than its share of mechanical failures, earthquakes and the like which caused initial power generations to be delayed until February of 1980. Several improvements have been made to the plant. Some improvements have been based on improving reliability of equipment and others have been made to enhance equipment performance. At the present time (spring 1980) the project is fully operational with the exception of the propane system. The propane system remains to be flushed and checked out prior to startup of that system's additional power generating capability.

III. Permits Since the project was associated with the Federal Leasing Act the Federal government was the lead agency of the project. The Bureau of Land Management is the lessor; however they have yielded to the United States Geological Survey for the purposes of administrating the lease provisions on Federal lands for geothermal development. Early in the discussions with the Federal agencies it was recognized that the Magma plant would be a pioneering effort in permitting, since it would be the first operating geothermal plant on Federal lands. At the time that the project was proposed, the Bureau of Land Management had only yielded to the USGS for administration in the matter of drilling wells and production testing. Therefore, discussions were necessary to determine if the Bureau of Land Management would be the lead agency for the power plant or if they would, in turn, continue to use USGS in that role. A final resolution was made and adopted orders were established indicating that for projects which were 25 megawatts or less and were research and development in nature, the USGS would be the lead agency for the power plant construction. If the facility being proposed was larger than 25 megawatts the Bureau of Land Management would be the lead agency associated with licensing of the power plant.

A Plan of Utilization was prepared by Magma for presentation to the USGS to identify the project for the purposes of writing an environmental assessment. Since the project was on Federal lands, the USGS environmental section in the Area Geothermal Supervisor's office was assigned the responsibility for writing the environmental assessment, having input from the operator in their plan of utilization. A companion plan required by the operator is a plan of production which identifies the well operations associated with the project. In the regulations associated with this there is a requirement that environmental baseline data be presented as part of the plan of production. The environmental baseline information has to be acquired for one year prior to the initiation of production. The USGS has established guidelines for the acquisition of environmental information. The Department of Energy had sponsored, through Lawrence Livermore Laboratory, the acquisition of baseline data in the Imperial Valley as part of an overall Imperial Valley project. The LLL group had acquired a considerable amount of environmental data in the East Mesa area and the bulk of the requirements associated with the USGS guidelines was provided by the Lawrence Livermore Laboratory project. An unfortunate situation associated with this was that the specific format of some of the aspects of the LLL data acquisition did not satisfy the specific requirements of the USGS environmental data base guidelines. Negotiations with the two Federal agencies were required to provide the information in a format that was satisfactory to the responsible agency.

One of the frustrating aspects of initiating a project associated with an environmental review is determining which are the specific organizations that are required to "sign off" on the project. The project was delayed for a period of time before the final permit issuing because it was overlooked that the State of California State Historical Preservation Officer had some jurisdiction associated with the particular method in which archaeological artifacts were to be collected and disposed of. This required a series of meetings and discussions between the USGS offices and the SPHO offices to resolve the differences so that a permit could be issued. One of the difficulties associated with the archaeological review is that an investigation is required prior to issuing permits to determine if there are archaeological artifacts which require collecting. However, the collection of these artifacts and cataloging of them cannot be done until a permit is issued. Something should be done that would enable the artifacts to be collected very shortly after the time that the initial survey has been done. If long delays occur, a completely new survey is often required and a different set of artifacts to be collected is established. This survey then does not correlate entirely with the surveys that were done at the time of the initial work. To avoid future confusion, Magma had a survey and collection made of the entire section that the plant is incorporated in so that if expansion is carried out in the future there will not be a requirement for additional artifact collection.

Another aspect that required some pioneering associated with the licensing for the plant was that of relations between the local agency (County of Imperial) and the Federal agency. Initially the County of Imperial took the position that the developer would be required to obtain a conditional use permit from the County Planning Commission. It was ultimately resolved that this would not be required. The County of Imperial would input their assessments associated with the project to the Federal agency. The Federal agency would in turn respond to this, and incorporate it into their permitting requirements and environmental analysis.

An agreement was reached that inspections and permits associated with excavation and buildings were to be provided by the County Building Department but inspection associated with everything else on the project would be carried out by Federal personnel. Also the local Air Pollution Control District was utilized for the permitting associated with air emissions, and the California Water Quality Control Board was utilized for permitting of the water discharges from the plant. Therefore, permits were issued on the overall project by the USGS, excavation and building permits were issued by the County of Imperial, the Air Pollution Control District permit was issued by the local APCD agency and the water discharge permit for the blowdown from the cooling system was issued by the California Regional Water Quality Control Board.

IV. Design Philosophy Being intimately familiar with the technical difficulties associated with flashing a well, we decided to move ahead with the development of a vapor turbine power cycle. Because of ever escalating drilling costs, it was imperative that the energy extracted from each pound of brine be maximized. The plant was to be well instrumented in order to learn as much as possible for the design of larger plants. The principal goal would be to gain information useful in optimizing the economics of such larger plants.

It was expected that there would be a number of technical uncertainties associated with the design of an entirely new system. First of all, the wells were to be pumped, as opposed to allowing the brine to flash to steam. Pumping offers certain advantages. For a given size well, more energy can be recovered by pumping than by free-flowing. In essence, a mechanical pump is a great deal more efficient than a steam lift pump. Pumping the well, however, presented the technical difficulty of handling hot brine. Existing deep well pump technology certainly left a lot to be desired.

Since we would use pressurized fluid from the wells, designing a power cycle using a tapered heat source was a challenge requiring innovative cycle design.

Since the geothermal brine contained various dissolved minerals and gases, the question arose as to what deposits, if any, would collect on the heat exchanger tubes, piping, and associated brine equipment. In choosing to use heat exchangers it might be inviting a difficult cleaning problem. In addition to unwanted deposits, we did not know the degree of corrosion that might be encountered.

Construction of the heat exchangers alone would be a significant design achievement. This is not to say that heat exchangers handling hotter water and more corrosive fluids have not already been built, but for this particular application, a substantially large surface area would be required. Whatever the heat exchanger configuration might be, we knew we had to cope with a thermal expansion difficulty. This would require particular attention so that the heat exchangers would prove to be reliable. The proper combination of materials, tubes, tube sheets, and expansion devices would have to be closely and carefully designed. The heat exchangers would have to be designed in a way that would permit them to be easily inspected and cleaned if necessary.

Isobutane was selected as the primary working fluid. From a thermodynamic and cycle performance standpoint, this fluid appeared to be best. However, in handling isobutane there would be some technical uncertainties that would have to be incorporated into the design. Isobutane's thermal properties were not completely established. The best data available would be used, but there would still be some question about the accuracy of the properties. We would have to handle high velocity, dense gas flows throughout the loop. The heat exchanger sealant materials and joint designs had to be capable of preventing brine leakage into the isobutane circuit. Segregation of liquid in the boiling regime and balancing of the heat exchangers would be a potential problem. This had to be carefully analyzed to insure proper heat exchanger operation.

The isobutane turbine would be a new piece of equipment. A specific isobutane turbine was not anoff-the-shelf item. The problem of designing a turbine with no prior testing available had to be faced. The turbine would have its own thermal expansion, sealing, materials, and bearing problems. Pumps, valves, and other hardware components had to be carefully selected.

Probably the most significant technical hurdle was how to dispose of large quantitites of heat to the atmosphere. This is quite simple when a large cool river is flowing nearby. Unfortunately, many geothermal areas are not near such sources and therefore, other means of disposing of heat would have to be found. The difficulty of disposing of heat to the atmosphere is magnified because of the fact that the geothermal source is basically a low temperature heat source. It is well known that as the temperature difference between the high temperature source and the low temperature sink in a thermal power system decreases, the quantity of heat that must be disposed of to a low temperature sink increases significantly (Carnot cycle efficiency). Consequently, in a geothermal plant using approximately 300°F source water almost six times as much heat would have to be disposed of as would be required in a coal or oil fired plant of the same size operating at high temperature and pressure. Cooling systems are indeed a very costly and important engineering consideration in the design of a relatively low temperature geothermal power plant.

Many technical uncertainties would be associated with the construction of the plant itself. The contractor would be constructing something unlike anything he had ever constructed before. In a cycle such as this, it would be necessary to keep dirt out of the system and there would be numerous special construction considerations which would have to be observed.

It was recognized that we faced a number of hurdles in designing a reliable and economic power plant. As a result there are a number of innovative approaches that have been taken to accomplish our objective. It was recognized that existing well pump technology may not be adequate for these hot water wells. Nevertheless, we included the task of pump development in our test program, knowing that the only way to solve this problem was to test hardware under actual operating conditions. Preliminary pump testing with modified conventional water well pumps had established a reasonable chance of success, and we realized that there were new methods of well pumping being developed which may improve reliability. The useful energy that could be obtained from a given well by pumping the well compared to flashing the well,as well as mitigating downhole scaling, prompted this decision.

The next major innovative approach was to keep the brine under pressure thru the heat exchangers and into the reinjection wells. This has several distinct advantages. By keeping the brine under pressure, carbon dioxide would not be released. This means that the dissolution of carbonates on the heat exchanger tubes should be lessened. Other gases as well could remain in the brine so that we would not have a gas disposal problem to deal with. By keeping the brine side under pressure we would be able to keep air out of the water and therefore reduce the possibility of corrosion. Another advantage to keeping the brine under pressure is that the heat exchanger tubes could have thin walls, since the pressure difference between the working fluid and the water would be reduced. A major difference between the heat source for this plant and for a conventional power plant is that it is a "tapered" heat source. This means that the temperature of the brine would drop continually as heat is removed during its flow thru the plant. Tailoring a system to this tapered heat source required considerable effort in the design of the cycle and its associated heat transfer equipment.

After much analysis of existing heat exchanger equipment and "off-the-shelf heat exchangers" we ended up designing our own. They are of the true-counterflow type with a relatively small pressure difference from the brine side to the power-fluid side. The pressure drop on both the power-fluid side and on the brine side was much lower than would normally be encountered in a heat exchanger of this size and type. The long, small-diameter heat exchangers were designed with new tube supports and unique tube sheet joints. Special tooling was designed and built to produce the tube supports and to attach the thin-wall tubes into the tube sheets. At least one end of the heat exchangers would have to be floating or be capable of taking expansion. The heat exchangers, approximately 70 ft. long, would definitely have to be able to handle thermal expansion and contraction. As mentioned above, the heat exchangers would have to be capable of being cleaned on the brine side. This meant that the shell would have to be removed or the tube bundle would have to be extracted. Batch cleaning of the brine side is a possibility.

Isobutane was chosen as the power fluid. Thermodynamically it appeared to be the best choice. We recognized, however, that it is a flammable gas and we would necessarily have to provide additional safety and fire protection equipment. Throughout the entire cycle, isobutane would be above atmospheric pressure so there is no danger of air entering the system.

Choosing a power turbine for the isobutane was a sensitive engineering consideration. Unfortunately, most of the "off-the-shelf" expanders had certain disadvantages for utilization in this cycle. One major consideration was that the turbine had to have an effective shaft sealing system. Furthermore, it must be tight at shutdown. Although such a sealing system is standard on refrigeration-type turbomachinery, it was not available in expander-type turbomachinery. In addition to driving the main generator with a power-fluid turbine, it was decided to also drive the boiler-feed pump with a power-fluid turbine. In this type of power cycle, there is a significant advantage to using power-fluid turbines to drive as many of the major pieces of auxiliary equipment as possible. Besides increasing the overall efficiency of the cycle and providing the advantages of variable speed drive, this approach also reduces the electrical parasitic losses. Magma decided that it was important to gain design, application, and operating experience with this type of subsystem, and the main cycle boiler-feed pump drive was chosen as the best testing location. In larger plants, additional power-fluid turbines would be used to drive additional equipment like cooling water and condensate pumps.

The decision was made to design the isobutane turbines and have them built to our specifications by a refrigeration turbomachinery manufacturer. Several design innovations were incorporated into the turbines. Both the main and boiler-feed pump turbines drive their ultimate loads thru speed-reducing gears. In future, larger plants, the turbines will probably be direct-coupled to their respective loads, either operating at generator speed or having internal gears to provide the proper drive shaft speed. For this small pilot facility, external gear boxes are used.

Another important innovation in the turbine-gear design was the utilization of a quill shaft and disk type coupling. The quill shaft permitted the use of the smallest possible mechanical shaft seal. Furthermore, the quill shaft is an extremely good torsional isolator. The flexible disk elements transmit no thrust to the turbine from the gear. The coupling, which runs between 6,000 and 7,000 rpm, is non-lubricated, easily removed, and is virtually maintenance free. It will also operate at considerably more misalignment than any other high-speed coupling. The power fluid turbines utilize a shaft mounted oil pump and internal lubrication system.

To gain further efficiency in the process it was decided to incorporate an additional hydrocarbon loop into the system. Very simply, this amounted to two separate Rankine cycles operating off the same heat source. The specifics of the cycle are discussed elsewhere in this paper. Propane was chosen as the working fluid in the lower temperature cycle. This cycle is referred to as a "dual fluid" cycle and is essentially a "bottoming" cycle.

The dual-fluid cycle required a heat exchange between the isobutane and the propane cycles. A radically new recuperator was conceived that permits phase change and excellent heat transfer with a minimum of pressure drop. Once again, the design of this particular heat exchanger required considerable innovation in terms of the shell design, tubes, and tube supports. The exchanger was designed by us and built to our specifications.

An overall design consideration throughout the entire engineering approach was to maintain parasitic losses as low as possible. This meant that particular care must be given to piping, valves, auxiliary systems, turbine efficiency, etc., in order to minimize overall plant losses.

One of the major design innovations is the heat rejection system. It was designed to use a minimum amount of power to provide cooling but also to permit the highest plant output in the afternoon hours when the utility power requirement is highest. This system is designed with thermal peaking. It provides the coldest cooling water in the middle of the afternoon. The coldest water possible is produced under nighttime atmospheric conditions. The cold water would be spray-cooled at night and then be stored in a deep stratified pond for use in the middle of the afternoon. This system coupled very well with using isobutane and propane as working fluids because the heavy molecular weight fluids permit the use of small turbines. By achieving lower condensing temperatures, turbine output power can be significantly increased. The spray system needed to be designed to be particularly efficient in transferring heat to the nighttime air. Once again, the primary objective was to test a system which has the capability of producing the most cooling with the minimum expenditure of power.

A complete study of the daytime and nighttime atmospheric conditions was made for East Mesa before proceeding with a detailed cycle and cooling system design.

The water table was quite close to the surface and handling of water in the Imperial Valley is a very difficult and sensitive design problem. We had to be very careful not to mix certain water flows or contaminate the ground water. Testing of the jet spray and thermal peaking heat rejection system was included even though we knew that high winds and soil conditions would make this difficult. The importance of obtaining the lowest possible sink temperature needed to be evaluated.

It was with these and other innovative design approaches that we have developed a pilot plant to test the technical and economic viability of the binary cycle as a conversion process for liquid dominated geothermal resources. This plant, by demonstrating these innovative approaches, will then provide a data base for future, larger plants.

V. Plant Description The East Mesa pilot facility employs a "Dual-Fluid Cycle", in that it uses two organic fluid loops to convert the geothermal heat to motive power. Excess heat from each power fluid is rejected to an advanced jet spray/pond cooling system. Figure 1 illustrates the dual fluid, closed Rankine system.

A. Process Flow - In the descriptions that follow, it must be stressed that the numbers presented reflect average operating conditions. Each well site, for example, will encounter varying conditions of brine chemistry, temperature, flow, and required pumping pressure.

Geothermal brine (805 GPM, 360°F) is pumped at 196 psia from each of four production wells. One additional well has been drilled for standby duty. The five production wells are located on two drilling sites; site separation is approximately one-half mile. Average well depth is 7,500 ft. A single 12" line from each site carried the brine to the plant where it combines, flows through a sand separator, and then is pressurized before entering the heat exchanger field. At the exit of the heat exchanger field, the cooled brine (180°F) flows to the injection pumps where it is pressurized and sent to the injection wells. Three injection wells have been drilled; one for standby duty.

Isobutane liquid is heated, vaporized, and superheated in the heat exchanger field by the geothermal brine. The liquid is heated during its series travel thru six of the ten true-counterflow heat exchangers. It then splits into two parallel flows, each flowing thru a boiler and a superheater before passing into the Knockout Drum (345°F, 500 psia). After passing thru the Knockout Drum, the gas is expanded thru each side of the dual 3-stage tandem turbine. Extraction gas from the main turbine is used to drive the boiler feed pump turbine. Exhaust gas from each unit of the main turbine combines with exhaust gas from the boiler feed pumpturbine and flows (60 psia, 225°F) into the shell side of the recuperator where it gives up some of its heat to the propane circuit. The gas (150°F) then passes from the recuperator to the two isobutane condensers where the waste heat is rejected to the cooling water circuit. The condensed isobutane drains into the receiver. Liquid isobutane (87°F, 59 psia) from the receiver is picked up by the condensate pumps and is passed on to the boiler feed pump. The boiler feed pump then pressurizes the isobutane to heat exchanger field inlet pressure (605 psia).

Cooling water (25,000 GPM) is pumped thru the tube side of the single pass propane condenser. It then splits with each half flowing thru the tube sides of the two double pass isobutane condensers. Each condenser discharges to separate day storage and spray systems. During peak load periods, when the air wet bulb temperature is the highest, the cooling water flows directly into the day storage ponds. This allows the plant to operate with the least amount of parasitic power requirements since none of the spray pumps are operated during this period. During this nominal 8-hour period, the water level in the storage ponds will rise 4 to 5 feet. At the end of this time and when the atmospheric cooling conditions are the most favorable, the condenser discharge flow is directed to the inlet of the spray pumps. At the same time, water is transferred via sprays from the day storage ponds. The sprays are of the jet spray type which utilize a gravity fall to provide controlled stream breakup and drop size. The pressure at the inlet of the (6) spray headers can be adjusted to minimize drift and maximize cooling. The water coming off the condensers can also be dumped directly onto the cooling streams. The collected water drains into the deep pond below the pond thermal insulation layer.

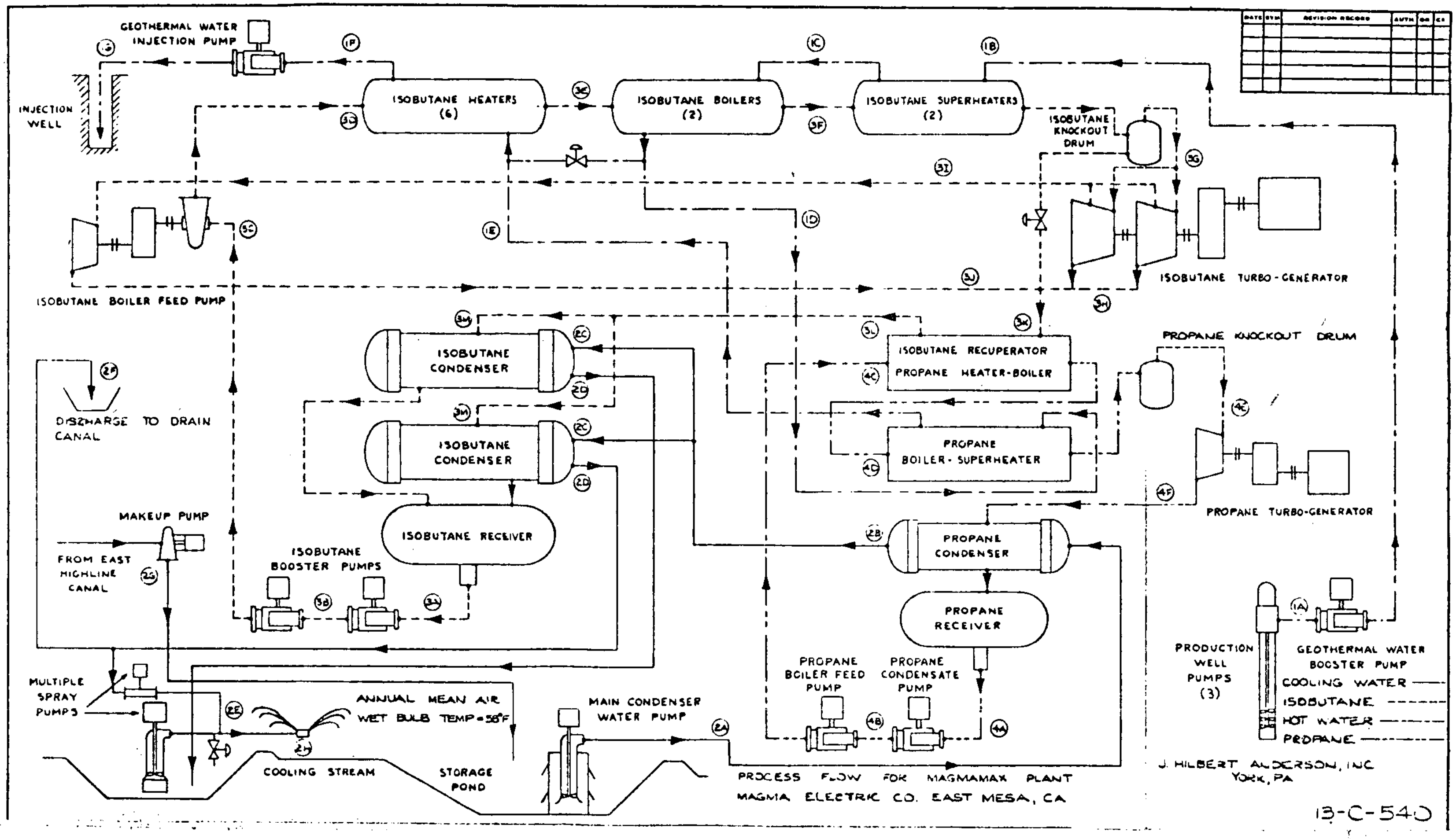


Figure 1. Process Flow Diagram

Propane and isobutane systems are very similar in operation. Liquid propane (131 psia, 73°F) is heated, vaporized, and superheated in the recuperator and one relatively small counterflow heat exchanger. Propane gas enters the turbine at 460 psia, 205°F and exhausts at 131 psia, 106°F.

B. Operational & Safety Features - The following is a partial listing of the operational and safety features that have been incorporated into the plant:

. Centralized Control: All major equipment and most process controls can be manually operated from a single control room. In addition, the majority of controls can be placed in the automatic mode once system operation has stabilized.

. Performance Indication: The facility incorporates a comprehensive process and equipment instrumentation/alarm system with indication in the control room.

. Flash Protection: Strategically placed pumps and appropriate valving maintain brine pressure at a level high enough to prevent flashing in the heat exchanger field or connected piping.

. Injection Pressure Control: Centrifugal pumps, arranged in series, provide the flexibility needed to cope with varying injection well pressures.

. Water Treatment: Make-up water is added and a measured amount is blown-down to maintain salinity at an acceptable level. Inhibitor, acid, and chlorination feed systems are provided.

. Fire Protection Systems: Fixed dry chemical, AFFF foam, water deluge, halon, and CO_2 systems installed where applicable, with U.V., thermostatic, or cross-zoned ionization detection; automatic or manual actuation. Receiver isolation valve system with associated interlocks. Portable and remote fixed extinguishing and gas detection equipment strategically located. Seal leak alarm system installed on hydrocarbon pumps and turbines. Seal blowout prevention system installed on turbines.

. Laboratory Facility: On site chemical laboratory, available for brine, gas, and cooling water analysis.

C. Predicted Performance - For 3220 gpm of 360°F brine and a yearly average cooling water temperature of 62°F, the anticipated net plant output---taking into consideration all parasitic losses associated with the facility including all brine circuit pump power---is 9.6 MW during peak demand periods and 8.8 MW net during off peak periods. Of this, the propane system contributes approximately 14%.

The estimated brine consumption rate is 131 lbs/net Kwh without any well pumping requirements as part of the plant's parasitic losses.

VI. Operating Experience To Date As described heretofore, the East Mesa plant has many new design features and principles of operation. Therefore, it should be expected that we would have certain operating problems during the startup period. As a matter of fact, many of the innovations that were used have been suggested as being too radical to put into any first plant. However, it should be remembered that most of these innovations were highly important in enabling us to build a plant which has the potential for high efficiency of energy conversion and therefore, low plant and power production costs.

Our discussion of operating problems can be divided into the four different circuits involved in the plant; namely the brine circuit, the isobutane circuit, the propane circuit, and the cooling system.

A. Brine Circuit - It was recognized very early from previous test experiences in Nevada that we very probably would have problems with calcite deposits on the walls of pipes if carbon dioxide was released or the brine was allowed to flash into steam during any part of the process of circulation. For this reason a brine booster pump was placed between the well pump discharges and the heat exchanger field inlet so as to maintain high pressure thru the entire system. During initial operation of the brine circuit we did in fact at times release gas and this produced the expected result of calcite deposition on pipe walls, valve seats, and pump casings. This problem has been eliminated by establishing operating procedures and determining control settings which keep system pressures at all times above gas release pressures, which is somewhat higher than the flash pressure of the brine.

Initially, one booster pump was installed between the wells and the plant to provide the proper heat exchanger brine pressure. In addition, three inline booster pumps were installed down-stream from the heat exchangers for reinjection purposes. All of the pumps and their sealing systems were designed for flow-thru whether operating or idling. After some initial problems with dirt in the mechanical seals, this arrangement has performed very satisfactorily.

In our initial plan, heat exchanger field warm-up was to be accomplished by running most of the brine in a bypass circuit around the plant and bleeding a small amount of hot brine to the exchangers to warm them up gradually to keep rapid temperature changes from occurring. This procedure proved to be rather tricky and some interesting stratification problems were encountered. Warming up the exchangers in this manner produced thermal stresses which were undesirable. We corrected this problem by installing a recirculation system whereby a high flow could be maintained thru the heat exchangers during the warmup process. This has made the procedure more easily controlled enabling the exchanger field to be warmed up at a very moderate rate from cold start conditions under full control of the operators. During the design phase for the brine handling system, we did not know exactly what to expect for required injection pressures. Some very short term, cold fluid injection tests had been performed, and during plant constuction, some additional full-temperature fluid injection testing was performed. Based on the data gathered during these tests, injection pumps were selected. As plant testing progresses, and injection temperatures decrease, the required injection pressures appear to be lower than would be predicted based only on the greater injection density. There is some speculation that this is due to shrinkage of the sands in the zones where brine is reinjected. This has allowed us to remove one of the injection pumps that we initially thought might be required.

B. Isobutane Circuit - Since the use of isobutane as a power fluid in this type and size plant is something new, we naturally could expect some initial problems in operation. During the startup and testing phases of this loop the majority of our problems have been equipment problems, many of them related to dirt in the system. The equipment performance has been fairly satisfactory and we are pleased with the general behavior of the power fluid as it is handled throughout the cycle. We do not yet know whether the thermodynamic performance is exactly as predicted, and we will need some steady state operation at various power levels to provide the necessary data to clearly establish this. However, the general indications are that the performance will be as expected.

During the initial stages of isobutane system flushing and cleanout the plant experienced some severe seismic activity during the October 16, 1979 earthquake that struck the Imperial Valley. While it appeared superficially that we had sustained practically no damage, when we began initial operations we found that we had a number of internal leaks at the heat exchanger tube sheets, allowing a fluid interchange between the brine and isobutane systems. An evaluation of the pattern and severity of these leaks provided the conclusion that piping movements during the quake had subjected one end of the heat exchangers to extremely high levels of moment loading, and the tube joints had broken loose at that time. After the initial shock, the joints were still able to contain pressure but they had moved to the point of having marginal mechanical strength. When we first put the system into operation, the thermal stresses shifted the tubes even more, causing excessive cross leakage which contributed to some problems that we had at that time with the isobutane turbines. These tube leaks were eliminated by welding the tubes into the tube sheets. The thin-wall tubes in the brine exchangers are likely to warm up much faster than the exchanger shell due to their difference in mass and surface area. To minimize the stresses caused by this differential expansion, sliding tube sheets were used. These sliding tube sheets presented considerable problems because of dirt left in the isobutane circuit. This dirt consisted of sand, welding beads, and shot blast material left in by the contractor during construction. The dirt caused scoring of the surfaces on the sliding tube sheet, and this caused leakage between the sealing rings at the sliding joint. This problem has now been corrected by remachining of the surfaces and installing a somewhat different seal ring configuration. The seal lubrication system arrangement has also been improved so as to insure positive lubrication at the sliding surfaces and more positive sealing between the isobutane and the brine. Early observation of the brine side of the heat exchangers indicated that we were experiencing some corrosion of the carbon steel tubes. This is attributed to the fact that after initial operation, air was allowed to contact the brine side of the tubes. Our experiences reinforce the fact that it is extremely important to protect these tubes from atmospheric air and from oxygen dissolved in any water used to fill the brine side during periods of off-line maintenance. Subsequent monitoring of on-line corrosion rates seem to indicate that carbon steel will be a satisfactory tube material for this application if proper procedures for system protection are followed.

With the exception of the leak problems, the heat exchangers have operated very well, and appear to be performing better than design predictions. We had some initial concerns about the possibility of liquid segregating in the bottom of the exchanger bundle, since the liquid was boiling inside the tubes. A typical problem in refrigerant evaporators with boiling occurring inside the tubes is that of distribution of the liquid throughout the bundle. Calculations had been made which indicated that this should not be a serious problem with isobutane under the boiling conditions encountered here, and these appear to have been proved correct. It is too early to tell whether the heat transfer coefficients are exactly as predicted, but all indications are that the heat exchangers are performing satisfactorily.

Mechanical operation of the two isobutane turbines has been generally satisfactory, with the main power turbine taking the brunt of system imposed problems.

During initial operation, welding beads, shot blast material, and sand in the system caused considerable wear on the turbine inlet nozzles. This can be expected in a radial-flow type of turbine, where solid particles in the inlet stream are thrown back into the nozzles by the rotating elements. After a considerable period of recirculation with good filtering in the isobutane circuit the problem of dirt seems to have been satisfactorily conquered. Once the isobutane system is maintained in a clean state we have no reason to believe that there will be further deterioration of the turbine nozzles.

After the initial period of operation, we had a temporary debris screen in the isobutane gas circuit fail due to high velocity vortex action in the Knockout Drum. Parts of the screen were broken and passed thru the turbine, causing unbalance and requiring dismantling and rebalancing of the turbine rotors. At the same time we had to rebuild some of the turbine nozzles due to damage from this debris. It was very gratifying to see that the rugged turbine rotor construction withstood the passage of fairly heavy particles of steel screen.

Another problem that occurred during the period of increasing load on the turbine was high pressure intake pipe vibration. This was caused by poor flow orientation, and has since been corrected so that now the pipe and valve vibration has disappeared.

One of the problems in designing a high pressure organic fluid turbine of this type is the problem of thrust balancing in the rotor. This was carefully monitored during initial operation, and we did find that thrust at high loads on the thrust bearing became higher than was desirable. Careful monitoring of the thrust balance system indicated that there was excessive leakage in one of the balance pistons. This was corrected by installing a new design balance piston seal which reduced this leakage to an acceptable value, and the thrust levels since that time have been very satisfactory. By careful monitoring we were able to avoid any problems with thrust bearing failures.

Main turbine and boiler feed pump turbine efficiencies and flow coefficients are being compared with original design values and with the exception of a lower flow coefficient than expected on the main turbine, appear to be satisfactory. We are presently taking steps to increase the flow coefficient for the main turbine to its original design value.

The mechanical seals on both isobutane turbines have operated very satisfactorily, and have provided absolute seal-off during standby periods.

The turbine drive couplings have operated very satisfactorily with no vibration problems and no thrust problems, which so commonly occur when gear-type couplings are used on high speed drives subject to high thermal expansion. These couplings are also particularly convenient for disassembly of the seals, bearings, or turbine rotors.

During early performance trials we had the usual problems with control and safety wiring in the electrical system. These problems were caused primarily either by defective relays or by mistakes in wiring up the system. There were also some initial generator vibration problems which had to be corrected.

C. Propane System - The propane system has not yet been put into service. Since the propane system is very similar in principle to the isobutane system, we have every reason to think that operation should be satisfactory. The principle unknown at this time is related to the recuperator performance, since this is a new design incorporating a combination of liquid heating and boiling in the same flow passages. The recuperator has the function of cooling down the superheated exhaust gas from the main isobutane turbine, thereby reducing the cooling load in the isobutane condensers. This is designed to increase the power output from the plant, and at the same time increase cycle efficiency, thereby reducing the plant heat rejection load.

D. Cooling System - The cooling system has in general performed as expected, although a complete performance evaluation cannot be made until the plant is operating at full load design conditions. The principle problems with the cooling system has been with the ponds used to store both the warm and cold water for the thermal peaking system. The very loose character of the East Mesa soil made it difficult to excavate and construct the ponds with the assurance that the pond banks would maintain their integrity. The ponds were originally designed to be lined with soil cement, but because of a cement shortage, plastic liners were used.

At first there were some wind and wave problems causing pulsation of the plastic on the banks. This was corrected by using gunite to hold down the material along the banks where they were subject to wind and wave forces. The wave action was greatly reduced by installing wave breakers across the ponds. Some serious problems have occurred because of failure of the adhesive joints in the plastic. This was due, apparently, to a combination of faulty adhesive, high temperature, moisture, and fatiguing of seams. Newer adhesives are now being used, but we do not know whether these will hold up over a long period of time. It is probable that the overlap joints in the plastic on the spray cooling surface were made too narrow and should have been made with double overlaps. In some areas we have covered the spray area with cement in order to hold the plastic down tightly and eliminate some of these probable modes of failure.

Originally the specified depth for the deep storage pond was approximately 30 feet. This was to insure adequate separation of the warm and cold layers of water so as to be sure to get proper cold water storage. Because of the soil structure and the high water table we had to compromise and construct a much shallower, larger surface area pond. Preliminary indications are that adequate thermal separation does exist. On one occasion during operation we have measured as much as 14°F temperature difference between the cold water at the bottom and warmer surface water. It appears that the principle of storing cold water at the bottom of the pond will work quite satisfactorily, although this must be determined by long time operation at full load under the various climatic conditions. The unique jet spray cooling system appears to be working quite satisfactorily. There does not appear to be excessive driftloss and the principle of allowing airflow through the jet sprays seems to be working as planned. On the whole, we believe the performance of the jet spray cooling system and storage systems appears to be performing as planned, although full load operation over a long time has not yet been analyzed. It is probable that this cooling system has been designed somewhat conservatively, and future systems of this type can be designed at considerable reduction in size and cost.

E. Preliminary Conclusions on Plant Operation - Although the plant has not yet been operated in full brine flow, full turbine load, or with the propane system operating, we feel very encouraged by the general operation of the plant. The operators have found the plant very easy to operate, and the principles of operation of the system appear to be sound. We have every reason to believe that future plants of this kind can be designed at a considerably reduced cost, and the cycle can be improved by further optimization and utilization of the design principles developed in this plant.

VII. Protection of the Environment The Magmamax Power Process system has several inherent features associated with it that are advantages from an environmental standpoint. The brine system and the power systems are completely closed, with no emissions to the atmosphere. The cooling water system is the only one that has emissions and those are limited to water vapor being put into the air. In our considerations of location of the project and the construction of the cooling ponds one of the criteria that we utilized was that the project site would be situated such that there would be no necessity for importing fill or removing fill from the site; therefore one of the reasons for the configuration of the site is to balance out the cut-and-fill. Discussions were carried out with regulatory personnel on the esthetics of the plant and muted-type colors that would blend in with the desert landscape were selected for the various piping systems. Several requirements for monitoring air, water and land and ecological characteristics in the area were established in the operating permit associated with the plant.

VII. Finance and Economics Magma chose to utilize their available funds to finance the construction of the plant. Being a research and development plant in nature it would have been most difficult to obtain project financing, looking to the revenue of the plant solely as collateral for pay back of any financing associated with it. The project did cost considerably more than was anticipated when initiating the project, and short term bank loans were required during the construction to maintain an adequate cash flow in conjunction with the revenue available to Magma from the Geyser's to complete the project. The total cost of the plant was slightly under fifteen million with the following breakdown of the various major categories of the plant:

Category	Total Cost
1. Land Improvements	$ 531,700
2. Building	319,500
3. Cooling System	3,472,700
4. Power Equipment	1,017,400
5. Isobutane System	2,382,800
6. Propane System	1,050,000
7. Brine System	2,026,100
8. General Support System	1,565,100
9. Engineering	948,000
10. Overhead and A & G	1,413,900
11. Total	$14,727,200

There are two aspects of the plant which were costly in nature and have yet to be demonstrated as to their cost effectiveness. One is the cooling system and the other is the propane system. The initial studies associated with the cooling system, which incorporates large amounts of water storage to allow cooling to be done at off-peak times when wet bulb temperatures are lower, indicated that there would be a payoff both in capacity and energy. The addition of the propane system appears to be appropriate in that the additional capacity available, on an incremental cost basis, is lower than the overall unit cost of the plant. The prime motivation for installing the propane system is to gain some operating experience with that as a power fluid and to provide operating data on a bottoming cycle using the exhaust heat in the isobutane. The isobutane provides approximately 75% of the heat input into the propane and is so doing cuts down on the rejected heat required in the condensing system of the isobutane. The propane system will also demonstrate the technical feasibility of using geothermal brines in the very low temperature range. The design temperature of the propane vapor into the turbine is 205°F.

It will take more time before any reasonable establishment of operating and maintenance costs for the facility can be determined.

Since the East Mesa plant was a compromise design, and did not take advantage of the best optimization of the system it is natural to expect that a newer design would improve performance.

Latest developments in heat exchanger design indicate that we can get considerably better performance out of the true-counterflow heat exchangers than the existing design in the Magma East Mesa Plant. Because of improved performance capability and better arrangement of the heat exchanger systems, we can confidently expect to reduce the plant discharge temperature from 180°F to 140°F, which will provide considerably more heat available for conversion to power. Therefore, the brine consumption can be reduced simply by utilizing more Btu per lb., assuming that reservoir conditions will allow the lower reinjection temperatures.

In addition to improved heat transfer and plant design optimization we also can expect that radically new turbine designs can achieve efficiencies of 92 to 96%. This makes an appreciable difference in the plant efficiency and output.

The predicted brine consumption per Kwh for the plant with a 360°F inlet on a gross, net without power for well pumping and net with power for well pumping basis is 115, 131, and 150 pounds per Kwh, respectively. With a 325°F inlet the quantities would be 152, 175 and 210, respectively. These quantities are significantly less than those associated with proposed two-stage steam flash plants with the same brine temperature. Improvements in the binary system design as discussed above have the potential for reducing the above brine consumption rates in excess of 30%. Therefore, greater improvements in the economics and the all-important conservation of the resource can be expected.

Our experience at the East Mesa plant has confirmed that all of the advantages of the dual-fluid vapor turbine cycle described in the introductory paper[1] presented in 1972 do indeed exist. The development of the dual-fluid cycle, the improvement in heat exchanger efficiency, better cooling systems, and higher efficiency turbines make the cycle look more viable than ever for economic, efficient geothermal power generation.

Following are the advantages listed in the 1972 paper which apply even more strongly now:

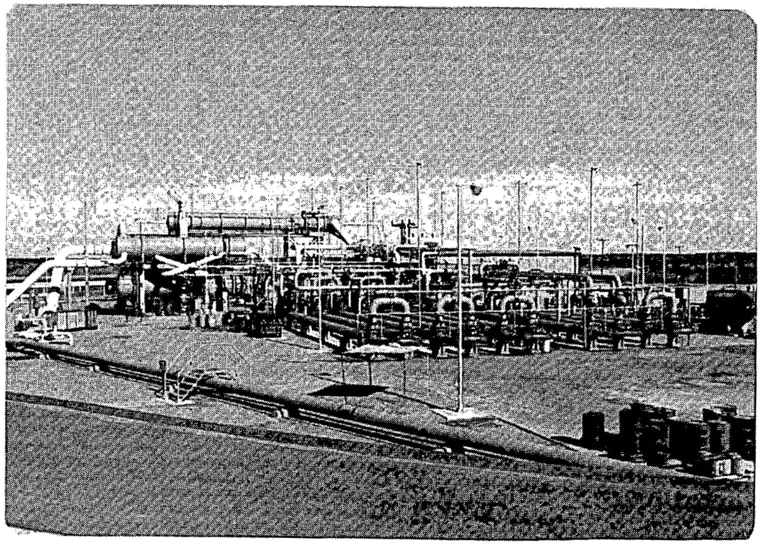
1. Pumping water to the surface at pressures above saturation insures water reaching surface at nearly full maximum well temperature, whereas lifting water by steam causes large temperature decreases.
2. Keeping water at full pressure retains dissolved gases in water, so that they can be returned to the ground without danger of atmospheric pollution.
3. If steam and dissolved gases come out of the water, the chemical composition is changed, often causing precipitation of solids out of solution and plugging of wells.
4. Keeping water at high pressure throughout heat exchangers helps to minimize heat exchanger tube stresses. The possibility of stress corrosion, which is often the most vital factor in causing failure of high temperature hot water heat exchangers, is thereby reduced.
5. Vapor turbines can generally be more efficient than steam turbines, because they usually have fewer stages and the volume change through the turbine is not as great.
6. Wheel speed on vapor turbines is usually lower than that of steam turbines. Therefore, design problems are simpler, and blade stresses are much less severe.
7. Vapor turbine cycles can be relatively quiet. Flashing steam cycles require costly noise abatement measures.
8. Isobutane turbines operate above atmospheric pressure throughout the cycle. The possibility of getting air and oxygen into the turbine to cause corrosion or explosive mixtures is eliminated. Air entering the system under vacuum is a major cause of corrosion in steam systems.
9. Isobutane and some other fluids are relatively simple and low in cost.
10. Isobutane turbines are much smaller and, therefore, lower in cost than steam turbines of the same power output.
11. Isobutane expands through the turbine completely in the dry state. This eliminates the problem of blade erosion by water droplets, so common in steam turbines.
12. Isobutane is compatible with oil. This makes it possible to use internal bearings in turbine, which make a much more rugged and lower cost design turbine possible. They also permit using a single shaft seal at the coupling end

of the turbine, completely eliminating all of the long, complicated, leaking shaft seals required on a steam turbine.

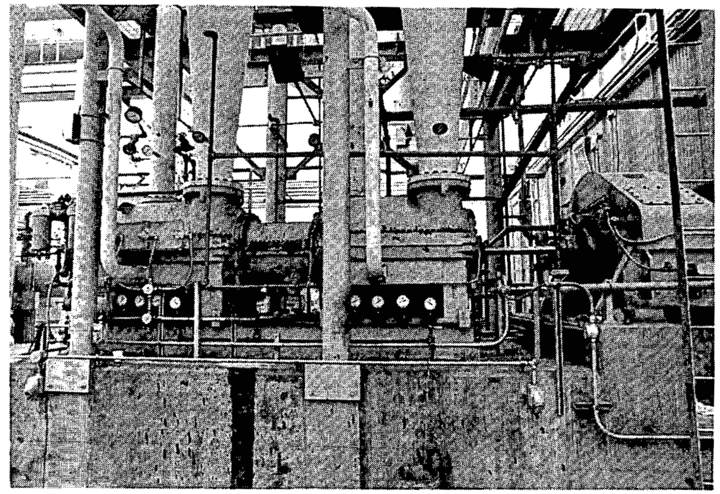
13. Isobutane is non-corrosive and there should be no need for expensive stainless steels in any part of the turbine, such as are often required in the flashed steam cycle.
14. Isobutane liquid has a lower density and lower latent heat than steam. Therefore, cavitation damage should not occur in boiler feed pump.
15. Isobutane boiler feed pump can be made from cheaper materials than water feed pump, because corrosion problems are minimal.
16. Isobutane turbine has much lower rotating inertia than a steam turbine of the same power. This virtually eliminates the short circuit torque problem at the drive couplings.
17. Isobutane turbines can be designed to utilize lower condensing temperatures, thereby improving cycle efficiencies and reducing water rate below that of steam turbines.
18. Isobutane turbines do not require gas removal equipment. Steam turbines can require substantial gas removal equipment.
19. With no air or incondensable gas in condensers, isobutane condensers can be 100% effective all the time. With steam condensers, gas in system reduces condenser efficiency by increasing condensing pressure.
20. The isobutane cycle permits effective use of heat from well water down to quite low temperatures. Water can be discharged from a plant at temperatures as low as 120°F. In comparison, steam cycles could rarely be economic at water discharge temperatures below 212°F. This helps isobutane cycle to be more efficient than steam cycle.

Reference

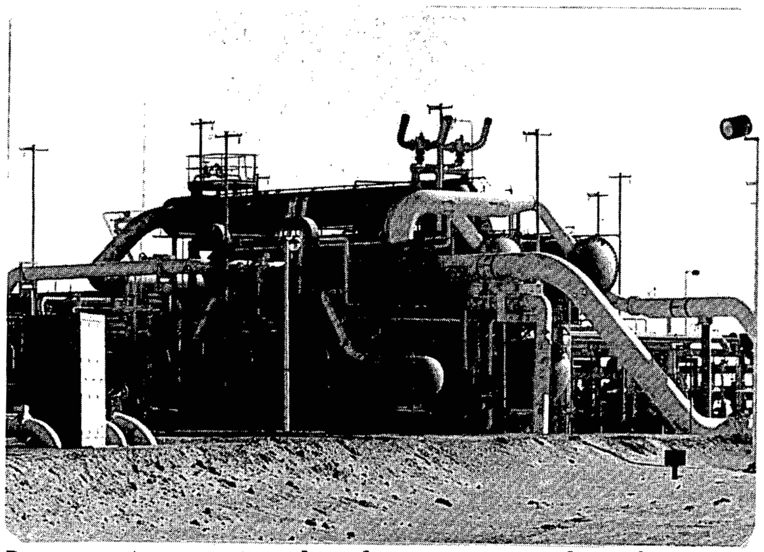
1. J. Hilbert Anderson, "The Vapor-Turbine Cycle for Geothermal Power Generation", Geothermal Energy, Kruger and Otte, Stanford University Press, 1973.



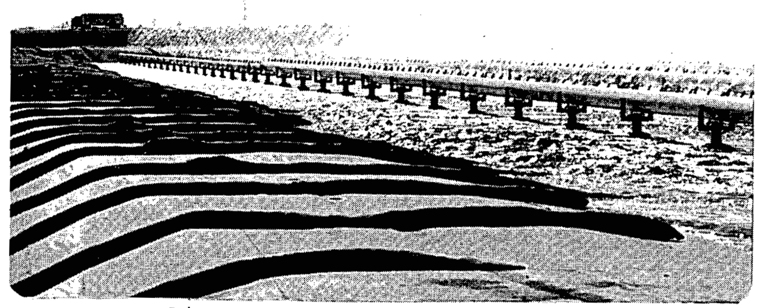
Brine/Isobutane exchangers in the foreground and recuperator, condensors and receivers in background.



Isobutane tandem turbines and gear box which is coupled to main 10.5 megawatt generator.



Recuperator on top level, propane and Isobutane condensors on second level and receivers on lower level.



Cooling water jet sprays in operation.

Dup

5MW RAFT RIVER FACILITY EXPERIENCE

DOE-Idaho Operations Contract No. DE-AC07-76ID01570

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Introduction The Raft River geothermal plant is a small binary cycle conversion system which uses isobutane as the working fluid. This plant uses a staged boiler concept to achieve better performance than could be obtained by a single boiler. The plant was designed to operate with a geothermal water inlet temperature of 143°C (290°F) and produce a nominal generator output of 5MW. The plant is supported by a supply and injection system consisting of three supply wells (about 1524m or 5000 ft deep) and two injection wells (about 1158m or 3800 ft deep).

The plant is nearing the end of the construction phase. System tests will be conducted throughout the Summer; plant startup is scheduled for the Fall (1980). A complete description of the plant is contained in Reference 1.

This paper will briefly discuss our experience in several important areas: environmental, supply and injection system, and power plant.

Environmental Program An environmental program has been underway at Raft River for several years. Background data is being obtained from a subsidence grid, three seismic stations, and seven monitor wells and three USGS wells. When the plant is in operation, there will also be four air quality monitoring stations.

Air quality, subsidence, and seismicity have not been major concerns at Raft River. The geothermal water quality is quite good. Boran, Arsenic, Mercury and Hydrogen Sulfide are not a problem. Flourides and salt are high. The poorest quality occurs in well RRGE-3 where the total dissolved solids is about 4300 mg/l. The two major concerns are impacts on sensitive wildlife in the region and impacts on ground water.

The primary wildlife concern is for the protection of the Ferrugenous Hawk nesting grounds which are located throughout the area, although Golden Eagle and Swainsons Hawk is the primary concern because it will desert the nest when disturbed, leaving eggs or young. Buffer zones of about one mile in radius were established around the nests. A monitoring program proved these buffer zones were adequate to protect the birds.

The Raft River area has several water bearing regions of varying salinity. The geothermal aquifer has no cap rock to clearly separate it from upper aquifers. Throughout the region good communications exist between all elevations. The geothermal water will be injected into two wells.

The subsurface water in the injection region increases in salinity with depth reaching about 6000 ppm of total desalved solids at an elevation of 600m to 900m (2000 ft to 3000 ft). Because of the very high communication between various levels there is concern that injection (of the cleaner geothermal water) will displace the salty water upward into the ground water aquifer. The region is presently classified as a closed water basin and any degradation of the ground water is of special concern. We are currently investigating shallow injection through several injection wells to determine if less impact on the ground water will occur; however, there are no immediate plans to change the injection mode for the pilot plant. Monitor wells and chemistry measurements will be used to determine if the potential intrusion of salt water occurs and its severity.

Supply and Injection System The two areas which have caused the greatest problems to date are the use of cement-asbestos piping and our rather disappointing experience with supply pumps. Each of these areas are discussed below.

1. Cement-Asbestos Pipe for Geothermal Transmission Piping The supply and injection system piping is a combination of steel and cement-asbestos pipe. Transitions to steel are used where branches connect or where the pipe must be run above ground. This pipe was initially installed because of the lower purchase and installation cost compared with steel (about 55%). The pressure drop is also significantly less (40%) thereby permitting use of smaller pipe. Initial installations were made in 1975. The pipe worked reasonably well when handling minor flows to ponds through single runs; however, when considered as part of a multi-well system, it greatly complicates design and operation because of restrictions due to pressure limits (150 psi) and thermal shocks.

These concerns exist primarily during startup, shutdown, and plant upsets.

To date about 32 failures have occurred which can be classified as pipe ruptures (40%) and coupling/gasket leaks (60%). The ruptures were thought to be the result of thermal shock, water hammer, defective pipe and unknown causes. Leaks at the joints are caused by broken or rolled gaskets and shifting collars, some of which may be due to thermal ratcheting. When breaks occur, stones and dirt get washed into the pipe causing filters to clog and sometimes high pressure drops due to large rocks getting into the system and lodged at restrictions. Operations to date have been rather severe because the system has not been maintained on the line for a long time - a lot of startups and shutdowns, and the true causes of ruptures are difficult to establish. Although numerous failures have occurred, extended periods of operation without incident have also existed.

The use of cement-asbestos pipe started as a cost saving experiment. Longer operation as part of the supply and injection system for the power plant is needed so that true maintenance costs and time out of service can be balanced against the initial cost savings. In a larger plant with more wells the consequence of a failure may not be as severe.

2. Supply Well Pumps Over the past five years both line shaft and submersible pumps have been used in the Raft River wells. The line shaft pump operated for about 1100 hours without incident before removal but requires complete rebuilding. One type of submersible pump with a relatively small motor and installed at a shallow depth (approximately 240m) was also used extensively and without significant problems. However, we are currently having a great deal of problems with early failure of the large motors on our present submersible pumps which are set at 600m (Centrilift) while a smaller unit of the same design operated for over a month before failure. A chronology of our pump experience is given in Table 1.

Apparently submersible pumps are designed to be installed and run to failure. This type of operation is not consistent with the needs of a power plant during the startup/shakedown period. The submersible pumps also have minimum flow requirements that may be between 60-70% of the rated flow. This flow requirement causes operational problems in bringing a well on line when observing pressure limitations of our cement-asbestos pipe. It is clear from our experience that much more development is necessary before a truly suitable pump is available for geothermal applications.

TABLE 1 CHRONOLOGY OF PUMP EXPERIENCE AT RAFT RIVER

Installation Date/Well	Type	Manufacturers	Set Depth m (ft)	Hp	Installed Duration - Mo.	Time-Hrs.	Comments
11/75-1	Sub.	Reda	189 (620)	300	6	112	No failure - large for well
5/77-3	Sub.	Reda	236 (773)	320	12	1359	Cable shorted on grating
4/78-2	Shaft	Peerless	244 (802)	250	4	1060	No failure - tail bearing worn
3/79-5	Sub.	Reda	305 (1000)	320	8	568	No failure - bad bearings
9/79-1	Sub.	Centrilift	616 (2021)	650	4	114	Shorted - leaking seals
9/79-2	Sub.	Centrilift	567 (1860)	500	5	0	Short on electrical test
9/79-3	Sub.	Centrilift	338 (1110)	250	5	0	No failure
12/79-5	Sub.	Reda	335 (1098)	320	4	85	Failed - short - pumping sand
4/80-1	Sub.	Centrilift	616 (2021)	650	1/4	8	Failed - motor
4/80-3	Sub.	Centrilift	318 (1042)	250	2	800	Failed - short
4/80-2	Sub.	Centrilift	574 (1884)	500	1/4	0.18	Failed - short
5/80-2	Sub.	Centrilift	574 (1884)	500	---	0.23	Failed - short

Power Plant Water Treatment Geothermal water (from the plant discharge) is used for cooling tower makeup because the Raft River valley is a closed water basin. The water is pretreated to remove silica and reduce hardness so that scaling will not occur in the cooling system. The fluid is then treated to inhibit corrosion of the carbon steel condenser tubing. The problem of pretreating the geothermal water and inhibiting corrosion of the carbon steel tubing was not considered to be a difficult problem, in fact it was considered well within the state-of-the-art. Tests proved this opinion wrong.

The original water treatment system was designed to use dolomitic lime which furnishes the magnesium necessary for silica reduction and the calcium oxide which when hydrated reacts with the calcium bicarbonate to cause calcite precipitation. The design was based upon the information available at that time for silica removal (up to approximately 80 ppm). Testing has shown that extrapolation to the 160-200 ppm of silica existing in the geothermal water isn't possible. Many tests have been performed to establish a silica reduction and softening program that is compatible with our installed equipment. The overall program is complicated by severe pitting corrosion of carbon steel (the condenser tubes are carbon steel) which in our initial tests persisted even when extremely high levels of chromate, far in excess of design, were added to the water. In addition, normal dispersant dosages are inadequate to prevent scaling, apparently due to the many other chemical species present in the geothermal water.

A test program is currently underway to establish a condenser cleaning and prefilming procedure and a inhibitor schedule. The tentative conclusions to date are:

1. Operating cycles of concentration will be about 5 rather than 10.

2. Magnesium chloride will be used for silica reduction rather than dolomitic lime.

3. Tubes will be pretreated with a phosphate. The corrosion inhibitor will be a combination phosphate - chromate system.

4. Condenser life may be fairly short - perhaps only 3-5 years.

5. Chemical treatment costs will be extremely high - perhaps $30 to $40 per year/gpm of cooling water circulated.

Other water treatment work, not directly associated with the 5MW plant, is underway at Raft River that promises to substantially reduce these costs.

References

1. J. F. Whitbeck and R. R. Piscitella - Raft River 5MW Geothermal Plant, Proceedings of the Second Geothermal Conference and Work Shop, EPRI, WS-78-98, October 1978.

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INTRODUCTION Located in Northern California in Lake and Sonoma Counties about 90 miles north of San Francisco, Pacific Gas and Electric Company's (PGandE's) The Geysers Power Plant, which has at present fourteen units in service with a net generating capacity of 798MW, is the largest geothermal development in the world. Eight additional PGandE units now in construction, design, and planning will add 720MW of additional capacity by 1986. Figure 1 shows the location of this project and the locations of the existing and future units.

This paper discusses evolution of Geysers Unit 18 through resource and project planning, licensing, design, and what is expected during construction, and startup. While many of the experiences are unique to The Geysers units, some could be applicable to other geothermal developments. This unit is one of a series of 110MW units of standardized design which are being developed to reduce the cost and improve schedules. Construction has just commenced, and it is expected to be in commercial operation in October 1982.

RESOURCE PLANNING PGandE's long-range electrical resource program is continuously reviewed and updated in light of projected load growth and the availability and cost of alternative generating options and the resources they require. In order to minimize the cost of power production to serve varying electric demand, both peaking and base-load units are included in the resource program. Since The Geysers units currently are PGandE's least costly thermal electric resource they are operated in the base-load mode as much as possible.

Another factor in resource planning is the contractual obligations between PGandE and its steam suppliers at The Geysers, Thermogenics, Aminoil USA, and the Magma-Thermal-Union joint venture. This last group will furnish steam for Geysers Unit 18. Under our contracts, PGandE will install new generation at about 100MW per year if the steam suppliers prove up the geothermal resources required. In this phase of the Unit 18 planning, the suppliers provided resource data and PGandE's geothermal reservoir consultant confirmed the availability of steam.

Regulation also is a major consideration in resource planning. PGandE, as a regulated utility, must obtain approvals from the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the County Air Pollution Control Districts (APCD's), and other federal, state, and county planning and licensing agencies. Their regulation ranges from approval of long-range resource programs and rate of return on investment by the CEC and CPUC to environmental and reliability reviews on individual power projects. These reviews can change project lead times and costs which in turn can affect the selection of one type of generation over another.

PROJECT SITING AND LICENSING After its position in the resource program had been established and the steam reserves to support it confirmed, the siting and licensing phase of the Unit 18 project was initiated. In this phase the site was selected and the project cost and a schedule refined. Figure 2 shows the schedule for Unit 18.

Site Selection The topography of The Geysers area is characterized by northwest trending ridges and steep canyons. The ridges vary in elevation from 2,500 to 4,700 feet above sea level; the canyon floors are as low as 1,200 feet. Moreover, this area has widely varied sensitive environmental features. Site selection which must take into account the individual characteristics of each site is a dynamic process.

The Unit 18 site selection involved three phases and was done by a team of engineers, geologists, biologists, and architects who were responsible for selecting a site which is structurally, environmentally, and economically sound. In the initial phase of site selection, 18 potential power plant sites were identified after reviewing topographical and geological maps, aerial photographs, and carrying out field reconnaissance of the steam supply leasehold. Topographic and geologic features, soil characteristics, landslides, and faults were catalogued. Hydrologic features such as flooding potential, erosion, sediment transport, and the existence of groundwater, environmental impacts to water quality were identified. Aquatic and terrestrial ecology, noise, visual and air quality, and archaeological and other cultural resources within the leasehold were considered. Construction constraints such as accessibility, cut-and-fill requirements, and material disposal were noted. The steam supplier's surface and subsurface rights at the sites were confirmed. Potential transmission line routes were identified. Four months were required for this phase. After weighing these constraints, six sites warranted investigation in Phase II. In this phase a preliminary plant layout was prepared for each site which showed cut-and-fill slopes, access roads, retaining walls, and all areas of surface disturbance. These were distributed to the siting team members for more detailed reconnaissance. Evaluations of environmental and visual impacts and hydrological effects were updated in light of the more accurate information available on the extent of disturbance at the sites. Surveys by the biologists confirmed the assumptions on habitat types used in rating the sites during Phase I.

The siting team evaluated transmission line routes from the preferred sites to ensure that they are feasible from a construction standpoint and that environmental impacts can be mitigated. Near the end of Phase II geotechnical evaluations, the best apparent sites were investigated by core drilling, seismic refraction surveys, and trenching to confirm their underlying geological features. This revealed that our assumed best site required costly foundations and retaining walls and it was rejected.

Because of the extreme topographic features at The Geysers, PGandE has been unable to make precise models of dispersion patterns for air pollution by mathematical means. Therefore, during Phase II, wind tunnel model tests were conducted to evaluate air pollution impacts for those sites where a precise analysis was

FIGURE 1

MAP OF THE GEYSERS AREA

Pacific Gas and Electric Company

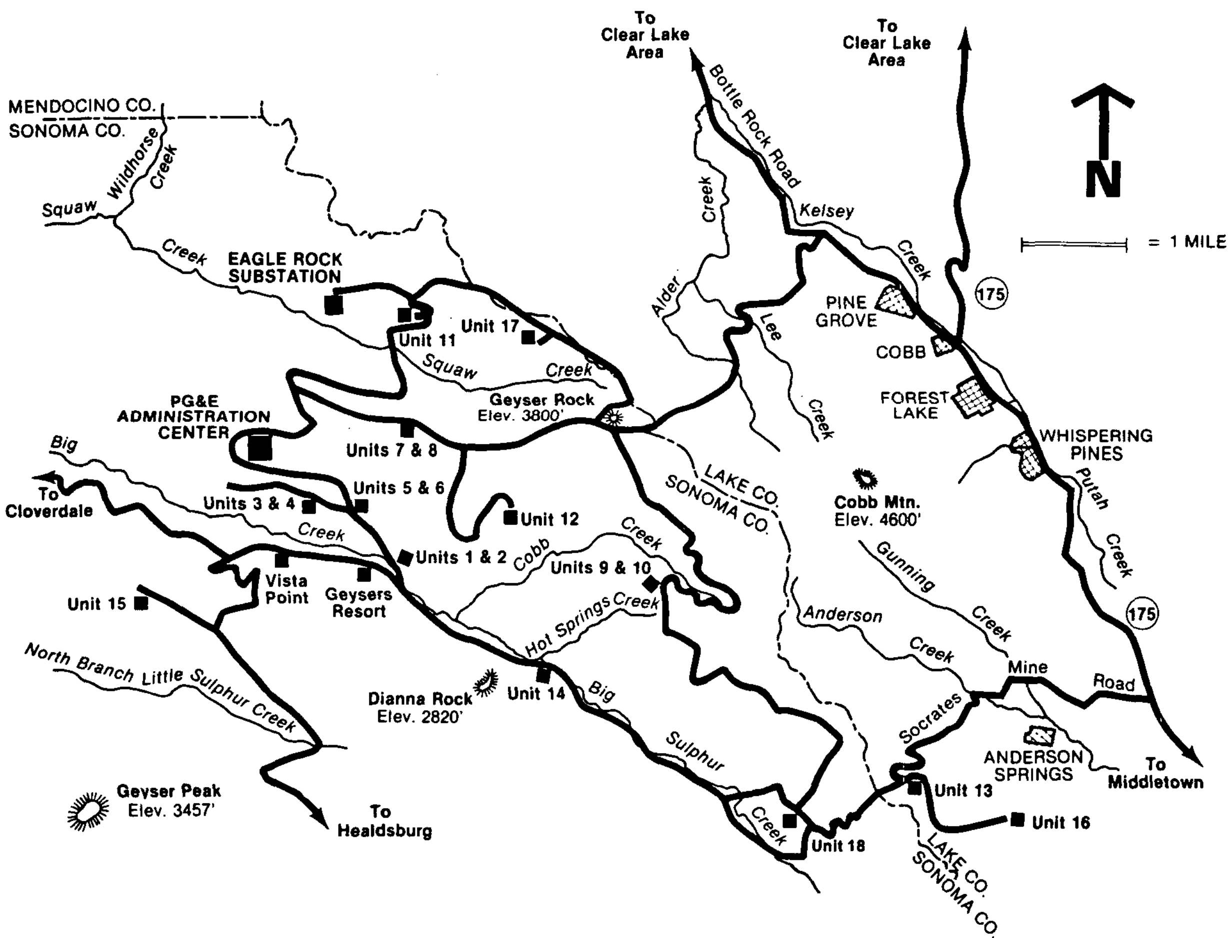
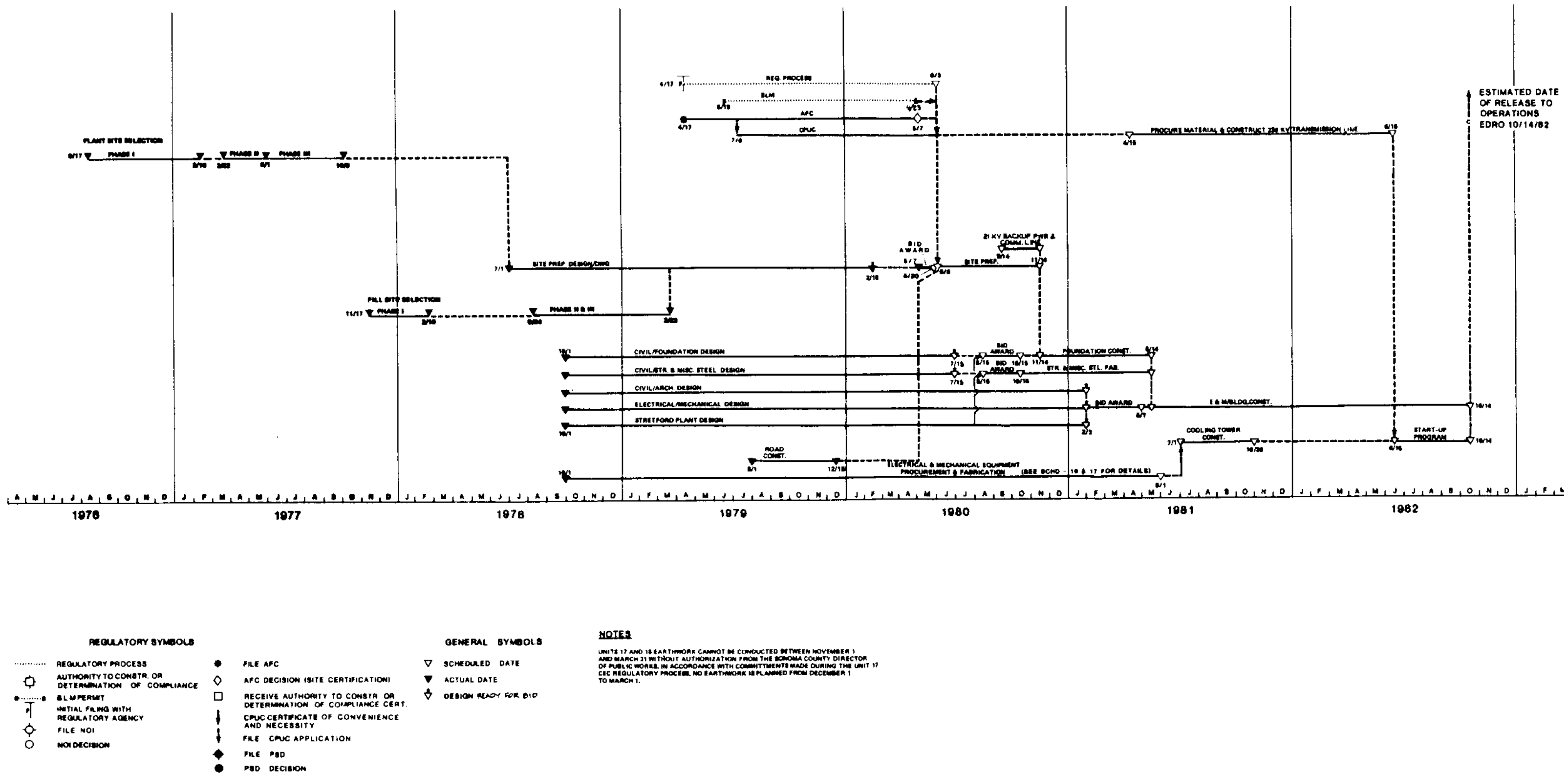


FIGURE 2

GEYSERS UNIT 18 SCHEDULE



NOTES

UNITS 17 AND 18 EARTHWORK CANNOT BE CONDUCTED BETWEEN NOVEMBER 1 AND MARCH 31 WITHOUT AUTHORIZATION FROM THE SONOMA COUNTY DIRECTOR OF PUBLIC WORKS. IN ACCORDANCE WITH COMMITTMENTS MADE DURING THE UNIT 17 CEC REGULATORY PROCESS, NO EARTHWORK IS PLANNED FROM DECEMBER 1 TO MARCH 1.

needed. This method has been found to give results similar to tracer studies at lower cost.

At the conclusion of these 10-month studies, one power plant site was selected for the Phase III study. In Phase III, more detailed geotechnical investigations were performed on the site to determine specific foundation design requirements and detailed environmental mitigation plans were prepared. Phase III required four months. Up to this point the investigation had been based on balanced cut-and-fill site designs. However, at this point there remained a diversity of opinion among the team members on the best way to dispose of material to be excavated from the plant site. Engineering and construction representatives favored on-site disposal while biologists favored disposal of this material in an old open-pit mercury mine nearby to avoid impacting an environmentally sensitive area adjacent to the plant site. To balance these views required essentially another 15-month, 3-phase study of both on-and off-site disposal alternatives. In the end it was determined that use of a combination of on-and off-site disposal was both environmentally and economically acceptable.

Geothermal Licensing Processes Before Unit 18 construction could commence, several regulatory documents needed approval. Preparation of these documents began soon after the start of site selection. Since the passage of the Warren-Alquist Act, projects with a net generation capacity of 50,000 kilowatts or more are under the jurisdiction of the CEC's process which requires approval of two documents: the Notice of Intention (NOI) and/or the Application for Certification (AFC). These documents describe the proposed project, its purpose, need, design, construction, operation, and assess the physical, economic, and sociological impacts of geothermal resource utilization at that site. Also included in these is information sufficient to satisfy an Authority to Construct (A/C) with the local Air Pollution Control District, and Use, Grading, Building, and Sanitation Permits with the appropriate local county agencies.

Because the CEC has designated geothermal energy a preferred resource, it has initiated an expedited license procedure that is shorter than other energy sources. A nine-month NOI review process and a nine-month AFC review process are required for a geothermal unit for which a steam supply is not proven or an expedited twelve-month AFC review process can be followed if the proposed leasehold has been proven to be capable of providing steam in commercial quantities. Since the steam supply for Unit 18 had been proven, it followed the one-year AFC process. The AFC was approved on May 7, 1980.

In addition to CEC certification, a Certificate of Public Convenience and Necessity (CPCN) must be granted by the California Public Utilities Commission (CPUC) prior to the construction of a new power plant. This contains the location and a general description of the proposed generating facility and related facilities, a list of the agencies responsible for approving the plant, load and resource data, and estimated cost information, including plant and fuel costs. By regulation, the CPUC must issue its decision on these applications no later than 30 days after the CEC has issued its final decision on the AFC. The Unit 18 CPCN was issued June 3, 1980 and Power plant site preparation started June 5.

Even after the regulatory agencies have approved the plant they continue to play a key role as they closely follow the project through design, construction, and operation through a Compliance and Monitoring program prepared as part of the CEC process.

Although the Legislature, the CPUC and the CEC, have attempted to expedite geothermal power plant licensing within the confines of the Warren-Alquist Act (which established the CEC), the excessive number of reports required have made the regulatory process and post-approval requirements quite burdensome.

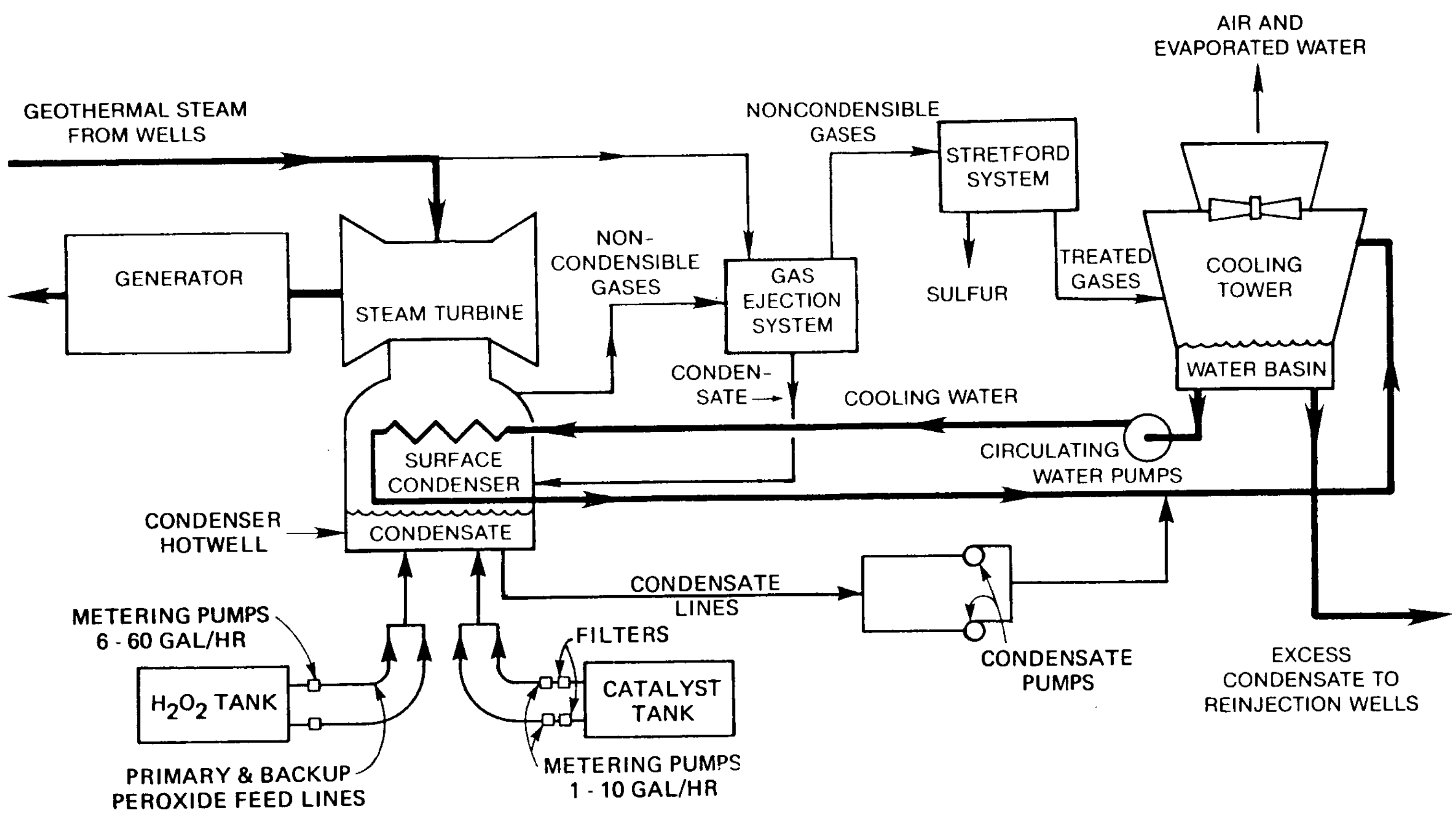
DESIGN AND EQUIPMENT PROCUREMENT Normally, the first items purchased are the turbine-generator unit and the condenser which largely determine the design of other equipment and the layout of the plant. However, Unit 18 is the second in a series of standard units so major equipment identical to that purchased for the first unit, was obtained on options. The standard units are 16, 17, 18, 20, and 21. The turbine building equipment and its arrangement and the cooling tower for these units are identical; however, the relative location of turbine buildings and cooling towers are varied to accommodate the optimum plant arrangement on individual sites. The Stretford H_2S abatement systems for these units have minor differences to accommodate the varying H_2S levels in the steam.

Figure 3 is a diagram of the power cycle.

Power Generation System The Toshiba turbine-generator units have a guaranteed gross capability of 120MW at a steam flow of about two million pounds per hour. Turbine inlet

FIGURE 3

UNIT 18 POWER CYCLE



pressure is 100 pounds per square inch gauge at a temperature of 338 degrees Fahrenheit; turbine design back pressure is 3.0 inches of mercury absolute. The turbine is a two-cylinder, four-flow design. Steam is admitted to the turbine through two main stop valves, two swing-check valves, and two butterfly control valves.

The generator is a 3,600rpm, hydrogen-cooled, three-phase, synchronous unit rated 137.8 MVA 13.8kV, 0.9 power factor, and 60 Hertz.

Condensate and Circulating Water Systems The major components of the condensate and circulating water systems are the surface condenser, condensate pumps, cooling tower, and circulating water pumps.

The surface condenser located directly beneath the turbine exhaust hoods has a design operating pressure of 3.0 inches of mercury absolute. The design cooling water flow rate is 141,000 gpm at 80^{o}F inlet temperature.

Condensate is pumped from the condenser hotwell to the cooling tower by one of two 100 percent capacity vertical, canned-type condensate pumps. Each of these pumps is rated at 4,700 gpm at 119 feet head and is driven by a 200 hp, 1,200 rpm motor.

An eleven-cell, mechanical-induced draft, crossflow cooling tower provides circulating water for Unit 18. Each cell has a 28-foot diameter, 12-bladed fan powered by a 200 hp, 1,800 rpm motor. Space for an additional cell is provided if increased capacity is indicated after operational testing. The outside tower dimensions (including the extra cell space) are approximately 384 feet long, 60 feet wide at the base, and 65 feet high. The cooling tower is covered by corrugated fiberglass panel end walls and air intake louvers. The wood structural members are clear heart redwood or pressure treated Douglas-fir. The cooling tower is designed to reduce the circulating water temperature from 105 to 80 degrees Fahrenheit at a 65 degrees Fahrenheit wet bulb temperature. The cooling tower design flow rate is 168,000 gpm and the design evaporation rate is 3,400 gpm.

Two half-capacity vertical, wet-pit circulating water pumps pump cool water from the cooling tower basin, through the condenser tubes, and return it to the top of the cooling tower. Each pump is rated at 84,000 gpm at 105 feet head, and is driven by a 2,500 hp, 450 rpm motor. The circulating water pump sumps are adjacent to the tower cold water basin.

Gas Removal and Atmospheric Emission Control Systems The primary atmospheric emission control system consists of the surface condenser/noncondensible gas removal equipment and the Stretford system. In addition, a secondary abatement system will be provided.

The noncondensible gases are removed from the condenser by two-stage steam jet ejectors. This steam is condensed in separate surface-type inter and after condensers which, along with associated piping, are mounted on a steel structure outside the turbine building. This system is designed to exhaust approximately 10,000 pounds per hour of noncondensible gases from the main condenser.

The Unit 18 Stretford unit designed to scrub this noncondensible gas has two modules, each capable of processing 300 lbs per hour of H_2S. More than 99 percent of the H_2S flowing to the Stretford system is converted to elemental sulfur. The elemental sulfur is stored in the molten state in an 8,000 gallon enclosed storage tank until it can periodically be removed for sale or disposal in an approved disposal site.

The overall hydrogen sulfide abatement efficiency of the surface-condenser/Stretford process depends on the percentage of the hydrogen sulfide withdrawn from the surface condenser with the noncondensible gases. This percentage is referred to as the surface condenser "partitioning efficiency" or "split".

The surface condenser "split" is dependent on the chemical composition of the incoming steam, and to a lesser degree on the design of the condenser. Unfortunately, the exact steam composition cannot be determined in advance so PGandE will install a secondary abatement system to remove the H_2S in condensate before it can be released to the atmosphere in the cooling tower. This system introduces hydrogen peroxide and a catalyst into the condensate line ahead of the condensate pumps to oxidize the H_2S to largely soluble sulfur compounds.

Electrical Systems Power generated at 13.8kV is stepped up to the 230kV transmission voltage by a 137 MVA three-phase, power transformer, located adjacent to the turbine-generator building. The 13.8kV transformer terminals are connected through a power circuit breaker to the generator terminals by cables enclosed in a metal duct. The 230kV transformer terminals connect to the transmission line through a power circuit breaker and circuit breaker disconnect switch. Approximately 4,000 feet of new transmission line will tie Unit 18 to an existing transmission line.

The unit will use a dual-voltage station power system, a 4,160 volt system for the circulating water pump motors and a 480 volt system for the condensate pumps, the cooling tower fan motors, and other plant auxiliary equipment motors. One auxiliary transformer is rated at 5,600kVA with a 13.8 kilovolt primary and a 4,160 volt secondary and two others are rated 3,300kVA with a 13.8 kilovolt primary and a 480 volt secondary.

A 21kV distribution line installed on wood poles along with the communication lines supplies emergency standby power through a 750kVA transformer to essential loads such as plant lighting, battery chargers, and fire pumps. These loads will transfer to the standby source automatically on failure of the normal source.

Supervisory System Since the Geysers units are designed for attendance by roving operators, conditions that could lead to equipment damage will result in an automatic unit shutdown or reduced load operation. These operators provide around-the-clock coverage seven days a week and make rounds of the units in their assigned areas approximately twice each eight-hour shift.

To permit control and monitoring of all the units by the plant operator in the central control room at Units 5 and 6, a computer-based supervisory control system provides a summary of each unit's status, signals malfunctions, and provides certain control functions. The Unit 5 and 6 master station contains two cathode-ray tube displays which show unit status and alarms, a control console, a teletype events recorder, and a backup annunciator system. From each plant site a remote terminal unit transmits unit status, alarm, analog and accumulator information to the master station which alarms, logs, displays, or stores the data for the plant operator. A total of 40 analog values such as pressures, temperatures, voltages, currents are transmitted from each unit. Twenty status points are used for pumps, valves, and breakers. Ten accumulators at each station store kWhr meter information.

From the master station the plant operator also can control the following functions for each unit: generator power output, voltage regulation, main breaker, and main steam valve. A communications link between PGandE's Power Control Center in San Francisco and master station allows the direct transmittal of kW, var, volt, kWhr, data, and breaker status. The master station also has a backup annunciator system that allows the plant operator to recall the full display of 20 alarm (annunciator) groups for any other unit and acts as a backup system when the computer is not in service.

Two-way radio communication between the plant control operator and the roving operators provides rapid response to problems.

Civil-Structural Features The Unit 18 turbine building, housing the turbine-generator and most of the mechanical and electrical equipment, is approximately 195 feet long, 85 feet wide, and 66 feet high. It is of steel frame construction with fluted metal siding. A level parapet at the top screens the view of the roof ventilators. Several ground level entry doors and a 21-foot wide rolling overhead door provide personnel and equipment access.

All foundations will be constructed of reinforced concrete. They are designed to the requirements of the Uniform Building Code (UBC) and Uniform Building Code Standards, 1976 Edition, and the Building Code Requirements for Reinforced Concrete (ACI 318-77) by the American Concrete Institute. Foundations will be designed using the strength method to resist all applicable loads, dead loads, live loads due to wind, seismic, and operating equipment.

Steel structures are also designed to resist all applicable loads--dead loads, live loads, and lateral loads.

Equipment will be designed for a combination of normal steady state operating stresses and seismic stresses. Seismic design will be based upon the supporting structure having constant simultaneous accelerations of 0.20g in a horizontal direction and 0.13g in a vertical direction. The turbine-generator and condenser designs are not based solely on seismic considerations, but on factors such as operating forces and core vibration. Based on seismic experience at other installations, the Toshiba's equipment will not suffer damage with a seismic acceleration of up to 0.5g.

CONSTRUCTION AND STARTUP Unit 18 construction started June 5 with site preparation work which will continue until next November. The site for Geysers Unit 18 requires excavating approximately 224,000 cubic yards of soil and rock. An additional 60,000 cubic yards of landslide debris will be removed from the onsite disposal area. Approximately 120,000 cubic yards of excavated material will be disposed of at Socrates Mine about one mile from the site, and the remaining 164,000 cubic yards will be disposed of on-site. Excavation to subgrade elevation requires some ripping, and it likely that light blasting also will be necessary. A concrete crib or reinforced earth retaining wall approximately 425 feet long with an average height of approximately 30 feet will be constructed on the west side of the site.

After completion of site grading, foundations will be placed. This takes about six months to complete. An on-site concrete batch plant will be provided to facilitate this work.

Erection of the structural steel and turbine building shell will require about four months. About four months is also required to complete the cooling tower.

Since equipment lay down area at the site is limited, major electrical and mechanical equipment for the unit will be delivered by rail to the construction storage yard in Healdsburg about 35 miles from Unit 18 and will be forwarded to the site as required during construction. Smaller equipment will be shipped by truck to Healdsburg or directly to the site.

Major equipment installation requires approximately six months. Startup testing will begin about 24 months from the start of construction. Following startup testing, initial turbine roll and a 48-hour full-load run, the unit is shut down for turbine-generator bearing inspection. At the end of a two-week bearing inspection period, the unit will be returned to service and released for commercial operation which is scheduled for October 1982.

A 4,000-foot transmission line to connect Unit 18 to an existing line will be built simultaneously with the major equipment installation. Transmission line construction consists of building access roads to tower locations, tower erection, right-of-way clearing, and conductor stringing. Each tower must have an access road for the delivery of material and equipment. Existing roads and spurs will be used whenever practicable. The transmission line traverses brushy and heavily timbered terrain so conductor stringing trails, 3 to 5 feet wide, will be cut continuously along the right-of-way. Approximately one-fourth acre at each tower location will be cleared to provide working space for tower assembly and erection. Trees within the 120-foot right-of-way will be cut or trimmed as necessary to provide electrical and physical clearance for the line's successful operation.

The overall construction period from the start of site work to commercial operation is about 30 months and the overall project from the start of site selection to commercial operation is 74 months.

GEOTHERMAL ELECTRIC PROJECTS FROM A USER'S VIEWPOINT

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The geothermal user's viewpoint in this case is somewhat unique. San Diego Gas & Electric Company, by virtue of its activity in geothermal exploration and development since 1972, is in a position to be considered not only a user of geothermal, but a producer as well through the activities of its wholly-owned subsidiary, New Albion Resources Co.

As the Supervisor of Fuel Development of SDG&E and the General Manager of NARCO, I can speak from experience on both sides of the negotiating table. I have given advice from the user's point of view to SDG&E's fuel acquisitions people as they labored to negotiate a contract to buy from a geothermal producer of hot water. As General Manager of NARCO, I am in the position of developing geothermal resources and negotiating contracts to sell some of NARCO's heat to third parties.

So much for the introduction--How does a utility, such as SDG&E, view risk in today's business climate? The answer to that question is very simple. SDG&E has an allowed rate of return of 10.59%. This is based upon 48% debt, having an inbedded interest cost of 8.1%; 14% preferred stock, at a cost of 8.2% and 42% equity. Out rates are supposed to return 14-1/2% on this equity. Let me put these numbers in perspective. In early March SDG&E sold $50 million of mortgage bonds which bear an interest rate of 16%. In mid-March we sold 2-1/2 million shares of common stock for $11.50 per share. The current dividend of $1.52 will yield 13.2% and those dividends are paid after taxes. When money borrowed to build a project costs more than you can earn on the project, there is no incentive to build that project and certainly no incentive to take any risk associated with the project. How does SDG&E view risks? Simple--don't take any risks which can be avoided! Is this attitude likely to change? My forecast is, there is no change in sight.

Does this take SDG&E out of contention as a possible market for producers of geothermal energy? Not likely. For all of its risk aversion, SDG&E still remains one of the best potential markets for any energy producer.

A recent article in FORBES MAGAZINE found that SDG&E had the third highest price per kilowatt of any utility in the country--5.9¢ per kilowatt hour for commercial customers. That was in March, 1980. Energy cost adjustment clause increases resulted in an average commercial price per kilowatt hour of 7.2¢ in May. In July it is expected to climb to 9.2¢. SDG&E's rate territory continues to expand at the rate of 5% annually and it is located just over 100 miles from a major source of geothermal heat in the Imperial Valley. But today, SDG&E has no commercial geothermal heat or power purchase contracts with domestic producers.

You may ask, "Why not?" With no incentive to spend its own money and with a high growth rate, what is SDG&E doing to obtain capacity for its existing and future customers? At the present time, most of SDG&E's capital expenditure for generation is going to the construction of San Onofre Units 2 and 3, a nuclear project which has been under way for ten years and which is expected to start generating commercial power in 1982 and 1983. San Onofre 2 and 3 will add 440 Mw of capacity from a reliable, proven generating technology to SDG&E's system. Even with the long delay and large capital costs in excess of $1,400 per kilowatt, energy and capacity from San Onofre in 1983 will cost only 5.0¢ per kilowatt hour at a 70% capacity factor. Restrictions on air quality and the use of oil make it very unlikely that SDG&E can build additional fossil fuel capacity in the next ten years. To move to coal gasification or coal liquids also involves risks which the utility is unlikely to be in a position to take until these fuel technologies are demonstrated. Coal-fired plants built in California are also risky from the standpoint of regulatory approval and environmental licensing.

San Diego has embarked on a program to purchase power from proven generating sources within a reasonable distance from its service territory. Where necessary SDG&E will build transmission facilities to make possible the reliable delivery of that power to the load center. The Company is building a major transmission line through the Imperial Valley to Arizona. SDG&E will purchase power under contracts negotiated with utilities in Arizona, in New Mexico and Mexico. In these contracts we are looking at proved direct-fired coal burning technology in Arizona and New Mexico and proved geothermal technology from the operating field at Cerro Prieto in Mexico.

For each of these purchase power contracts, there is a payment for capacity and a charge for energy taken. You may say, "But if you're paying for capacity, you are taking on some of the risk for that source of power." This is true, but the nature of the risk is one which is well known and understood to utilities and is less of a risk than building our own conventional electric generating station.

The prices may sound high by today's standards but are not out of line with the alternatives. The New Mexico purchase in 1983 will cost an average of 5.3¢ per kilowatt hour; the Arizona purchase, an average of 3.9¢ per kilowatt hour (it will increase to 6.5¢ in 1985 when a new coal plant becomes the source) and the geothermal power purchases from Mexico, an average of 7.8¢ per kilowatt hour. These prices in 1983 dollars include both capacity and energy charges. The Arizona and Mexico purchases include a guarantee of 100% capacity factor while the New Mexico purchase is assumed to be at 70%. With today's cost of low sulphur residual oil passing through $30 per barrel or about $5 per million BTU's, SDG&E's current cost of oil to fuel its existing generating stations is 50 mils per kilowatt hour. In 1983 it is projected to be 75 mils per kilowatt hour.

And how about the regulatory environment in California and for San Diego? I can say without hesitation, the California Public Utilities Commission continues to be very supportive of geothermal electric generation. In fact they have ordered SDG&E to aggressively pursue its geothermal plans and to file semi-annual reports with the CPUC, so they may readily follow our progress. The CPUC has granted SDG&E R&D expense treatment for the construction and operation of the proposed Heber binary geothermal plant. They have encouraged SDG&E through the operation of its fuel subsidiary, New Albion Resources Co., to take an active role in geothermal exploration and geothermal development. However, even such significant support as this does not permit the utility to raise significant amounts of capital for projects based on technologies which have not yet been proven successful in this country. SDG&E is having difficulty raising capital for proven technologies and normal transmission and distribution extensions to serve its growing service territory.

Why couldn't the CPUC simply approve a geothermal plant for SDG&E and assure that the carrying costs and operating costs associated with the project and any amortization necessary in the event of failure could be included in the utility's rates? SDG&E has not suggested this approach. Capital would still have to be raised and the very same thing that makes SDG&E attractive to geothermal developers; that is, a relatively high cost of electricity, makes it equally difficult for the Company and its regulators to continue to increase those rates. It is not really reasonable to expect the customers of one small utility, which is in a good position to use geothermal by virtue of geography, existing oil-fired plants and continuing growth, to bear the burden of verifying that the geothermal plants currently conceived will work and work well.

So what can the developer do to penetrate this best-of-all markets for geothermal without passing the burden of risk on to the utility? What are the contractual options that we can conceive of? The simplest one-party approach would be for the utility to own and operate the reservoir, finance and operate the plant and deliver the power to its service territory. However, this places the maximum risk on the utility, its shareholders and its customers. Another option would be for the utility to purchase geothermal heat from a reservoir developer and finance and build its own plant. This is a system which has worked successfully at the Geysers. However, the element of risk remains for the investment in the plant and transmission, and conceivably for the reservoir if the reservoir operator requires the utility to assure that its energy conversion technology will work satisfactorily.

What option might look good to a utility, such as SDG&E , at this point in time? It is the option we are now following for the bulk of our generating needs. We will purchase power from a plant owned by a third party and pay for capacity, where capacity is proven to exist, and energy as it is delivered.

To produce power for sale to a utility requires the cooperation of the geothermal resource developer, the plant owner and operator, and the utility as well as all the involved regulatory agencies. This is something which can be done and, in fact, is now being proposed. However, the utility does not want to pay for power which the plant cannot generate or to pay higher costs for energy because the plant or reservoir does not operate properly. Since the utility is unwilling to make such guarantees to the plant owner, it is likely the plant owner will be unwilling to make such guarantees to the reservoir owner. Therefore, the contracts connecting utility to plant and plant to reservoir must be skillfully written to provide suitable incentives to insure performance. The result would be three entities who stand to make a profit and serve a need if the total system functions properly.

Each of these entities should bear the risk for the successful operation of its portion of the project. If any of the three has to lean on the others for financial support, it can be expected that the project will topple like a string of dominoes. I have no doubt that most of the mechanisms are in place to allow such a project to be put together. For example: A reservoir could be financed with risk capital which could take advantage of tax benefits associated with drilling and operations. The greatest burden of capital is placed on the plant owner and operator.

It is here that Federal Loan Guarantees implemented at a reasonable pace could carry the risk of technological development. The utility will have to bear the risk of obtaining a transmission path from the site of the geothermal project to its service territory and the risk of no power if either the plant or the reservoir fails. I believe where a significant resource is indicated, utilities will be willing to carry this risk. It is normal to their business.

FINANCING POWER PLANT PROJECTS

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Introduction The financing of a geothermal power plant has a unique characteristic which is not present with conventional oil, coal, or nuclear power plants and which has slowed development of geothermal resources. That unique characteristic is the increased risk as perceived by utilities, banks and lessors and the unpredictability of those risks as perceived by insurance companies.

From a utility company perspective, the increased risk is the potential financial loss to the stockholders in the event the power plant is unable to economically produce electricity due to depletion, scaling or other problems. Such an eventuality could result in the utility having to "write-off" the value of the asset and pass the loss on to the stockholders. Banks, lessors and others share these same concerns for their stockholders; thus, are willing to finance power plants only if most of the financial risk is borne by the utility.

Retention of financial risk by the utility can take the form of a "hell or high water" power purchase contract wherein the utility makes payments even when no power is being produced, or an indemnity agreement with a plant lessor wherein the utility agrees to indemnify the lessor in the event he loses any of the tax or income benefits contemplated, or a credit agreement with a bank or other source of funds wherein the utility company's general credit backs up the obligation.

As a result of their perception of increased risk, utilities have been searching for ways to reduce the risk to their stockholders by shifting it either to the taxpayer in the form of a DOE grant or DOE loan guarantee, or the ratepayer in the form of Public Utility Commission (PUC) approvals or other sharing. Other potential methods for reducing risk may entail finding a plant lessor or other entity willing to accept some of the risk in exchange for a higher rate of return; obtaining insurance; or some combination of DOE loan guarantee, lease and insurance.

No attempt has been made to include the viewpoint of municipal utilities in this report. While they and their ratepayers may have the same concerns about the increased economic risks, the sources of financing are substantially different; thus, the risk of loss to the stockholders is not a concern.

Financing Options Included herein is a brief discussion of the financing alternatives available for construction of a power plant. This includes a brief description of the source of the funds, examples of utilities or others currently or prospectively using a particular alternative, advantages and disadvantages and who accepts the financial risk.

1. Traditional This alternative entails one or more of the following: common stock, preferred stock, bonds, bank borrowing and internal generation of funds from other operations. A utility typically utilizes various forms of short-term borrowing during construction and each of the other sources for financing the asset during the operational period. Pacific Gas & Electric Company is using these sources at The Geysers. With traditional financing, the common stockholders earn a return on their investment and, as a result, could be required to accept any loss. Since the benefits of geothermal power would be accruing to the customers, it may be possible to obtain PUC approval to amortize the loss in customer rates, thus relieving the stockholder. (Note that liquid dominated reservoirs with their potential for problems due to scaling, corrosion, reinjection, subsidence, etc. bring an element of increased risk for which utility stockholders may not receive additional compensation under current regulation.)

2. R & D Funds This is a special concept developed to fund SDG&E's share of the Heber binary commercial demonstration plant. Since the binary process is unproven for a commercial sized generating unit, the construction costs can be appropriately included in Research and Development, thus included in current customer rates as are other R & D costs.

   Several factors made the concept workable for this project which may or may not be available for other projects. First, the DOE has agreed to fund 50 percent of the cost. Second, EPRI and other utilities have agreed to fund a portion of the project in exchange for operating data and, in the case of the utilities, an ownership interest. Third, SDG&E has decided to reduce other R & D expenditures in order to commit the necessary R & D funds to the

Heber project. Finally, the PUC had determined that it is in the best interest of SDG&E's customers and the people of the State of California for this project to be undertaken in order to demonstrate the potential commercial value of geothermal energy from the Heber reservoir.

The advantages of these sources of funds to SDG&E are that there is no need to raise capital, there is no risk to the stockholder and SDG&E customer's rates are lower than they would have been using conventional financing. The risks are distributed to the various sources of funds: for SDG&E - the customers; for DOE - the taxpayers; for EPRI - all contributing utilities' customers; for direct contributions to the project from other utilities - depends on each utility's specific rate treatment.

3. DOE Cost Sharing Both the Public Service of New Mexico flash plant and the SDG&E binary plant will be partially funded by the DOE. As already discussed, this results in the DOE supplying a portion of the capital costs as well as accepting some of the financial risk in the event of project failure. The DOE cost sharing will result in a lower busbar cost. Disadvantages are the delay in starting construction and the potential of increased cost as a result of working with a government agency.

4. Leveraged Lease A leveraged lease, or tax leveraged lease, allows the equity investor to increase his yield from the lease by borrowing, or "leveraging", a large portion of the cost of the asset. The lease payments and asset are pledged to the lender as security. As a result the lender does not have recourse to the equity investor. Thus, the equity source typically invests 25-40 percent of the asset value and receives 100 percent of the tax benefits, any residual value at the end of the lease term, the portion of the lease payment not dedicated to repaying the debt and interest thereon and incurs no risk. No risk is incurred by the lessor because the lessee signs an indemnity agreement wherein lessee agrees to pay lessor for any loss of income due to ITC recapture or other event.

Since geothermal power plants qualify for the "alternative energy credit", a lessor can receive 15 percent of the asset cost as an energy tax credit in addition to the 10 percent investment tax credit (ITC). An additional benefit of the energy credit is that it is not subject to "recapture", or repayment to the IRS, in the event of loss or abandonment of the project as is the ITC. Ordinarily, a utility or other entity will not enter into a tax leveraged lease unless they are unable to utilize on a timely basis the tax benefits directly. If the lessee is paying little or no taxes due to tax loss carryforwards, current year tax losses or large depreciation deductions, he may be unable to fully utilize the tax benefits. In California and in some other states the utilities commission flows tax benefits through to the customers in the form of lower rates. Thus, if a utility in a "flow through" state is paying taxes, the customer benefits. However, if the utility is not paying taxes a leveraged lease can provide the same benefit to the customer. (There may be circumstances where the ITC would be retained by the lessee and the energy credit and/or other tax benefits received by the lessor or equity source.)

The lessee (utility) receives benefit from a leveraged lease because the lessor in effect shares a portion of the tax benefits by reducing lease rates. The effective lease rate would be 4 percent or more less than the lessee's borrowing cost from the sale of First Mortgage Bonds. This ultimately will result in a lower cost of electricity for the customer.

In addition to the advantage of lower rates and utilization by others of tax credits unusable by the utility, the sale leaseback of the asset represents an additional source of capital to the utility. A disadvantage of lease financing is that the utility has a fixed long-term obligation which is viewed by the financial community as a form of debt. This increases the perception by investors of increased risk for which they are not receiving an increased return. There is also a need for the lessor to be exempted from the holding company act. This will require PUC exemption and may require State legislation as well.

An independent reservoir engineer will be required to provide his opinion that there is reasonable evidence the reservoir will last longer than the lease term. Specifically, the lease term cannot be longer than 80 percent of the useful life of the reservoir to meet IRS requirements for the lessor.

There are some who feel that in return for the 25 percent tax credits the lessor should be willing to accept some of the financial risk associated with the power plant as a result of depletion of the reservoir, scaling, subsidence, etc. That concept has been discussed with equity sources with the result that the potential lessor(s) have been willing to accept certain discrete, low probability risks such as complete failure of the reservoir, but have been unwilling to accept a percentage share of all risks. This "sharing" of risk leaves the more probable risks with the utility, which may still be unwilling to construct the power plant.

In 1978, SDG&E completed a leveraged lease transaction on an oil-fired plant for $132 million. Public Service of New Mexico is currently negotiating for a leveraged lease on the portion of the Baca plant unfunded by the DOE. Another utility is evaluating whether to use traditional financing with the DOE loan guarantee or a leveraged lease with the DOE guarantee.

Risk Reducing Options

1. DOE Loan Guarantee The DOE loan guarantee is not a source of funds, but instead is a means of transferring risk from the borrower to the DOE. Instead of the general credit of a utility or other entity being utilized to support a borrowing, the guarantee is used. The guarantee will cover 75 percent of the project cost leaving 25 percent of the risk for the owner.

   Public utilities have been reluctant to utilize the DOE loan guarantee primarily because of the default provision which, in effect, requires the borrower to "default" in order to have the DOE repay the lender. This reluctance is due to cross-default provisions in other credit agreements which result in default on all agreements when there is default on one.

   As a means of avoiding this potential problem it has been suggested that a subsidiary or other entity borrow the funds and obtain the DOE loan guarantee. This too is perceived to be unacceptable from the viewpoint of a public utility due to concern that a utility subsidiary default will be viewed as a weakness in the parent company by the financial community or by stockholders.

   The DOE is aware of these difficulties and has been working on ways to allay utility concerns. A promising idea which the DOE is currently considering would involve a subsidiary borrowing the money and obtaining the DOE guarantee but would also include the following two items in an additional document. First, if the sale of the electricity is not generating sufficient income for the subsidiary to continue payments, the parent company could step in or if the problem is unsolvable the DOE would step in. Second, an agreement between the subsidiary and the DOE would result in transferring the collateral to the DOE in such an event. This structure is in the formative stages, but, if concluded, would allow the subsidiary to avoid default and would result in limiting the liability of the borrower through a non-recourse loan.

2. Insurance This method of reducing risk to the stockholders has not proven to be satisfactory to date due to its high cost and very limited coverage. Apparently no insurance company has been willing to provide insurance which covers the risk of partial or total shutdown of the plant due to degredation of temperature, pressure or flow rate of the reservoir or due to scaling, corrosion or environmental problems. Willingness to cover only catastrophic loss at high cost does not really help the power plant owner.

3. Purchased Power It may be possible in some circumstances for the resource developer to construct the generating facility and sell the power to the utility with a contractual agreement which removes the risks from the utility. In so doing, the developer must sell the power within an acceptable range of the cost of alternative sources of power while at the same time receiving a return which compensates for the risk.

   The developers are only willing to do this in order to accelerate development and use of the geothermal resource. It is not viewed as a long-term acceptable solution. Ultimately the utilities must fulfill their role of building power plants and purchasing fluid or steam from the developer.

4. Combinations The financing options and the risk reduction options can be combined in a number of ways. For example, the DOE loan guarantee and insurance can, and perhaps should, be used in conjunction with traditional as well as leveraged lease financing.

Requirements to Accelerate Construction of Geothermal Power Plants

1. PUC Action Utility commissions need to recognize both the potential for high cost and the high risk of geothermal power. This recognition must be translated into decisions which result in protecting the benefits to the customer. Additional action might be to include construction work in progress in the earning base of the utility. This would cover carrying costs during construction and reduce financial risk.

   In California, utility customers receive a very important benefit in return for accepting the costs of geothermal power. This benefit is the opportunity to develop a resource that is not imported, either in the form of fuel oil or purchased power. Additionally, the opportunity to reduce dependence on imported fuel oil could relieve customers from the threat of embargo and could result in a lower cost of power in the future.

2. Operating Results The units currently operating or in planning stages need a period of operation in order to supply data and hopefully reduce the perception of high risk.

3. State or Federal insurance coverage of risks insurance companies are unwilling to cover would protect stockholders and customers and make utilities more willing to move forward.

4. A state funded grant program similar to the Federal DOE grant program would be helpful.

Summary In summary, utilities' perception of increased risk when compared to conventional generating units and the potentially high busbar cost of electricity have been significant factors in preventing development of geothermal electric generation. Use of the DOE loan guarantee would be very beneficial in reducing the risk exposure to stockholders; however, DOE regulations regarding default have made utilities reluctant to utilize the guarantee. The DOE and others are working on a means to allay these concerns. Given the DOE's desire and mandate to accelerate development of alternative energy supplies, there is reason to be optimistic about the loan guarantee being utilized by utilities. Other means of reducing risk include: the lessor in a lease financing accepting a percentage of all risks, state or Federal insurance covering all risks and utility commissions' decisions which reflect their recognition of higher cost and risk.

Construction of power plants is likely to be slower than many would like until stockholder risks are adequately protected and until some geothermal plants have provided operating history which reduces the perception of risk.

ASSURING RESERVOIR PERFORMANCE

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Those who are involved in assuring reservoir performance or who want to be assured of reservoir performance are:

Reservoir Operator
Plant Owner/Operator
Utility
Customer/PUC - Municipal Government
Financial Institutions

The reservoir companies are risk takers. They will explore. They will test and measure. They will conduct reservoir engineering. They will conduct reservoir modeling. Their managements will commit funds to develop. Reservoir companies tend to be advocates of their product. They should be more candid. We have heard at this conference of hydrogen sulfide gas problems at The Geysers, injection system and injection well plugging at the SDG&E/DOE Geothermal Loop Experimental Facility, inadequate well production at the East Mesa Reservoir, high injection pressures at the Brawley Reservoir and other real reservoir difficulties. These must be addressed factually and solutions sought.

The utilities and/or plant constructors and operators are not risk takers. Under current regulatory structure, they have no incentive to take any risk. They are troubled by perceived risks which may be real or imagined. To put these perceived risks into perspective, the utilities or plant constructors and operators should be involved in exploration and development at an early date. They need a better understanding of the downhole environment. Before they make significant investments on any reservoir, they want to see the reservoir work. To accomplish this, as we have heard at this conference, they are building 10 MW facilities and no one is taking the commercial size step without outside help.

The utilities on the panel indicated they would buy geothermal heat if the reservoir operator would guarantee the reservoir for the life of the power plant. Some reservoir operators do not want to do this and those who will want the plant's operation guaranteed via fixed payments for heat or a long-term take-or-pay contract.

Utility customers as represented by public utility commissions or municipal governments would like to see geothermal on the line. It is apparent from our discussions that they will not see it unless the customers share somehow in the risk of getting things moving. Innovative rate treatment can provide incentives and this has been done in California. The Energy Exploration and Development Adjustment encourages utilities to participate in exploration and development. The Geothermal Loop Experimental Facility received favorable R&D expense treatment by the PUC. The Heber 50 MW binary demonstration has received support from the CPUC and R&D expense treatment. The Brawley 10 MW project is being handled primarily as an R&D expense treatment. With the exception of the 50 MW binary demonstration and a 50 MW flash plant at Heber, support has been limited to R&D efforts at 10 MW size.

The financial institutions will not take risks. They also need to be informed and educated about geothermal reservoirs and plants. The geothermal community should continue to involve the financial institutions.

The workshop has identified some basic observations:

- Sandstone reservoirs are better understood than fractured reservoirs.
- A lot of hard data can be obtained for a given reservoir regarding its size, depth, temperature, heat transfer characteristics and fluid quality or chemistry.
- Utilities generally do not understand the below-ground technology. If they accept the existence of a reservoir, they are concerned that the conversion technology will not work well enough to be cost effective.
- Heber is probably the most thoroughly measured, tested, modeled and reviewed reservoir in existence. Yet, no independent risk-taking action has been observed regarding plant construction on this reservoir.

- A 10 MW plant built five years ago on a reservoir, such as Heber, would have greatly helped everyone's need for assurance even though it would not thoroughly test reservoir longevity.

The workshop recommends the following actions:

- Utilities should develop a technical staff capable of understanding reservoir information; preferably this would be developed as in-house expertise. The utilities should get involved early and be willing to carry the risk of loss of generating capacity if a geothermal project should fail.
- Reservoir companies should carry the risk of their investment in the reservoir. They should not require take-or-pay contracts.
- Reservoir companies should work to involve the utility at an early date.
- Reservoir companies should avoid the pitfalls of advocacy and be more candid with their potential customers.
- Utility customers should pick up the risk and the benefits of early geothermal development undertaken by utility companies.
- Public utility commissions or municipal governments should give utilities incentives to develop, such as construction work in progress, R&D expense treatment of early plants, rapid write-off of commercial plants and amortization of geothermal plant investment if the project should fail.
- Financial institutions need to become informed of the realities of reservoir exploration, development and operation. Utilities should work to inform the financial institutions of the facts.
- Electric Power Research Institute should publish its geothermal reservoir handbook. EPRI should continue to inform utilities of developments in geothermal technology, both in the reservoir and in the plant.
- All of the parties interested in reservoir assurance should share a portion of the risk. They should recognize the very real need for operating hardware in the field and get to work together to build it.

ACHIEVING TECHNICAL PERFORMANCE

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Introduction The group discussions relating to achieving technical performance addressed the facilities for handling, conversion and utilization of geothermal energy for electric power production. The discussion specifically excluded reservoir performance as this was the subject of a parallel workshop.

It became obvious during the session that time would not permit adequate coverage of the topic without extensive generalization in areas where the problems are not generic but in fact very site specific. The problem of achieving technical performance can be totally different from one site to the next depending on the characteristics of the energy source and the site conditions that may affect the facility design.

Under these constraints, the group addressed the issue of performance achievement as related to standards of measurement or goals. It was generally agreed that an acceptable measure of performance should relate to plant availability. If the plant has a high annual availability factor, then it should be capable of sustaining a good capacity factor as well. While there was no overwhelming agreement on the concept that plant availability would necessarily equate directly to capacity factor, it was generally accepted by the group that plant availability was a good measurement of acceptable technical performance. A goal of 90 percent was proposed by the group.

Performance Problems The problems relating to achieving technical performance identified by the group are summarized below. The problems cited are not necessarily generic but rather related to the knowledge and experiences of members of the discussion group based on operating experience, special studies, or research and development work. They covered Geysers dry steam operation and hydrothermal direct flash and binary facilities.

- Production Well Piping

  Reliability and cost continues to be a problem. Where downhole pumping is required on the low to medium temperature hydrothermal reservoirs, redundancy is the current solution to achieving good plant availability. For the moment it appears that industry will solve this problem.

- Well Completion

  Representatives of the CFE indicated that problems are being experienced at Cerro Prieto with well casing and joint seal failures. This problem has had a continuing impact on steam production and requires a high well redundancy ratio in order to support their capacity factor goals. They believe this problem can be solved by industry without need for any special R&D.

- Steam Separation and Scrubbing

  Technology and equipment for steam separation and scrubbing appears to be in hand based on limited operational experience. Performance is generally predictable. However, scaling and fouling problems are site related, not generally predictable and require equipment outages for descaling. Solutions are not generally available on a generic basis.

- Two Phase Flow

  Problems of designing for two phase flow are not well defined. To date, system designs have avoided two phase flow through the use of well head separators, pumped wells and production island concepts. Some form of R&D would be useful to the plant designer. Indications are that two phase systems are being successfully operated in Japan.

- Steam Quality Measurement

  Maintaining design steam quality in a hydrothermal flash cycle is primarily a function control dynamics and separator/scrubber performance. The consequences of decreasing steam quality which usually result from deteriorating separation performance, are solids buildup in the turbine and reduced turbine performance.

  The consequences of low steam quality could be materially reduced if online steam quality monitoring was available to the plant operator. According to the members of the discussion group, online equipment of this type is not available. Further investigation was recommended.

- Environmental

  H_2S abatement systems are being installed at The Geysers which employ technology developed for other industries. Other new concepts are also being tested for next generation applications. According to discussion group members, ongoing development of alternative processes will be necessary before this problem is fully and economically controlled.

  Another problem area involves condensate pH control when ammonia is present. Online monitoring techniques are not presently available to the plant operator for proper control. Hardware development is needed in this area.

Summary In relating technical performance to the goal established at the beginning of the discussions, the consensus of the group, in the opinion of the writer, on the status of achievement can be summarized as follows:

1. Geysers dry steam is in a commercial operation mode but still experiencing operational and environmental problems that must be resolved if full success is to be achieved.

2. Hydrothermal flash steam is in a commercial operation mode around the world and on the threshold within the United States. At Cerro Prieto the CFE appears to be achieving 90 percent availability.

3. Commercial acceptance of the binary cycle by industry will not occur until the process is successfully proven in a demonstration plant.

OBTAINING A LICENSE AND PROTECTING THE ENVIRONMENT

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Originally these two were to be handled in separate workshops but since these two subjects are closely related they were combined. The workshop participants did, however, try to focus the discussion on the two separately, though we were not always successful.

Fortunately, we had two people in our group who are intimately involved in licensing proceedings in the only two states that have considered geothermal power plants, California and New Mexico. Lavonne Blucher-Nameny of PGandE reviewed the California procedure and Dave Sabo of Public Service Company of New Mexico covered New Mexico.

Obtaining a License

The California Licensing Process: The major aspects discussed were:

- The permit licensing process is under the direction of the California Energy Commission. A geothermal power plant receives special consideration, either (1) a 9-month Notice of Intention (NOI) plus a 9-month Application for Certification (AFC), with the NOI focusing on the site selection and the AFC on detail plant design; or (2) a 12-month AFC combining both aspects if a steam supply has been proven. This is in contrast to the conventional generation system which requires a 36-month process (18 NOI plus 18 AFC).

- It was originally intended to be a "one stop shop" but it is not. Agreements are needed with local, county, and state agencies. Reaching agreement is the preferable approach. Items not agreed to require a adjudicatory hearing with sworn statements and witnesses.

- Public involvement is encouraged and specifically invited through a Public Advisor.

- The process is very institutionalized with a final decision up to the Commission itself. Positions are essentially presented by the Commission staff and the applicant staff.

- One good feature of the process is that the CEC has a specified time limit in which to act. The applicant must make sure, however, that the proceedings are not suspended and the time pressure removed.

- Safety and reliability are involved in the AFC review process. This requires detailed designs and drawings much earlier in a project than is normal practice.

- The Energy Commission is presently under scrutiny by the California legislature and its makeup and role may change in the future.

Comment:

- The process is modeled very much after our judicial process with two sides, applicant and staff, presenting their case to a judge, the Commission. Findings and conclusions that both sides agree to are equivalent to plea bargaining. The difficulty with this process of conflict resolution is that it requires both sides to approach the process with advocacy position that cannot be easily abandoned.

- There is no reward to the CEC staff for making decisions under uncertainty. This leads to numerous studies, demonstrations, and monitoring programs during and as part of the permit conditions.

Editorial note: Geysers Unit 17, recently permitted, is the first power plant to complete the process since the CEC was instituted 5 years ago.

The New Mexico Licensing Process:

- The New Mexico process is not as institutionalized as California. Government is not as strongly organized at the county level. There is no centralized agency to handle the licensing process and a number of permits are required.

- If there is federal involvement, the process becomes more institutionalized.

- There is only one major public interest group composed primarily of technical personnel from the Los Alamos Laboratories. The group has both supported and opposed the utility.

- The resolution of concerns under the Indian Religious Freedom Act involved the Bureau of Indian Affairs (a federal agency) funding the legal opposition to a geothermal power plant funded by DOE (a federal agency).

Editorial note: A geothermal resource is mineral in California and water in New Mexico.

Synopsis:

1. Obtaining a license is different in each state.

2. In both systems approximately 3 years is the minimum time required to prepare the document and go through the hearing process.

3. Resolution is reached using the adversary/plea bargaining concept borrowed from our legal system. There is some question whether this is the best way to resolve the issues involved.

4. The solution to licensing lies in societal perceptions and legislative actions which are not amenable to technical or managerial fixes. They are at best vernier adjustments.

5. Persist, grin, and bear it.

* * * * * * *

Protecting the Environment

The discussion was limited by both time and enthusiasm. Participants felt it was like plowing over old ground, as environmental concerns are dealt with in a number of forums.

However, some general areas were discussed, and are capsulized below.

Environmental Concerns Amenable to Technical Solutions:

- Air/H_2S Abatement

  A number of H_2S treatment processes are being considered. Because of the variety of resource compositions, there will probably never be a single best solution to H_2S abatement. Trace elements that may be vented to the air will receive increasing emphasis. The reports of detecting benzene in geothermal steam will be of concern until better measurements are obtained.

- Water

  Water Supply is becoming a major factor in geothermal development outside of The Geysers. Increasing concern is being focused on resource to surface water coupling. Impact of geothermal development on associated hot springs and the possible impact of reinjection on associated water supplies are two areas receiving attention.

- Seismicity

  Studies are ongoing.

- Solid Waste

  The composition and disposal of solid waste will require increasing attention. The EPA solid waste regulations exclude geothermal at this time, but they are sampling and analyzing solid waste at The Geysers.

Environmental Concerns Not Amenable to Technical Solutions:

It was generally agreed that areas of environmental concern such as socio-economics, ethnic and historical considerations, and land use are really not amenable to technical solutions.

Comment:

It was a general feeling that most of the environmental problems, real or perceived, were under study. The difference that exists is in relative importance and therefore the amount of funding needed to study the particular problem.

Considerable discussion took place regarding the involvement of the Environmental Protection Agency (EPA) in geothermal development. Geothermal enjoys certain privileges, but it is not known whether this will continue. The possibility exists for EPA to become involved in solid waste, air, and water standards and reviews. No real answer as to how to deal with the EPA was forthcoming.

There was a general consensus that the environment can be protected but that absolute certain solutions do not exist, nor will ever exist for all environmental concerns, and that the relative importance of environmental concerns will always be quite site specific.

SESSION 7

INTERNATIONAL POWER DEVELOPMENT REPORTS

GEOTHERMAL POWER PLANTS IN CHINA

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Introduction China's vast geothermal potential has been long recognized, but it is only recently that a systematic program has begun to map and characterize the resource. It seems clear that a serious effort is underway to develop and exploit the low-temperature geothermal fields that are abundant in the country. Accelerated growth of installed geothermal electric generating capacity will likely continue for the near future as local industry takes advantage of the infusion of established technology already gained in other countries.

This paper is based on information from three main sources: An article in The China Business Review by Fountain [1]; A paper presented at the 1979 Annual Meeting of the Geothermal Resources Council by Finn [2]; and several technical reports (in Chinese) that were sent to the author by Professor Cai Yi-Han of Tianjin University.

Summary Nine small experimental geothermal power plants are now operating at six sites in the People's Republic of China. These range in capacity from 50 kW to 3 MW, and include plants of the flash-steam and binary type. All except two units utilize geofluids at temperatures lower than 100°C. The working fluids for the binary plants include normal- and iso-butane, ethyl chloride, and Freon. The first geothermal plant came on-line in 1970, the most recent ones in 1979.

Figure 1 shows the location of the plants. Major cities are also shown for reference. Table 1 contains a listing of the plants and some pertinent characteristics. The total installed capacity is 5,186 kW, of which 4,386 kW is from flash-steam units.

In the following sections we shall give an example of the results of exploratory surveys, and show system diagrams, technical specifications, and test results for several of the power plants.

Heat flow studies China's hot springs are being developed in at least twenty-two Provinces, Municipalities and Districts [2]. All told, there are over 2500 such geothermal sites in the country, including the high-temperature field at Yangbajing in the Himalayas of Tibet, several promising areas in southeast China (in Kwangtung, Fujian, Taiwan, Kiangsi and Hunan Provinces), and the Tianjin field, 93 mi (150 km) southeast of Peking, where over 200 wells have been drilled in a 146,000 acre (590 km^2) tract [1].

The results of heat flow and temperature gradient surveys have been reported by the Geothermal Group of the Geological Survey of China [3]. These studies were conducted in an area extending south from Peking to Nanking and covering an east-west span of about 250 mi (400 km). Eleven areas where test holes were drilled are shown in Figure 2. Technical data from the test wells are given in Table 2. Thermal gradients range from about 5-23°F/1000 ft (9-41°C/km). The normal or average gradient, worldwide, is about 18°F/1000 ft (33°C/km). The heat flux ranges from 0.72-2.01 μcal/cm^2·s (cf. 1.5 μcal/cm^2·s, normal heat flux). Thus, the geothermal resource in this region is low-grade and will likely require the use of binary plant technology in order to allow its exploitation for electric power.

Huitang 300-kW plant Hot water from two wells is pumped under a pressure of 57 lbf/in^2 by two pumps, each having a capacity of 700 gal/min (160 m^3/h) and requiring 30 kW of power, to a flash tank having a volume of about 425 ft^3 (12 m^3). The liquid is flashed to a subatmospheric pressure of 4.3 lbf/in^2 (29.6 kPa) and a temperature of 154.4°F (68°C). The steam is then used in a simple Curtis-type steam turbine, as shown in the flow diagram in Figure 3 [Prof. Cai Yi-Han, personal communication]. The power plant generates 300 kW from a steam flow rate of about 95,000 lbm/h (43.2 Mg/h), with a "Second Law" utilization efficiency (based on the exergy of the geofluid at the wellhead) of about 32%. This assumes that about 13.5% of the geofluid (taken to be saturated liquid at the inlet to the flash tank) is converted into steam. Some of the technical particulars of the plant are shown in Table 3. The waste geofluid from the flash vessel is put to further use in greenhouses, and supplies domestic hot water for residences and a convalescent home.

Yangbajing 1- and 3-MW plants The flow diagram in Figure 4 shows the arrangement of the flash-steam (actually, separated steam) plants at Yangbajing in the Himalayas of Tibet. The

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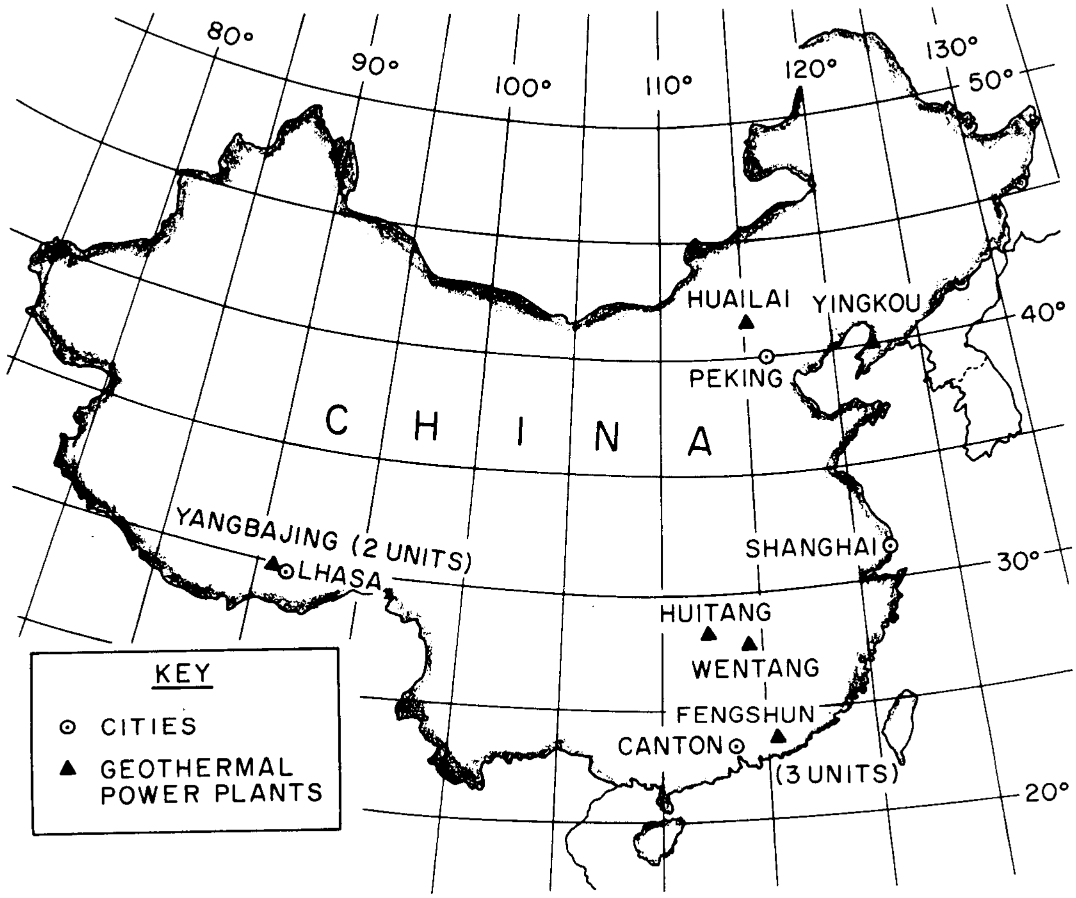

Fig. 1 Map of China showing sites of geothermal power plants [after [1]].

Table 1. Summary of Geothermal Power Plants in P.R.C.

Plant Name	Location	Start-up Date	Plant Type	Working Fluid	Water Temp.	Rating
Fengshun	Fengshun, Kwangtung					
Unit No. 1		Oct. 1970	Flash-steam	Water	91°C	86 kW
Unit No. 2		Sept. 1971	Binary	Isobutane	91°C	200 kW
Unit No. 3		1979	(n.a.)	(n.a.)	91°C	250 kW
Wentang	Ichun, Kiangsi	Sept. 1971	Binary	Ethyl Chloride	67°C	50 kW
Huailai	Huailai, Hopei	Sept. 1971	Binary	Ethyl Chloride; N-butane	85°C	200 kW
Huitang	Ningsiang, Hunan	Oct. 1975	Flash-steam	Water	92°C	300 kW
Yingkou	Xiongyue, Liaoning	April 1977	Binary	N-butane; Freon	75-84°C	100 kW
Yangbajing	Yangbajing, Xizang					
Unit No. 1		Sept. 1977	Separated-steam	Water	150°C	1000 kW
Unit No. 2		1979	Separated-steam	Water	150°C	3000 kW

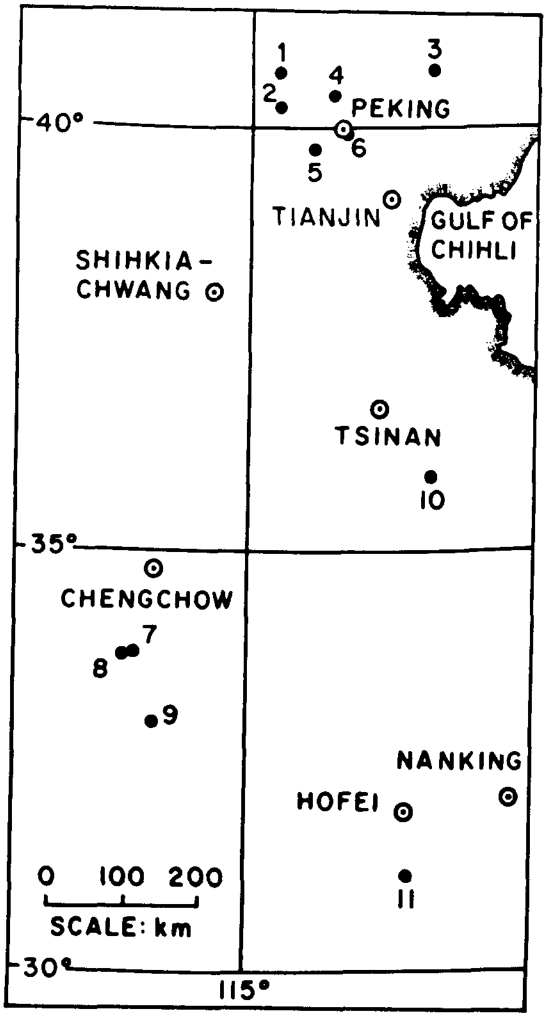

Fig. 2 Location of test holes for heat flow survey in east-central China. Key: ⊙ Cites, ● Test sites [after [3]].

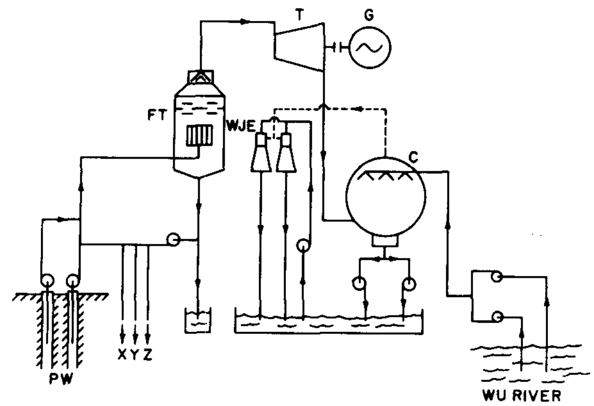

Fig. 3 Simplified flow diagram for 300 kW flash-steam geothermal power plant at Huitang. Key: PW = Production wells; FT = Flash tank; T = Turbine; G = Generator; C = Condenser; WJE = Water-jet ejector; X = Hot water to domestic uses; Y = Hot water to Huitang Convalescent Home; Z = Hot water to greenhouses.

Table 2. Results of heat flow survey in east-central China

Test site(1)	Well no.	Location E	Location N	Elevation(2) m	Depth m	Range of meas., m	Temp. grad. °C/km	Thermal cond. mcal/cm·°C·s	Heat flux μcal/cm²·s
1	13	115°30'	40°41'	1300	529	100-330	12.5	5.8	0.74
2	103	115°26'	40°12'	750	733.2	183-733	13.8	5.8	0.80
2	46	115°26'	40°10'	875	418	200-400	8.9	7.4	0.63
3	10	117°51'	40°35'	na	671.8	441-620	12.7	5.7	0.72
4	72-7	116°16'	40°20'	525	369	160-340	16.4	7.9	1.21
4	72-5	116°15'	40°25'	585	682.9	480-610	19.9	6.8	1.35
5	-	115°57'	39°44'	na	507	300-500	12.7	5.7	0.74
6	21	116°27'	39°55'	36	700	506-700	19.4	10.3	2.01
6	22	116°29'	39°55'	36	1030	860-1030	13.7	10.6	1.45
6	24	116°26'	39°55'	36	940.5	837-940	19.5	9.5	1.85
7	18-8	113°23'	33°47'	80.7	683	217-683	29.2	6.0	1.76
8	101	113°12'	33°47'	na	580.9	148-326	26.4	6.5	1.71
9	33580-1	113°50'	32°56'	135	117	30-110	18.2	6.4	1.17
10	350	117°40'	35°52'	173.2	735.4	645-735	16.4	7.0	1.15
11	56	117°19'	31°0'	38.3	749.9	100-308	41.2	4.6	1.88
11	135	117°19'	31°0'	41.5	700	134-229	36.4	4.9	1.80

(1) See Fig. 2. (2) of wellhead above sea level.

Table 3. Technical specifications for Huitang geothermal power plant

Year of start-up	1975
Plant type	Single-flash steam with pumped wells
Turbine data:	
Type	Single-cylinder, single-flow, 2-stage impulse
Rated capacity	300 kW
Speed	3000 rev/min
Inlet pressure	3.84 lbf/in^2 (26.5 kPa)
Inlet temperature	150^{o}F (65.6^{o}C)
Exhaust pressure	1.45 in Hg (4.9 kPa)
Steam flow rate	∿95,200 lbm/h (43.2 Mg/h)
Condenser data:	
Type	Barometric jet
Volume	176 ft^3 (5 m^3)
Pressure	1.45 in Hg (4.9 kPa)
Cooling water flow rate	880-1429x10^3 lbm/h (430-648 Mg/h)
Gas extractor data:	
Type	Water jet
No. of sets	2
Water consumption	71,400 lbm/h (32.4 Mg/h)
Heat rejection system:	
Type	Once-through, water from Wu River

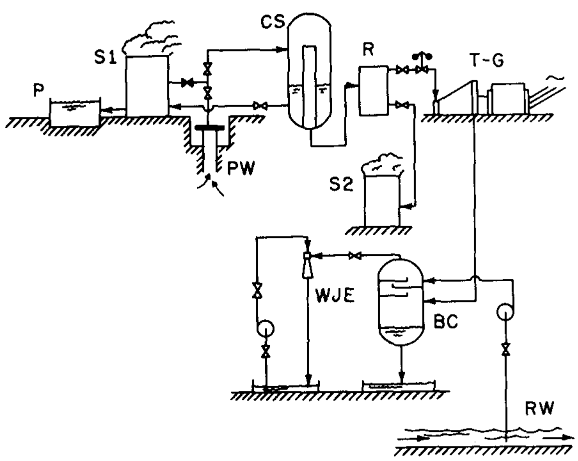

Fig. 4 Simplified flow diagram for 1- and 3-MW separated-steam geothermal power plants at Yangbajing. Key: PW = Production wells; CS = Cyclonic separator; S1 = Wellhead silencer; P = Water-holding pond; R = Receiver; T-G = Turbo-generator; S2 = Station silencer; BC = Barometric condenser; WJE = Water-jet ejector; RW = River water.

resource temperature of 302^{o}F (150^{o}C) is the highest of any geothermal plant in China. Conventional equipment appears to be in use at Yangbajing, including cyclonic separators, axial-flow turbines, barometric condensers, and water jet ejectors for the noncondensable gases. About 80% of China's installed geothermal capacity is located at this site not far from the city of Lhasa. No other technical data on these plants are available at this time.

Wentang 50-kW plant This binary plant, located in Kiangsi province, has been producing 50 kW since 1971 although it also serves as a test-bed for binary technology. A photograph of the powerhouse is given in Figure 5. The source of heat is a hot spring having water at 153^{o}F (67^{o}C), making this the lowest-temperature geothermal binary plant in existence. It was built and operated jointly by the Hydrological-Geological Team of Kiangsi province and the Research Group on Energy Sources of Tianjin University [4].

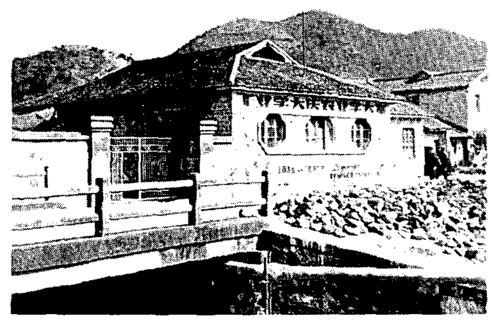

Fig. 5 Site photograph of the 50 kW Wentang binary geothermal power plant. [Photo courtesy of Professor Cai Yi-Han]

Figure 6 shows the plant layout. The working fluid is ethyl chloride (C_2H_5Cl). The geofluid may be directed through the two vertical shell-and-tube evaporators in any of four modes: (1) left heater only (V1 and V3 open); (2) right heater only (V2 and V4 open); (3) left and right in parallel (V1, V2, V3 and V4 open); (4) right and left in series (V2, V3 and V5 open). In this way a variety of tests may be performed. The unit uses two condensers having low-winged, spiral-threaded tubing, giving nearly twice the efficiency of straight, smooth tubing. Two types of expanders have

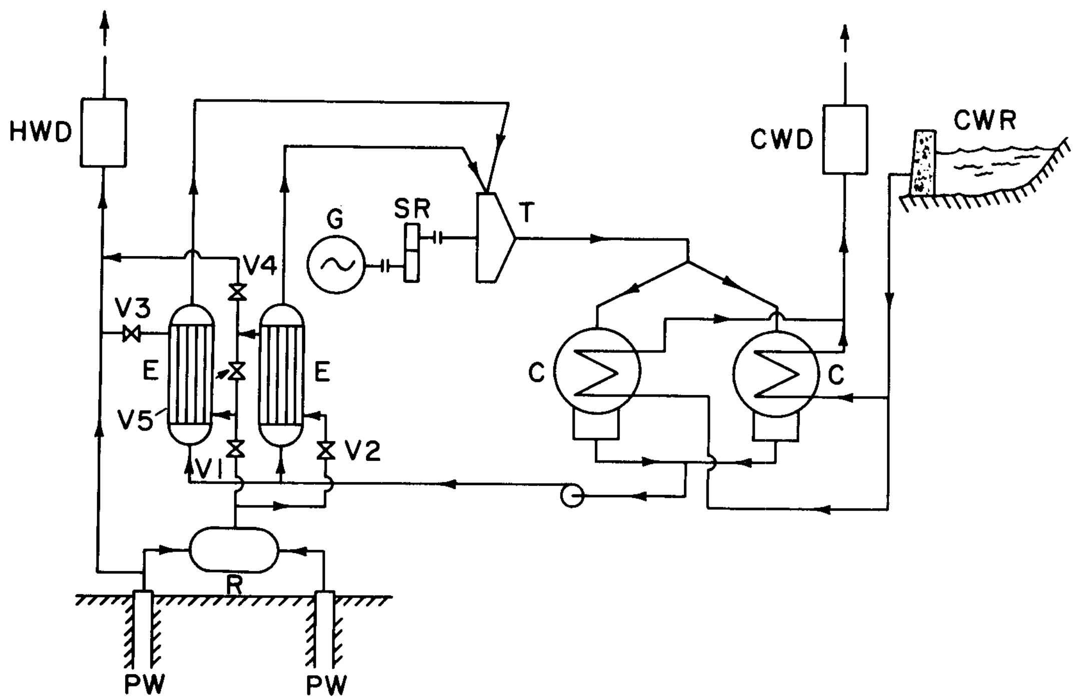

Fig. 6 Simplified flow diagram for 50 kW binary geothermal power plant at Wentang. Key: PW = Production wells; R = Receiver; V1-V5 = Hot water flow control valves; E = Evaporators; HWD = Hot water disposal; T = Turbine; SR = Speed reducer; G = Generator; C = Condensers; CWR = Cooling water reservoir; CWD = Cooling water disposal.

been employed. The original design used an axial-flow turbine that had an efficiency of about 70%; the most recent design uses a radial-inflow machine capable of efficiencies as high as 82.5%.

At first the geofluid had to be pumped to the plant, but stimulation using water from the adjacent river resulted in artesian flow and eliminated the deep well pumps [4]. The flow rate of hot water increased to $200\text{-}220 \times 10^3$ lbm/h (90-100 Mg/h) with a pressure head of about 7 lbf/in^2 (5 m H_2O). Furthermore, since the powerhouse is situated about 10 ft (3 m) lower than a portion of an adjacent river, a dam was built to create a small reservoir from which cooling water flows under its own head to the condensers. Thus relatively little station power, about 7.5 kW on the average, is required to operate the plant.

Table 4 shows the results of test runs conducted on April 17, 1978 [5]. The evaporators were connected in parallel for the tests. From the data shown, the plant has a resource utilization efficiency (Second Law) of about 19% (gross) and 15% (net). The cycle efficiency (First Law), i.e., work output divided by heat input, is 5.2% (gross) and 4.2% (net).

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Table 4. Technical specifications for Wentang geothermal power plant(1)

Year of start-up	1971
Turbine data:	
Type	Radial inflow
Gross power	51.8 kW
Net electrical power	42.1 kW
Speed, turbine/generator	4500/1000 rev/min
Secondary working fluid	Ethyl chloride, C_2H_5Cl
C_2H_5Cl inlet pressure	44.1 lbf/in^2 (304 kPa)
C_2H_5Cl inlet temperature	115.9°F (46.6°C)
C_2H_5Cl exhaust pressure	20.9 lbf/in^2 (144 kPa)
C_2H_5Cl exhaust temperature	71.8°F (22.1°C)
C_2H_5Cl mass flow rate	19,470 lbm/h (8830 kg/h)
Geothermal fluid data:	
Inlet temperature	149.5°F (65.3°C)
Outlet temperature	123.4°F (50.8°C)
Mass flow rate	130,500 lbm/h (59,200 kg/h)
Condenser data:	
Type	Dual, shell and tube
Pressure	21.2 lbf/in^2 (146 kPa)
Cooling water inlet temperature	58.8°F (14.9°C)
Cooling water flow rate	398,000 lbm/h (180,500 kg/h)
Heat rejection system:	
Type	Once-through, gravity-feed from reservoir

(1) Based on Tests No. 21-5 and 21-6 carried out on 4-17-78.

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AHUACHAPAN GEOTHERMAL POWER PLANT, EL SALVADOR

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Introduction The Ahuachapan geothermal power plant has been the subject of several recent reports and papers (1-7). This article is a condensation of the author's earlier writings (5-7), and incorporates new information on the geothermal activities in El Salvador obtained recently through a telephone conversation with Ing. R. Caceres of the Comision Ejecutiva Hidroelectrica del Rio Lempa (C.E.L.) who has been engaged in the design and engineering of the newest unit at Ahuachapan.

El Salvador is the first of the Central American countries to construct and operate a geothermal electric generating station. Exploration began in the mid-1960's at the geothermal field near Ahuachapan in western El Salvador. The first power unit, a separated-steam or so-called "single-flash" plant, was started up in June 1975, and was followed a year later by an identical unit. In July 1980, the Comision Ejecutiva Hidroelectrica del Rio Lempa (C.E.L.) will complete the installation of a third unit, a dual-pressure (or "double-flash") unit rated at 35 MW. The full Ahuachapan plant will then constitute about 20% of the total installed electric generating capacity of the country. During 1977, the first two units generated nearly one-third of all the electricity produced in El Salvador.

C.E.L. is actively pursuing several other promising sites for additional geothermal plants. There is the possibility that eventually geothermal energy will contribute about 450 MW of electric generating capacity. In any event it appears that by 1985 El Salvador should be able to meet its domestic needs for electricity by means of its indigenous geothermal and hydroelectric power plants, thus eliminating any dependence on imported petroleum for power generation.

Reservoir characteristics The Ahuachapan geothermal field is located in westernmost El Salvador about 18 km (11 mi) east of the Rio Paz which forms the international boundary with Guatemala. The area consists of moderately sloping terrain on the northern side of a string of volcanic mountains. Within the 3000 ha (7400 acre) geothermal region, there are a number of areas of active surface thermal manifestations including fumaroles, hot springs, steaming ground, and boiling mud pools. The reservoir is believed to consist of the following layers of rocks (top to bottom): brown tuffs and pyroclastics, andesites, agglomerated tuffs and pyroclastics, andesites, young agglomerates, Ahuachapan andesites, and old agglomerates (basement rock). The Ahuachapan andesites serve as the aquifer, the permeability of which is created through fractures in an otherwise hard formation. The young agglomerates constitute the cap rock for the reservoir. The temperature of the geofluid in the reservoir is about 230°C (445°F). The aquifer is believed to be recharged from a volcanic lake to the south of the field.

Drilling programs About 30 wells have been drilled in the field. The spacing between wells is not less than about 150 m (490 ft), with an average density of one well per 23 ha (55 acres). However in the central portion of the field there is one well per 11 ha (27 acres). Figure 1 shows the drilling program for well AH-26. The well was completed in 49 days to a depth of 804 m (2644 ft); the average penetration rate was about 2 m/h (6 ft/h). Drilling mud was used for the first 400 m (1310 ft) and water was used while drilling through the aquifer.

A typical production well has the following configuration: 17-1/2 in dia. hole with a 13-3/8 in casing cemented to a depth of about 100 m (328 ft); 12-1/4 in hole with 9-5/8 in casing to 400 m (1310 ft) or to the top of the reservoir; 8-1/2 in hole through the production zone. In some cases, a 7-5/8 in slotted liner is hung from the 9-5/8 in casing, although the formation is sufficiently hard to prevent cave-in for many wells. Reinjection wells are completed in a similar way except that they are drilled deeper, into the basement rock, and fitted with a 7-5/8 in casing down to the top of the basement to prevent the reinjected fluid from entering the aquifer.

Steam gathering system The main production area of the field is shown schematically in Figure 2. The area to the south of the power house consists of surface thermal mani-

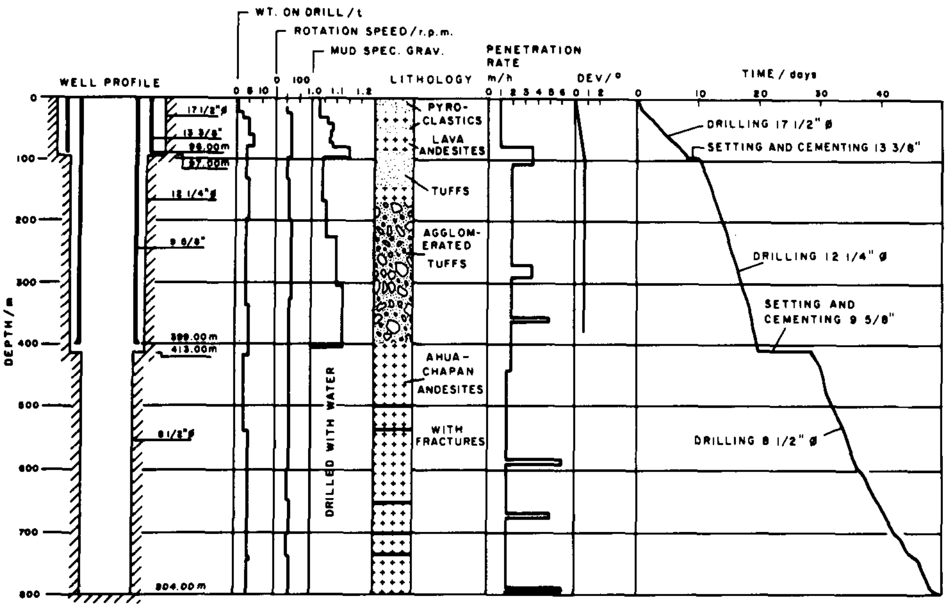

Fig. 1 Drilling program for well AH-26 (6).

festations. The solid lines indicate the general paths of the main steam lines from each well to the receivers for Units 1 and 2 at the plant; the actual pipelines contain numerous expansion bends which have been omitted in the figure for clarity. The dashed lines indicate reinjection lines. Steam lines are made of ASTM A-53 Grade B seamless carbon steel pipe and are insulated with blocks of calcium silicate. The insulation is wired onto the pipes, covered with composite kraft paper/aluminum sheet, and enclosed within a jacket of galvanized steel. Reinjection pipes are uninsulated. For the operation of Units 1 and 2, of the nearly 600 kg/s (9300 gal/min) of liquid

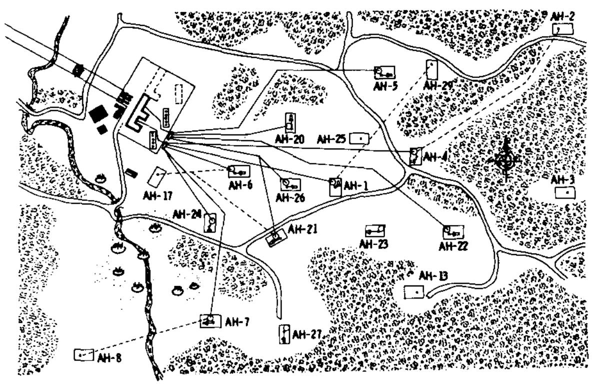

Fig. 2 Plant and well arrangement (7).

which is separated at the wellheads, about 370 kg/s (5720 gal/min) is reinjected into the basement rock. The remainder of the liquid is disposed of by means of surface discharge and evaporation, with the effluent from several wells being collected and conveyed through a covered concrete channel to the Pacific Ocean, a distance of roughly 75 km (47 mi).

The total amount of dissolved solids in the liquid at the wells averages about 18,400 ppm or 1.84%. The main constituents are: chloride (10,430 ppm), sodium (5690 ppm), potassium (950 ppm), silica (537 ppm), calcium (443 ppm) and boron (151 ppm). A large number of other elements are present in concentrations less than 100 ppm. Noncondensable gases amount roughly to 0.05% by weight of the total well flow, or about 0.2% of the steam flow. These gases consist mainly of carbon dioxide (86.8% by volume) and hydrogen sulfide (12.1% by volume), with small amounts of hydrogen, nitrogen, ammonia and methane.

Energy conversion systems The power units comprise: (1) an auxiliary turbo-generator used for start-up; (2) two single-flash 30-MW sets; and (3) one dual-pressure, "double-flash" 35-MW set.

A 1.1 MW, noncondensing geothermal steam unit is used for station start-up from cold conditions. The unit is completely self-contained, requiring neither an external power source nor cooling water. Power is generated from a single Curtis stage fed with separated steam; the lubricating oil is air-cooled. All mechanical, electrical, and control elements are mounted on a single platform. The technical particulars may be found in Table 1.

The two single-flash main power units are essentially identical. A simplified flow diagram is shown in Fig. 3. Each unit employs a 5-stage, double-flow turbine with impulse-reaction blading, mounted in a single housing, and develops 30 MW. Each turbine exhausts to a low-level, direct-contact condenser equipped with a slanted barometric pipe. This arrangement assures a negligible pressure loss between the condenser and the turbine exhaust hood, as well as ease of accessibility to condenser auxiliary equipment. The non-condensable gases are drawn from the gas cooler section of the condenser, through a 2-stage, steam ejector with inter- and after-coolers, and discharged to the atmosphere via stacks atop the power house. Two sets of extraction systems are installed on each unit for redundancy. There is no hydrogen sulfide abatement system. The technical specifications may be found in Table 1. The overall resource utilization efficiency (Second Law) for Units 1 and 2 is about 37%. These two units require about 44 kg (97 lbm) of geofluid at the wellhead for each kW·h of electricity generated; the steam rate is 7.6 kg/kW·h (16.8 lbm/kW·h). Five wells supply each unit.

The new dual-pressure unit is rated at 35-MW and is supplied with steam from three additional wells (medium-pressure, MP steam) plus steam flashed from the waste liquid from the wellhead cyclone separators (low-pressure, LP steam). A highly simplified flow diagram is shown in Fig. 4. The broken lines represent hot water from eight wellhead separators. The liquid is flashed in two horizontal flash tanks, producing LP steam (solid lines) which is added to the turbine at the pass-in section. The MP steam (heavy lines) is scrubbed before entering the first stage of the turbine. Provision is made to flash a portion of the MP steam down to the LP section if necessary. Auxiliary steam (thin lines) is used for turbine gland seals, steam ejectors for gland steam, and noncondensable gas removal. The turbine is of the dual-admission, double-flow type in a single housing, with the MP section consisting of 3 stages of essentially impulse blading followed by the LP section of 4 impulse-reaction stages. Table 1 lists the technical specifications for this unit. The geothermal resource utilization efficiency for the third unit will be about 42%, based on design specifications. Since all three units will be interrelated, the overall plant utilization efficiency, for the three units, will be approximately 43%, assuming that the 13 wells which will supply the full plant have the same average conditions of temperature, pressure, and flow

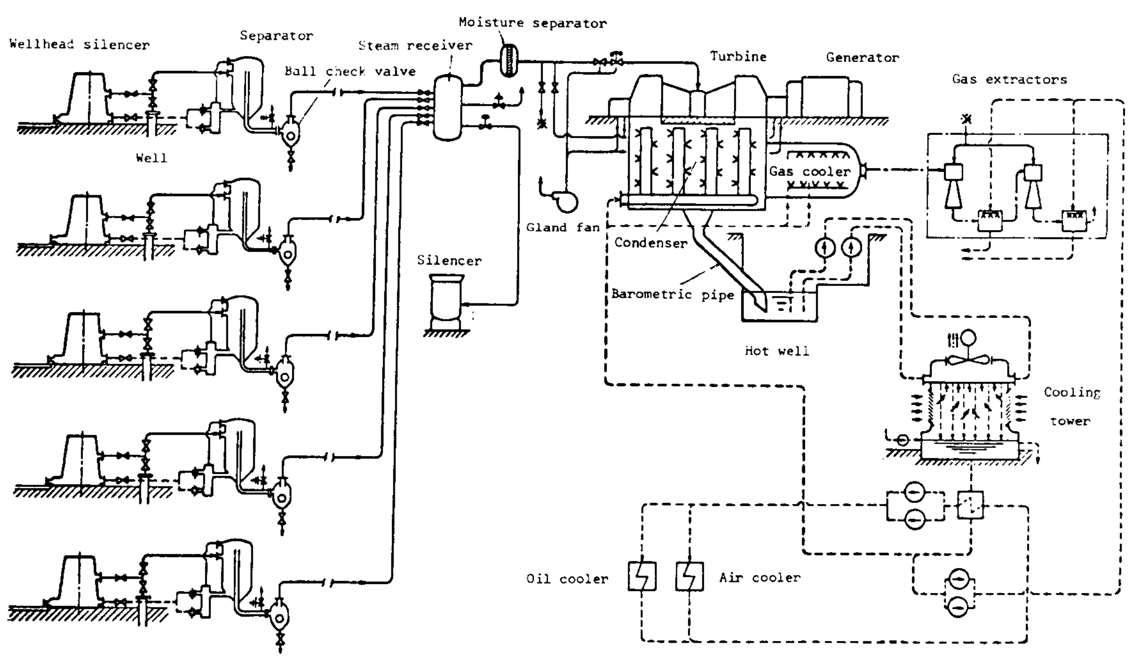

Fig. 3 Flow diagram for Units 1 and 2 (6).

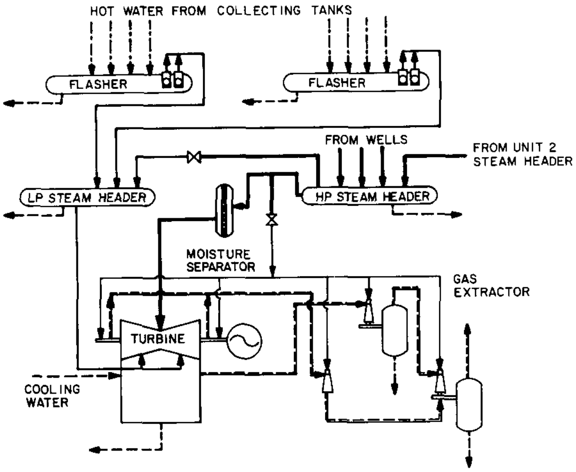

Fig. 4 Flow diagram for Unit 3.

rate as the 10 wells now serving units No. 1 and 2.

Waste liquid handling Two methods are used for the disposal of waste liquid from the plant. One method is reinjection and the other is discharge to the surface, as mentioned earlier.

The temperature of the reinjected liquid from Units 1 and 2 is not less than 150°C (302°F), thus avoiding any problems with silica deposition that might otherwise occur at lower temperatures. Over 13 billion kilograms (3.5 billion gallons) have been returned to the formation since reinjection was begun in 1975. Reinjection is carried out at the pressure of the separators, about 550 kPa (80 lbf/in^2), thus eliminating the need for booster pumps.

Table 1. Technical Specifications for Energy Conversion Systems

	Unit No. 1 and 2	Unit No. 3	Auxiliary Unit
Year of start-up	1975, 1976	1980	1975
Turbine data:			
Type	Single-cylinder, double-flow, impulse, 5 x 2	Single-cylinder, double-flow, dual-admission, impulse-reaction, (3, 4) x 2	Single-cylinder, one Curtis stage, non-condensing, geared
Rated capacity, MW	30, each	35	1.1
Maximum capacity, MW	35, each	40	1.3
Speed, rpm	3600	3600	7129/1800
Main steam pressure, kPa	558.9	548.1	552.9
Secondary steam pressure, kPa	(none)	150.0	(none)
Main steam temperature, °C	156.1	155.3	156.0
Secondary steam temperature, °C	(none)	111.4	(none)
Exhaust pressure, kPa	8.33	8.33	96.2
Main steam flow rate, Mg/h	230, each	171	21
Secondary steam flow rate, Mg/h	(none)	145	(none)
Last-stage blade height, mm	520	565	(n.a.)
Condenser data:			
Type	Low-level, direct-contact type with slanted barometric pipe		(none)
Cooling water temperature, °C	27.0	27.0	-
Outlet water temperature, °C	40.3	40.3	-
Cooling water flow rate, Gg/h	8.65	12.26	-
Gas extractor data:			
Type	Two-stage, steam jet ejector with inter- and after-condenser		(none)
Suction pressure	7.84 kPa	(n.a.)	-
Gas capacity	11,700 m^3/h, each	(n.a.)	-
Steam consumption	4.1 Mg/h, each	(n.a.)	-
Cooling tower data:			
Type	Cross-flow, mechanical induced-draft with vertical axial fans		(none)
Number of cells	5, each	5	-
Design wet-bulb temp.	22°C	22 °C	-
Fan motor power	80 kW/fan	80 kW/fan	-

A portion of the liquid intended for the discharge channel passes first through one of two labyrinth retention tanks which provide 50-60 minutes of hold-up. It has been demonstrated that the settling tank is an effective means of converting monomer silica into polymer silica. This effect stabilizes the silica in solution and eliminates silica deposition in the surface channel. Periodic maintenance of the hold-up tanks is required to remove scale from the walls, but this is a relatively easy task. Surface discharge is a temporary practice; eventually all waste liquid will be reinjected.

Hydrogen sulfide emissions Hydrogen sulfide is emitted at the stack along with the other noncondensable gases. Roughly 95 kg/h (209 lbm/h) or 1580 g/MW·h (3.5 lbm/MW·h) is discharged from the first two units. There are no emissions controls installed on the plant. The concentration of hydrogen sulfide is 1-4 ppm at the boundary of the plant site.

Operating experience The operation of the Ahuachapan plant has been highly successful; the plant forms a vital link in the electricity supply system of El Salvador. Table 2 gives the total generation, capacity factor, and percentage of total electricity in El Salvador contributed by the first two units of the Ahuachapan plant. The geothermal plant has been essentially free of major breakdowns. In 1977 the availability factor was 95% based on forced outages. This factor is reduced to 84% when scheduled outages for maintenance are included. A complete overhaul of each power unit is carried out once every two years. Each inspection takes about one month. Wellhead equipment is thoroughly inspected and cleaned at least once each year. One month is required to service all the wells. There has been no plugging of production or reinjection wells. It has been demonstrated that the reservoir pressure can be controlled and maintained through proper reinjection of waste liquid. Reinjection wells have been sited along the periphery of the field and downstream of the assumed recharge flow in the aquifer. The lack of subsidence may also be related to reinjection, although the field should not be subject to significant subsidence because of the hardness of the andesitic formation.

Table 2. Generating experience at Ahuachapan

	Electrical generation MW·h	Capacity factor %	Pct. of total generation %
1975	72,331	47	11.8
1976	279,800	67	25.4
1977	400,051	76	32.3

Future developments The Ahuachapan power plant has reached its full capacity. Moreover, the experience at Ahuachapan has shown that a liquid-dominated resource of moderate salinity (18,400 ppm) and relatively high temperature (230°C, 445°F) can provide electricity in an economical and reliable manner. Encouraged by their success at Ahuachapan, the engineers and scientists of C.E.L. are intensively investigating several other promising geothermal areas in El Salvador. These include Berlin (100 MW, est.), Chinameca (100 MW, est.), San Vicente (100 MW, est,) and Chipilapa (50 MW, est.). The Berlin area is particularly exciting. The reservoir temperature is about 300°C (572°F) and already three wells have been successfully completed. The plan is to build a 50-MW flash-steam plant at the site by 1985. The unit will likely be of the "double-flash" type.

It is clear that El Salvador is intent on maintaining its leadership role among the Central American countries in the exploitation of its indigenous geothermal energy resources.

Acknowledgements Most of the data reported in this article was obtained during a 3-day visit to C.E.L. headquarters and the Ahuachapan plant during June 1978. The most recent material was obtained in May 1980. A special debt of gratitude is owed Dr. Ing. G. Cuellar, Superintendent of Geothermal Studies, and Ing. R. Caceres, both of C.E.L., for their cooperation. The original study was funded by the U.S. Dept. of Energy, Div. of Geothermal Energy under Contract EY-76-S-02-4051.A001, C.B. McFarland, Chief, Hydrothermal Technology, to Brown University, J. Kestin, Principal Investigator.

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Mexico, with a 60 million population has an extension of almost 2 million square kilometers. A large number of volcanoes and hydrothermal manifestations are found in the area, particularly along the Pacific Coast.

The electricity needs of this country require its installed capacity to be doubled every eight-and-a-half years. Although its main energy source is the hydrocarbons, new sources of energy are being investigated and developed. In 1973, at Cerro Prieto, a 75 MW plant was inaugurated utilizing geothermal steam, initiating in this way commercial exploitation of this energy. From there on an uninterrupted program of exploration and development has been followed, along and across the country.

Probably the region with the highest potential of geothermal energy is the New-volcanic Belt, a zone 300 kilometers wide which crosses the country from the Pacific Coast to the Gulf of Mexico Coast. In this zone, the geothermal fields of Los Azufres, Los Negritos, Ixtlan de los Hervores, La Primavera and San Marcos are located.

Sixteen wells have been drilled at Los Azufres, 14 good producers with an average temperature of 275°C. An area of 385 square kilometers is estimated can be exploited for steam production. By 1981, it is expected to have four wellhead turbogenerators rated 6 MW each.

Two geothermal wells are now being drilled at La Primavera, with very good results. Temperatures of 275°C have been found at a depth of 800 m in the first well of the Rio Caliente module. The first two wells are now being drilled at Los Humeros geothermal zone.

To date, 80 wells have been drilled at Cerro Prieto. In the last group of wells the producing stratum was found at a depth between 2000 and 3000 m. The temperature of this stratum is about 340°C, and each well has an average output of 200 tons per hour.

Research is now being conducted to solve the problems encountered of casing corrosion, and for the development of better cementing materials and improved cementing techniques, since the results obtained have not been entirely satisfactory, being the life of the geothermal wells shortened, increasing the cost of power generation.

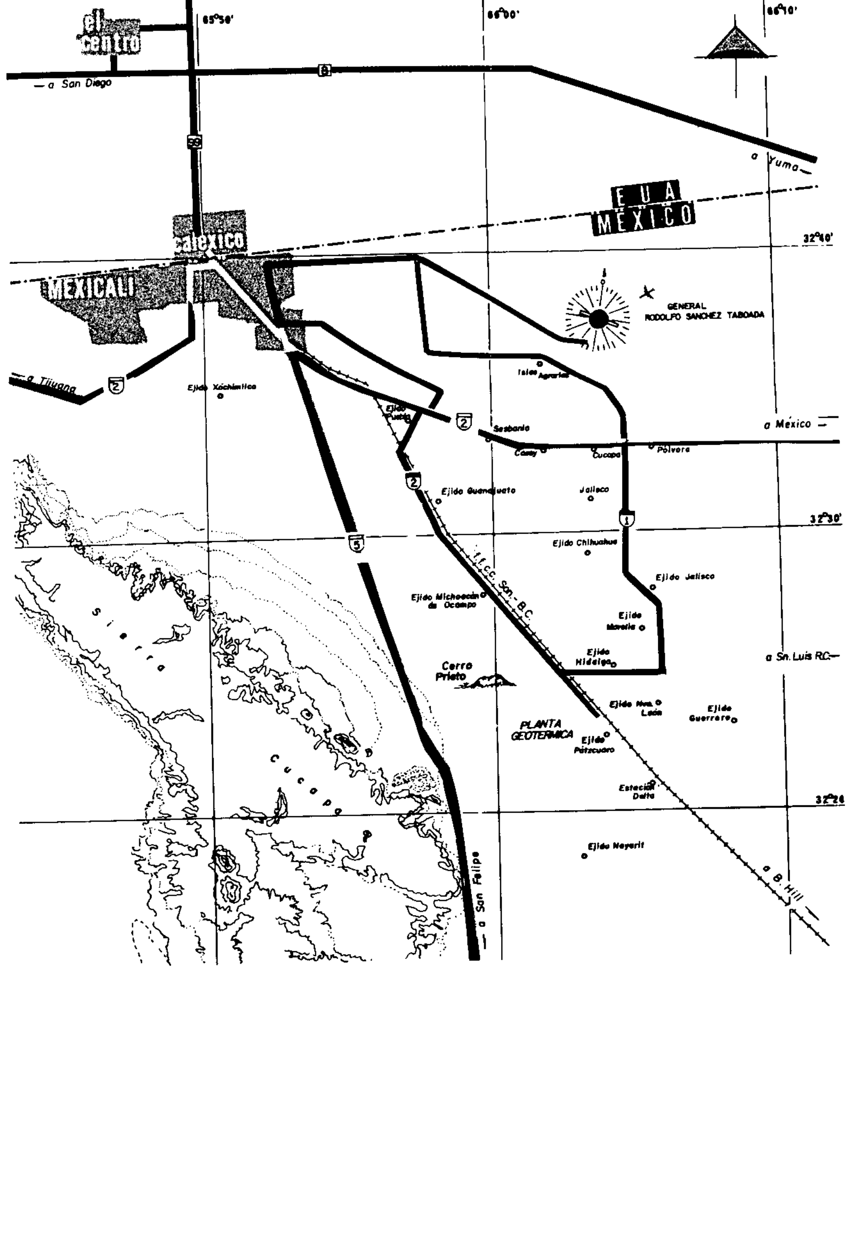
Since its inauguration in 1973, Cerro Prieto has been generating electricity continuously, with increasing annual plant factors, better than 90 percent in the last three years.

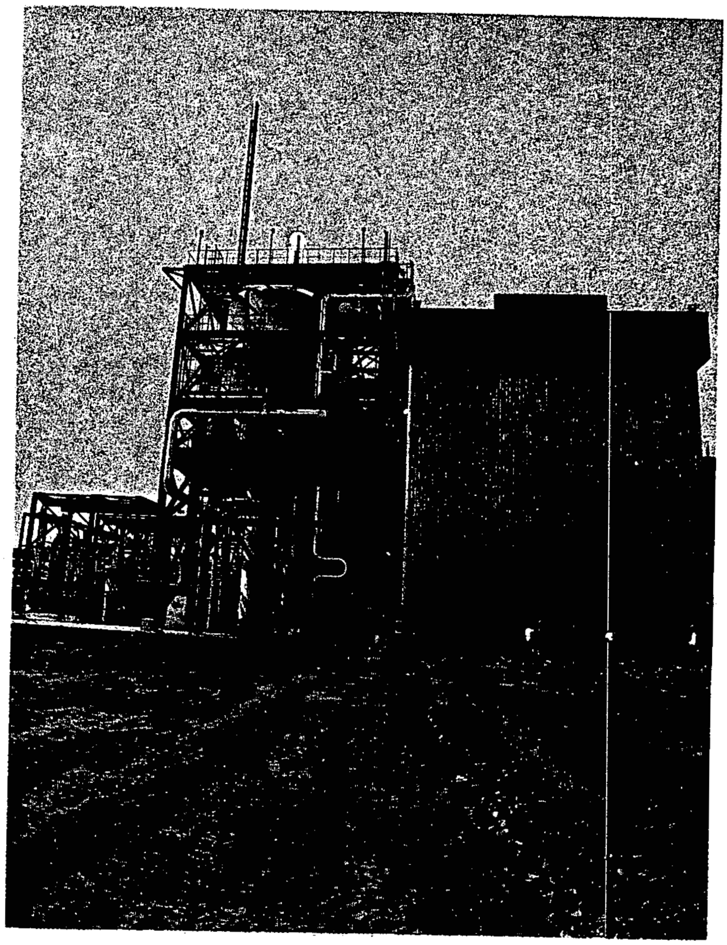
As of this date, the installed capacity at Cerro Prieto is 150 MW. The installation of a fifth unit of 30 MW is now underway. This unit will utilize low pressure steam flashed from the separated water, now being discarded from units 1 to 4. A flashing plant is currently being installed for this purpose. This means a 20 percent increase without drilling more wells.

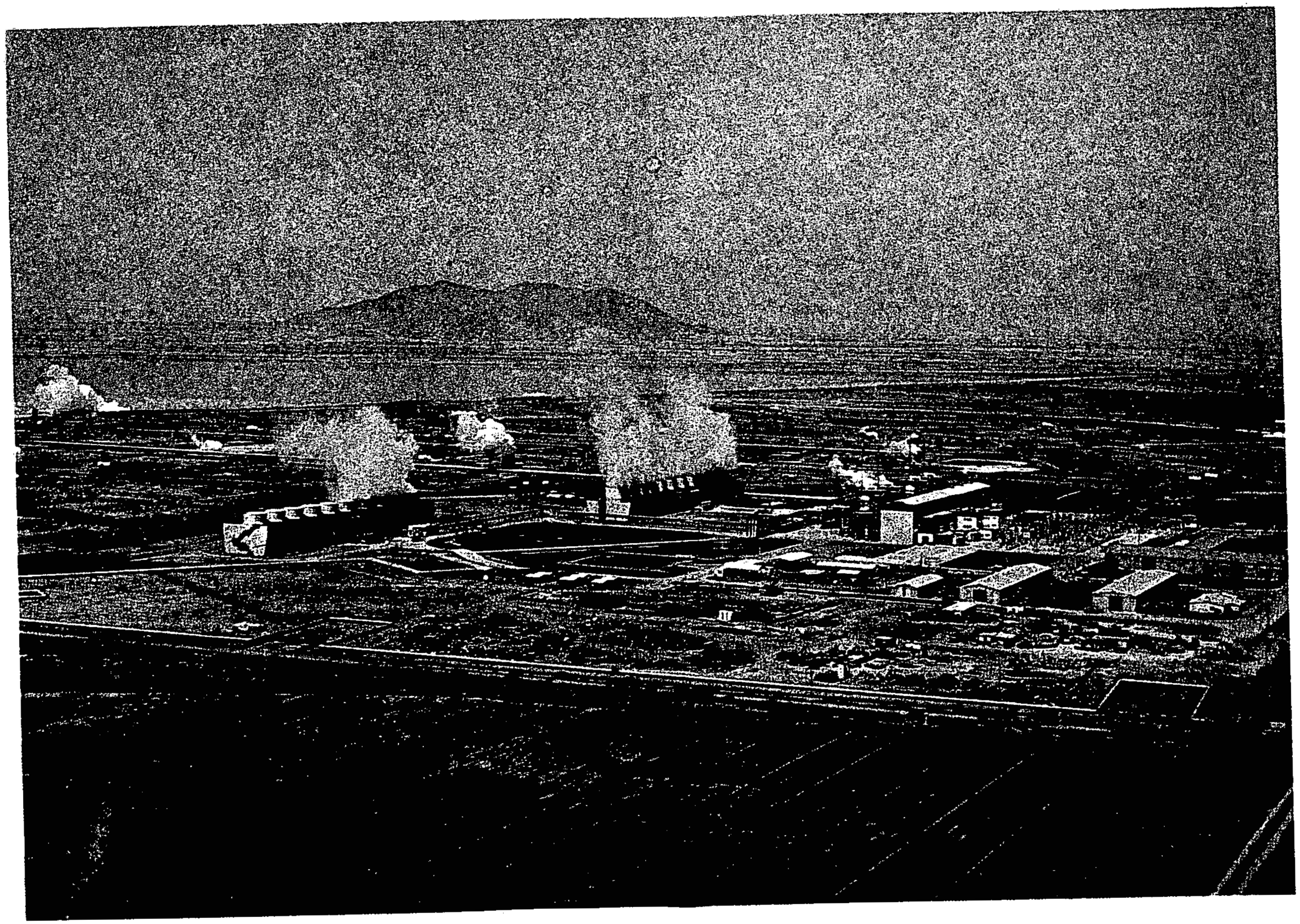
Future plans are the construction of two more plants of 200 MW each, for a total of 620 MW for May 1983. These units will be operating at slightly higher pressures than the existing ones.

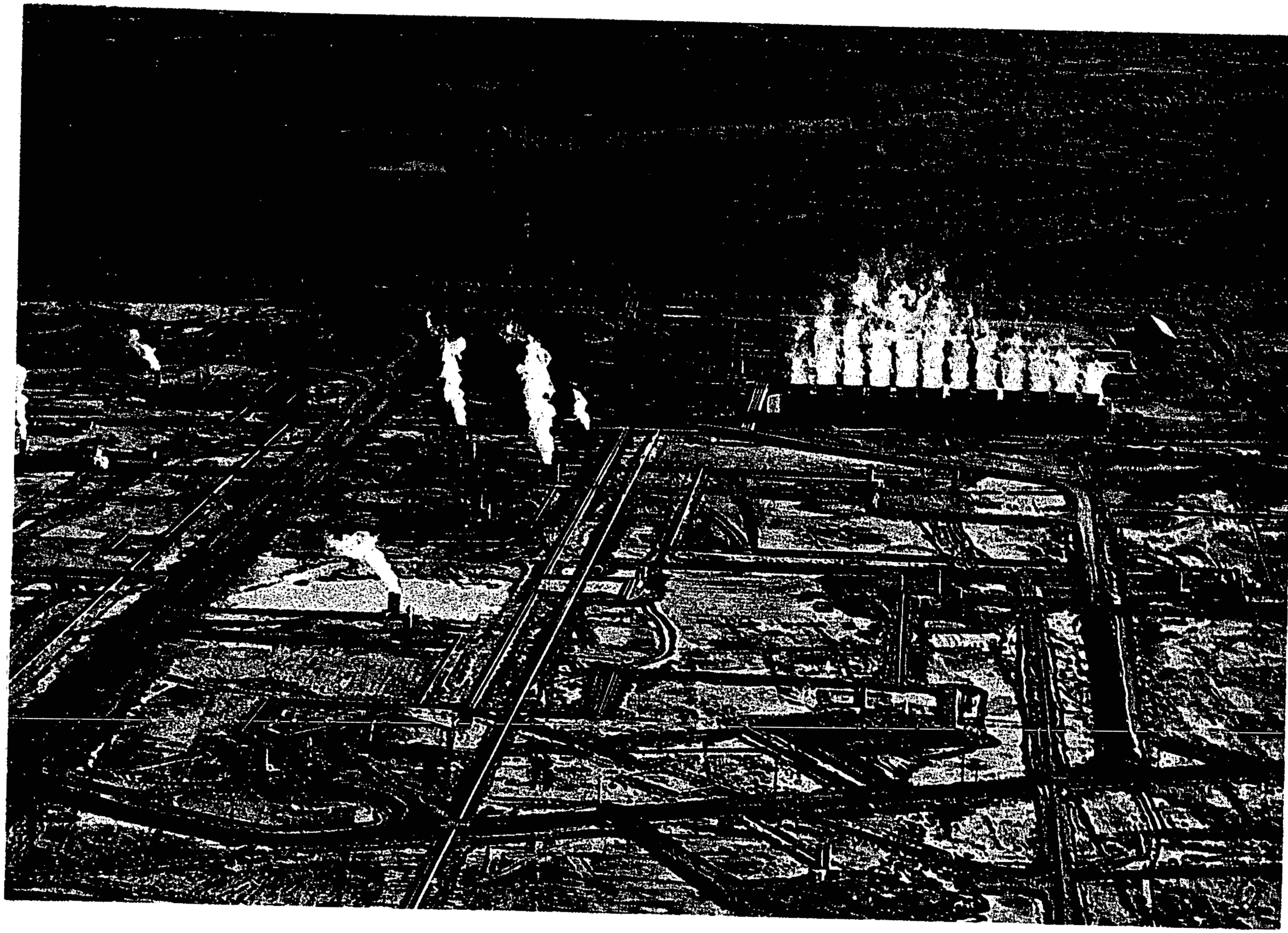
It is estimated that a total capacity of 40,000 MW could be installed by the year 2000, using steam obtained from the known geothermal areas of Mexico.

PRINCIPALES VIAS DE COMUNICACION AL CAMPO GEOTERMICO DE CERRO PRIETO









GEOTHERMAL POWER DEVELOPMENT IN THE PHILIPPINES

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Abstract

The generation of electric power to meet the needs of industrial growth and dispersal in the Philippines is aimed at attaining self-reliance through availment of indigenous energy resources. The Philippines by virtue of her position in the high-heat flow region has in abundance a number of exploitable geothermal fields located all over the country. Results indicate that the geothermal areas of the Philippines presently in various stages of exploration and development are of such magnitude that they can be relied on to meet a significant portion of the country's power need.

Large scale geothermal energy for electric power generation was put into operation last year with the inauguration of two 55-MW geothermal generating units at Tiwi, Albay in Southern Luzon. 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 1979 alone, therefore, 220-MW of generating capacity was added to the power supply coming from geothermal energy. This year a total of 220-MW power is programmed for both areas. This will bring to 443-MW of installed generating capacity from geothermal energy with 3-MW contributed by the Tongonan Geothermal pilot plant in Tongonan, Leyte, Central Philippines in operation since July 1977.

Financial consideration of Philippine experience showed that electric power derived from geothermal energy is competitive with other sources of energy and is a viable source of baseload electric power. Findings have proven the technical and economic acceptability of geothermal energy resources development.

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 eight fields by 1989 by adding five more fields to the currently developed and producing geothermal areas.

Introduction

In view of the current energy crisis that grips many countries of the world today, attention has been focused on the development and utilization of non-fossil and alternate indigenous energy resources. One of these promising resources of indigenous energy which the Philippines has in abundance is the island arc related geothermal energy (Fig. 1). The Philippines by virtue of her position in the high-heat flow region that characterizes the orogenic zone of oceanic to oceanic convergent plate boundaries of the Western Pacific, has a number of commercial and promising geothermal fields scattered over the length of the archipelago. Consequently, the country has embarked on massive geothermal development program that is now paying off with the operation of 165-MW power plant in Tiwi, Albay, 110-MW power plant in Bay, Laguna and 3-MW power pilot plant in Tongonan, Ormoc, Leyte. This will be followed by additional units in the same area, others in the Palimpinon-Dauin fields of Southern Negros, Mambucal field of Northern Negros, and Manito field in Albay. By the end of this year the total geothermal generating capability of the Philippines is 446-MW making her the second largest user of geothermal energy in the world. (Table 1)

Geothermal energy in a broad sense is the heat from the earth as manifested in several forms as hot intrusive rocks, volcanoes, geothermal reservoirs, and geopressured rocks. Of these only the geothermal reservoirs associated with recent hot intrusive rocks and volcanism have thus far been harnessed for electrical power generation.

High temperature geothermal energy has two forms. Dry steam field (vapor dominated

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system) exemplified by Lardarello geothermal fields of Italy and the Geysers of Western United States are easily exploited with conventional technologies. With the pioneering research done by New Zealand in hot-water system, exemplified by their Wairakei and Broaldland fields, utilization of this geothermal field is now an accepted reality. This is the type of geothermal system found in the Philippines.

STATUS OF GEOTHERMAL PROJECT DEVELOPMENT

At present, there are eight geothermal fields in the country in advanced stages of exploration and development as shown in Fig. 2. The priority areas for exploration and development were determined largely on the strength of the surface thermal manifestationsas the initial basis. This is but a practical rationale borne out by the fact that the hot springs, hot grounds and other related phenomena are positive indications of a concealed source of geothermal fluid, located hopefully at an economically drillable depth.

Tiwi hot spring in Albay Province, one of the most popular spots in Luzon, became an easy first choice, followed by Los Baños in Makiling-Banahaw, Tongonan Valley in Leyte, Palimpinon-Dauin in Southern Negros, Mambucal in Northern Negros, the Manat-Amacan geothermal fields in Davao Province, Daklan-Bokod in Benguet and Manito in Albay.

Tiwi Geothermal Project

The geothermal possibilities of Tiwi in Albay were first to be investigated by the government in 1964 through the Commission on Volcanology with financial assistance from the National Science Development Board. The area is presently being developed by the National Power Corporation. Drilling of production wells by the Philippine Geothermal, Inc., a subsidiary of Union Oil Company of California, for the National Power Corporation is going on smoothly and more than fifty wells have been completed so far. By the end of the year, the combined capacity of the project will be two hundred twenty megawatts while the proven capacity of the area is five hundred fifty five megawatts.

Makiling-Banahaw Project

The region hugging the aprons of Mt. Makiling and Mt. Banahaw and the lowland between them studded with diatremes or maars are at present undergoing active development by National Power Corporation with Philippine Geothermal, Inc. carrying out the deep drilling operations. More than fifty-two wells have been drilled to date. Similar to Tiwi the field will have a combined generating capability of two hundred and ten megawatts this year.

Leyte Geothermal Project

The Leyte Geothermal area is undergoing active exploration and development by PNOC-EDC with the assistance of the New Zealand government. Nineteen production wells have been drilled to date. A three megawatt pilot plant is presently in operation in the area since July, 1977. By 1982 the area will have a combined generating capacity of 112.5 megawatts, enough for the envisioned power needs of the proposed copper smelter and the provinces of Leyte and Samar.

Negros Geothermal Projects

The geothermal area of Southern Negros is located at the Palimpinon-Dauin sector of Negros Oriental. Under the New Zealand assistance program PNOC-EDC has completed ten exploratory wells. A three megawatt pilot power plant will be operational by September of this year.

Mambucal prospect of PNOC-EDC is situated at the Northern Sector of Negros Island. Geologic investigation, geochemical studies, magnetic and resistivity surveys and exploration wells indicate sufficiently high temperature at depth and point to favorable underground characteristics. Two intermediate exploration wells have been completed so far.

Davao Geothermal Project

The area of interest has many impressive thermal manifestations clustered in four groups namely Manat, Masara, Amacan, and Maraut. Twenty-five thermal gradients wells drilled at an average depth of one hundred twenty-two meters were sited on the basis of geology, geochemical and geophysical surveys. Results showed a broad thermal anomaly in the area.

Manito Geothermal Project

PNOC-EDC started full scale exploration program at Manito in Albay. Two exploratory wells were drilled on the basis of favorable geological, geochemical, and geophysical surveys. The two exploratory wells drilled along the flow regime confirmed the presence of high temperature geothermal fluids.

Daklan-Bokod Geothermal Area

The area under consideration by the Bureau of Energy Development with the assistance of the Italian government is in Daklan, Bokod, Benguet. Seven exploration gradient wells with average depth of one thousand feet have been drilled so far and preliminary data show impressive geothermal fluids at depth.

GEOTHERMAL IMPLICATIONS OF PHILIPPINE GEOLOGY

From the geologic setting of the Philippines and vulcanism that had occured in the archipelago since Tertiary time with its consequent resulting volcanic rock units, the following general evaluation of their geothermal implications may be considered:

1. The potential geothermal areas of the Philippines will be found in the concave side of the volcanic fronts of plutonic and volcanic rocks of calc-alcalic to alkalic series (Fig. 2, Datuin & Uy, in Press);

2. The vicinity of non-active volcanoes of Pliocene or Quarternary age like Malinao (Tiwi geothermal field), Makiling and Banahaw (Mak-Ban geothermal field), Cuernos de Negros (Southern Negros geothermal fields), and many others that dot the archipelago from north to south offer the most promising areas for geothermal exploration and development;

3. The crystalline rocks and their derivatives that will predominate at the geothermal areas will most likely be sodic to intermediate in composition and will in general be intercalated with relatively thin normal clastic sedimentaries and/or reef limestone lenses;

4. The reservoir rocks will be found either in hydrothermally altered pyroclastic and clastic sedimentary beds, highly fractured formations, and andesitic or dacitic pyroclastic flows;

5. Lava flows will invariably provide capping rock over the reservoir rocks. Geophysically, therefore, many geothermal reservoir areas will be characterized by resistivity lows underneath high resistivity values that are correlatable to relative magnetic highs;

6. Arcuate faulting brought about by the amassed weight of volcanic edifice, and/or recession of magmatic materials or pressure will provide to some degree the structural control that may delineate the reservoir areas. In some areas, as in geothermal areas located close to the Philippine fault zone (Leyte geothermal field), structural control may be provided by the zone itself or secondary faults formed as a consequence of major fault displacements;

7. Except where the geothermal area is the result of convective heat transfer from magma chamber itself as in the case with volcanic craters, the geothermal area will most likely be the result of ground water circulating in fractured formations heated by conduction from the magma chamber;

8. Considering the thickness of Tertiary and recent volcanics in studied areas of the archipelago, and based on thermodynamics considerations, the productive zones will in general be between 3500-6000 feet. Minor steam horizons may exist at much shallower deposits, however; and

9. The rate of recharge of geothermal fields in the Philippines may be expected to be high considering the Island's high annual rainfall. This condition would insure a longer productive life of the field.

COST OF GEOTHERMAL POWER DEVELOPMENT

Recent evaluation and quantitative studies showed geothermal energy for power generation is a viable source of baseload electric power. The utilization of available natural steam is, therefore, considered as major alternative for providing incremental generating capacity as well as for replacing oil thermal plants which have become expensive to operate.

TABLE NO. 3

Comparative Generating Cost of Different Power Plants*

	Cost/KWh
Hydro (Pulangui IV)	7.18
Coal fired Local	21.11
Imported	29.59
Geothermal Manito	30.94
Hi-Viscosity Thermal Plant	30.14
Bunker C Oil Thermal Plant	39.51
Diesel Thermal Plant	49.26
Nuclear Plant	31.25

*Summarized from IPAD, NPC, February 8, 1980

GEOTHERMAL POWER PROGRAM

In order to maximize the benefits from the utilization of indigenous geothermal resources, the government's ten year program for geothermal exploration and development aims at 14018.5MW of generating capability by the year 1989. (Table Nos. 2 and 3). The program includes the development of eight fields by 1989 adding five more fields to the currently developed and producing fields at Tiwi, Makiling-Banahaw, and Tongonan Valley. The five fields targeted for development are Daklan-Bokod, Benguet; Manito, Albay; Mambukal-Mandalagan, Negros Occidental; Palimpinon-Dauin, Negros Oriental; and Manat-Masara, Davao del Norte. (Tables 4 and 5)

TABLE NO. 4

Geothermal Generation Expansion Program

MW	LOCALITY
1979 - 223MW existing	Tiwi, Makban, Tongonan
1980 - 223MW	Tiwi, Makban, Palimpinon
1981 -	
1982 - 335.0MW	Tiwi, Tongonan, Palimpinon
1983 -	
1984 - 37.5MW	Tongonan
1985 - 220MW	Tiwi, Makban
1986 - 37.5MW	Tongonan
1987 -	
1988 - 110MW	Tiwi, Makban
1989 - 75.0MW	Mambugal, Tongonan
1990 - 147.5MW	Tiwi, Manito, Makban, Mambucal

The steam availability is expected to be 1,975MW by 1989 assuming the present success ratio in geothermal production drilling.

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 fields of probable geothermal importance and little known thermal spots that could have geothermal significance.

Lindal enumerated the nonelectrical uses of geothermal steam as shown in Table Nos. 6 and 7. The utilization of geothermal energy in any of these forms, however, is not without its share of technological problems. Researches along the suggested topics should be encouraged.

In the Philippines geothermal energy is presently used for salt-making and grain-drying. Projects on the utilization of thermal field for fish canning, refrigeration and air-conditioning are also being studied.

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 and in some cases specific only to some steam wells of a particular area.

Hardware 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.

Benefits of Geothermal Development

The benefits that can be reaped from the development of the country's geothermal resources in this context are varied and far reaching.

The use of geothermal energy as a substitute will reduce the amount of oil importation for power generation and thus a corresponding decrease in the drain of the country's dollar reserves. It is estimated that if the target of 1975 MW by 1989 of geothermal power capacity is attained, it would mean an annual savings of about $5.235M in oil importation at $30.00/barrel of oil and at 90% load factor.

The Philippines may be considered as an industrially developing country. To sustain a planned annual gross national product of 7 to 8 percent, there is need for new and additional industries to establish themselves in the island. Geothermal energy could provide a significant amount of their energy requirements. With cheaper geothermal power available to industry in areas removed from traditional center of industrial development, and with proper incentives, it is hoped these conditions would attract industries to set themselves up in such areas. This certainly will be in consonance with the basic national policy to meet the needs of industrial development and dispersal.

Many areas of the Philippines have yet to enjoy the benefits of electricity. Total electrification of the country is, therefore, another pressing program of the government. Through the National Electrification Administration much is being done toward this end with the establishment of electric cooperatives. However, many of the cooperatives operate small diesel generation plants. Development of geothermal power and the installation of island grids will greatly boost the total electrification program.

It is fortunate that the geothermal areas of the Philippines are fairly well distributed throughout the country. The geothermal field of Leyte when developed, for example, could supply electrical power to the entire provinces of Leyte and Samar, two identified economically depressed areas. Electrification will mean to these provinces upliftment of their economic status through more job opportunities, home industries and increased earnings. For smaller islands where geothermal energy could be tapped, the feasibility of putting up generating units of 100 to 1000KW capacity is under consideration.

Summary

The geothermal potential of the Philippines is being tapped in the desire to attain self-sufficiency in energy through availment of indigenous energy resources. Eight areas, in various stages of exploration and development are being worked simultaneously.

The development of an indigenous energy is anticipated to reduce the drain of the country's dollar reserves, fill the needs for industrial development and dispersal, contribute to the total electrification effort, and uplift certain economically depressed areas of the country.

Truly, it may be said that the presence of large geothermal energy in the islands is indeed providential in the light of the energy crisis that grips the nation today and the urgency of warding it off permanently.

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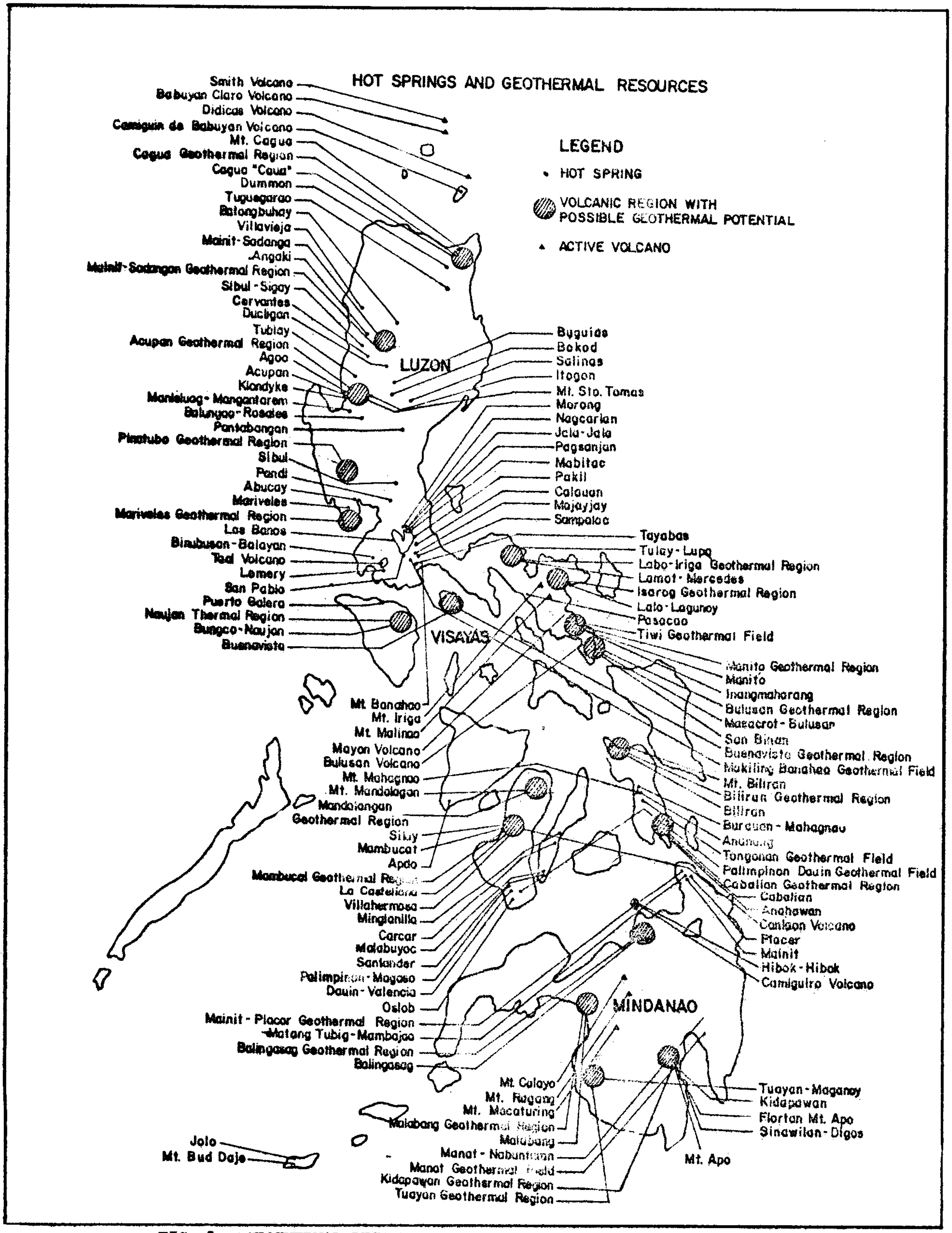

FIG. 1 - GEOTHERMAL RESOURCES OF THE PHILIPPINES

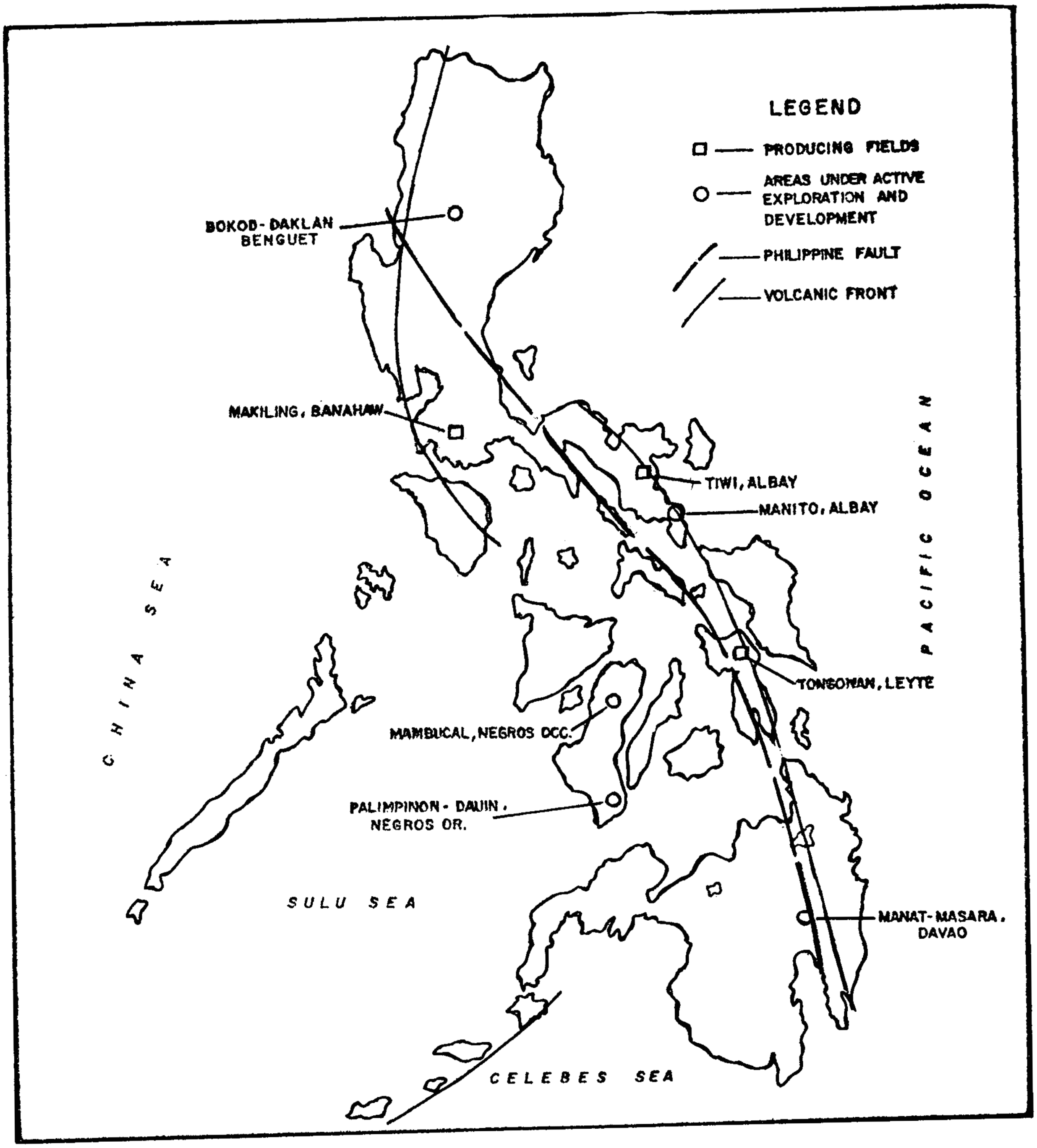

FIG. 2 – GEOTHERMAL AREAS UNDER ADVANCE EXPLORATION AND DEVELOPMENT

TABLE NO. 1

COMPARATIVE GEOTHERMAL ELECTRICAL GENERATING CAPACITY OF THE WORLD IN 1977 AND WHAT IS PLANNED BY 1982

COUNTRY	1977 1/ (MWe)	RANKING	1982 2/ (MWe)	RANKING
UNITED STATES	502	1	1,409	1
ITALY	417.6	2	481.6	3
NEW ZEALAND	202	3	302	4
JAPAN	169	4	244	5
MEXICO	75	5	180	6
EL SALVADOR	60	6	95	7
ICELAND	32.5	7	62.5	8
USSR	5	8	28	12
PHILIPPINES	3	9	548	2
TAIWAN	0.6	10	5.6	15
TURKEY	0.5	11	15	13
NICARAGUA	-	-	35	9
CHILE	-	-	30	10
INDONESIA	-	-	30	11
KENYA	-	-	15	14
TOTAL	1,467.2		3,480.7	

(Source of Information: Dr. Donald E. White, USGS)

1/ Installed Capacity

2/ Definitely committed; with completion dates scheduled up to 1982

TABLE NO. 2

COMPARATIVE COST OF GEOTHERMAL POWER DEVELOPMENT IN THE PHILIPPINES

PROJECT	COST/KW	CAPACITY (MW)	TOTAL COST (MP)	DATE OF 1st ROLL
1. Tiwi Units 1-2 (2 x 55 MW)	5281	110	580.90	#1 12/15/78 #2 5/10/79
Steam Production	2332		256.62	
TOTAL	7613		837.52	
2. Tiwi Units 3-4 (2 x 55 MW)	5527	110	608.01	#3 12/20/79 #4 4/ 8/80
Steam Production	2332		256.62	
TOTAL	7859		864.63	
3. Mak-Ban Units 1-2 (2 x 55MW)	4662	110	512.8	#1 3/30/79 #2 5/30/79
Steam Production	2332		256.62	
TOTAL	6994		769.42	
4. Palimpinon Pilot Units 1-2 (2 x 1.5 MW)	4453	3	13.36	#1 8/80 #2 9/80
Steam Production	2500		7.5	
TOTAL	6953		20.86	
5. Tongonan Units 1-3 (3 x 37.5 MW)	7392	112.5	831.66	#1 5/82 #2 8/82 #3 11/82
Steam Production	3891		437.80	
TOTAL	11283		1269.46	
6. Palimpinon Units 1-3 (3 x 37.5 MW)	6129	112.5	689.55	#1 11/82 #2 2/83 #3 5/83
Steam Production	2651		298.30	
TOTAL	8780		987.85	
7. Tiwi Units 5-6 (2 x 55 MW)	4531	110	498.41	#5 4/82 #6 7/82
Steam Production	2522		277.50	
TOTAL	7053	775.91		
8. Mak-Ban Units 3-4	5296	110	582.59	#3 5/80 #4 8/80
Steam Production	2332		256.62	
TOTAL	7628		839.21	

($1 = ₱7.50)

TABLE NO. 5

Geothermal Power Development Program

Year	Cumulative No. of Fields	No. of Wells	Cumulative Geothermal Steam Availability (MW)	Cumulative Probable Geothermal Reserves (MW)
1979 (existing)	3	95	560	10
1980	4	60	805	40
1981	4	68	1,055	110
1982	4	76	1,315	180
1983	5	84	1,565	240
1984	6	80	1,820	300
1985	7	51	1,975	350
1986	7	36	1,975	470
1987	8	34	1,975	580
1988	8	34	1,975	700
1989	8	29	1,975	820
TOTAL	8	647	1,975	820

TABLE NO. 6

Possible Non-Electrical Uses of Saturated Steam

Saturated Steam

°C	
200	
190	
180	Evaporation of highly concentrated solutionn Refrigeration by ammonia absorption Digestion in paper pulp, kraft
170	Heavy water via hydrogen suphide process Drying diatomaceous earth
160	Drying fish meal Drying timber
150	Alumina via Bayer's process
140	Drying farm products at high rates Food canning
130	Evaporation in sugar refining
120	Fresh water by distillation Most multiple-effect evaporations, concentration of saline solution
110	Drying and curing light aggregate cement slabs
100	Drying organic materials, seaweeds, grass, vegetables, etc. Washing and drying wool

Conventional power production

Required temperatures (approximate) of geothermal fluids for various applications

A - Saturated Steam

Source: B. Lindal, "Industrial and Other Applications of Geothermal Energy"

TABLE NO. 7

Possible Non-Electrical Uses of Hot Water

Hot Water

120	Fresh water by distillation Most multiple-effect evaporation, concentrations of saline solution
110	Drying and curing light aggregate cement slabs
100	Drying organic materials, seaweeds, grass, vegetables, etc. Washing and drying wool
90	Drying stock fish Intense de-icing operations
80	Space heating Greenhouses by space heating
70	Refrigeration (lower temperature limit)
60	Animal husbandry Greenhouses by combined space and hotbed heating
50	Mushroom growing Balneological baths
40	Soil warming
30	Swimming pools, biodegration, fermentations Warm water for year-round mining in cold climates De-icing
20	Fish matching and farming

Required temperatures (approximate) of geothermal fluids for various applications.

B - Hot water

Source: B. Lindal, "Industrial and Other Applications of Geothermal Energy"

WAIRAKEI - THE FIRST TWENTY YEARS

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General Details The Wairakei Geothermal Power Complex is situated five kilometres north of Lake Taupo in the North Island of New Zealand. The Wairakei system consists basically of a highly permeable hot water aquifer contained within almost impermeable boundaries.

Steam is produced from the hot fluid in a three-stage flash process. Initially the first stage produced steam at 13.8 bar g (200 psig) but due to declining field pressure this has been progressively reduced to 8.3 bar g (120 psig) by mid-1980. The second stage produces steam at 5.5 bar g (80 psig). In 1972 the third stage flashing facilities were installed to utilise the otherwise waste saturated water from the second stage. This produces steam at 1.72 bar g (25 psig).

The first machine was synchronised to the national grid on 15 November 1958 and the last machine in October 1964.

Development of the power complex was in two stages and has a total installed capacity of 192 MWe. The final arrangement of equipment is shown in Figure la. The unusual complexity of small machines in the Stage I development is a result of the initial concept containing a heavy water distillation plant. This plant, however, was stopped early in the project, but not before manufacturing contracts had been let. At this stage it was considered too late to redesign the whole project, so, to take the place of the distillation plant, additional turbogenerators were installed. The Stage II development added 3 x 30 MWe mixed pressure machines. Turbine stop valve design pressures are:

High pressure (HP)
12.4 bar 6 (180 psig)

Intermediate and mixed pressure (IP) and (MP)
3.45 bar g (50 psig)

Low pressure (LP)
0.03 bar g (0.5 psig)

The centre of steam production is about two kilometres from the station. At present there are, 60 production wells connected to the steam transmission system; 26 of these are classed as high pressure and 34 as intermediate pressure producers. In addition, 7 multiple flash plants are strategically located within the field to enable intermediate pressure saturated water to be flashed to 1.72 bar g (25 psig). Figure 1b shows diagrammatic layout of the steamfield plant. Drilled depths for the wells range from 200 m (650 ft) to 1,200 m (4000 ft). Production casing sizes are generally 200 mm (8 in) with 150 mm (6 in) slotted casing occupying the lower 120 m (400 ft) to 600 m (1950 ft) production levels.

Transmission of steam to the power station is by steam mains at present arranged as follows:

High pressure
2 x 760 mm dia (30 in); 1 x 502 mm dia (20 in)

Intermediate pressure
1 x 760 mm dia (30 in); 4 x 502 mm dia (20 in); and 1 x 460 mm dia (18 in)

Low pressure
1 x 1220 mm dia (48 in)

Waste water from the field, currently running at 1.12 cumecs is discharged via open drain culverts to the Wairakei stream and hence into the nearby Waikato River. Water from this river is also used to provide cooling water for the direct contact condensers.

Wairakei is located approximately 305 m (1200 ft) above sea level and the normal atmospheric pressure at the station is 0.97 bar.

Managing Policies In the mid-1960's it was recognised that drilling additional wells to maintain or increase output at Wairakei would only accelerate the field rundown. Consequently it was decided to hold mass output at the then production level of around 65 million tonnes annually.

In view of this decision New Zealand Electricity management policies resolved into the following:

(i) to ensure that the IP, MP and LP machines are fully supplied with steam at design pressure;

(ii) to sacrifice HP machine output as necessary to maintain IP, MP and LP machine output;

(iii) to obtain more efficient use of the total energy discharged from the field.

Maintenance Strategies The objectives of maintenance of this type of plant are similar to those for other thermal plants, i.e.

(i) to ensure the safety of the plant, its personnel and the general public;

(ii) to comply with the statutory requirements which apply to the plant and its personnel;

(iii) to ensure a high degree of plant availability so that the investment in the plant can be returned;

(iv) to maintain or improve the economy of operation of the plant.

Geothermal work is relatively new on an extensive scale and developments in materials also contribute to keeping the art in a state of change. The outstanding feature of geothermal work is the way it calls on a very wide range of specialists. New Zealand Electricity experience has been that access was needed to the following scientific disciplines:

Reservoir engineering
Corrosion chemistry
Analytical chemistry
Gas Analysis chemistry
Metallurgy
Nondestructive testing of materials
Nuclear sciences

These services are required on a more or less regular on-call basis and they have been provided by the Department of Scientific and Industrial Research. The input amounts to some six to nine man-years. New Zealand Electricity operates the Wairakei steamfield but draws on the drilling, civil and mechanical engineering expertise of the Ministry of Works and Development for all "down hole" work, field measurements, pipeline and separating equipment construction, and maintenance of some drains and roads, etc.

The New Zealand Electricity general policy is to seek the best advice available and follow it subject to economic analysis. Very simple criteria, intelligently applied are sufficient for decision making with regard to expenditure on maintenance or improvements. The standard techniques derived from Discounted Cash Flow analyses are capable of resolving most of the problems on expenditure, provided the following data are available:

(i) the rate of return required of capital expenditure;

(ii) the value of incremental production;

(iii) a risk assessment of the chances of success if this applies.

In the largely hydro system of New Zealand Electricity the value of incremental production can be as low as $10,000 per GWh. In steamfield decision making account must be taken of the fact that the production of wells normally declines with time. Consequently the decline in production must be taken into account by adjustment to the required rate of return.

Operating Costs Wairakei operating costs are about $3 million per year and interest charges on the development capital are about $8 million per year. The capital costs are historic and the development is over 20 years old. With the reservation that these costs do not represent costs of present day investment, Wairakei production costs were about 1.1 cents per unit in 1979. The cost of hydro production in the North Island with varying ages of investment average about 1.27 cents per unit. With present day investment costs and increased environmental considerations geothermal energy costs would be considerably higher.

Wairakei operating costs include an annual charge to the D.S.I.R. for their scientific services and work carried out by the Ministry of Works and Development is charged at cost.

Summary of Production History Since exploitation of the Wairakei geothermal resource first began the total mass withdrawal from the field to the end of 1979 has been approximately 1,200,000,000 tonnes and the total electrical energy produced has been 20,836 Gwh.

The main reactions of the reservoir to exploitation have been:

(i) after an initial rapid fall, the "at depth" pressure of the field is now approaching a relatively stable value;

(ii) despite the near stabilisation of the "at depth" field pressure, well outputs have continued to decline;

(iii) after showing an initial increase, the apparent enthalpy of the fluid is decreasing slowly (approximately 3.5 kJ/kg/yr (1.5 BTU/lb/yr);

(iv) subsidence of the ground surface has been extensive over a considerable area adjacent to the main production zone.

Table I gives the production history of the field and plant since the beginning of commercial exploitation.

The main feature of the table is the consistent annual output from Wairakei in the face of an apparently declining resource. This consistency has been achieved by more efficient utilisation of the total energy discharged from the field.

TABLE I

SUMMARY OF WAIRAKEI GEOTHERMAL POWER PROJECT
PRODUCTION DATA FROM 1959 TO 1979

Year	Reservoir at Depth Pressure Bar g (1)	Mass Withdrawal Tonne x 10^6	Apparent Enthalpy kJ/kg	Energy GWh(e)	Peak Power MW(e)	Turbo-Alternator	
						Load Factor %	Availability Factor %
1959	58.6	37.34		6.4			
1960	54.5	47.84		169	50.6	37.9	NA
1961	52.8	42.25	1095.5	384	64.0	68.5	NA
1962	50.3	51.80	1100.2	491	65.6	85.5	NA
1963	46.9	73.40	1097.9	761	131.1	66.3	NA
1964	44.1	70.80	1135.1	1004	148.4	77.0	NA
1965	42.8	65.80	1151.4	1194	173.0	78.8	NA
1966	42.1	64.30	1139.7	1255	166.0	86.33	NA
1967	41.4	59.60	1132.8	1268	170.8	84.72	NA
1968	40.7	47.70	1146.7	1058	166.8	72.18	79.4
1969	39.9	55.80	1131.1	1207	165.7	83.12	90.3
1970	39.0	56.00	1131.1	1243	159.8	88.80	90.3
1971	38.5	54.30	1103.9	1185	153.4	88.20	90.2
1972	38.1	52.50	1109.5	1174	149.3	89.55	89.8
1973	37.8	48.20	1115.8	1175	147.7	90.80	92.5
1974	37.7	47.00	1112.8	1162	148.6	89.26	87.9
1975	37.5	46.10	1109.7	1249	159	89.64	88.73
1976	37.4	47.60	1090.7	1272	158.1	91.60	90.0
1977	37.2	46.50	1088.8	1232	152.9	92.02	88.5
1978	37.1	46.30	1093.0	1158	145.7	89.62	70.95
1979	37.0	46.2(2)	1086.7(2)	1190	145.7	92.92	86.2

1. Reservoir pressure is that obtained by a regression analysis of the pressure of a selection of wells as measured in the water phase and corrected to a depth of 275 m (900 ft) below sea level.

2. Data not available (NA) figures estimated.

Initially only 4.5 percent of the total energy above 0°C was converted to electricity, compared with 8.5 percent in 1979. This improvement has resulted from extensive use of multiple flash units. However, as nearly all the economically collectable IP water is now being fed to these units, maintenance of the station output will have to depend on alternative means in the future.

Despite the stabilisation of the field "at depth" pressure, output from the wells has continued to decrease. To overcome this declining output it has been necessary to progressively reduce the wellhead pressure on the HP production wells so as to maintain the fluid flow from the wells. Initially the HP wells operated with a wellhead pressure of 13.8 bar g (200 psig); currently this pressure is only 8.3 bar g (120 psig). In consequence the output from the HP machines is greatly reduced, the machines being used essentially as pressure reducing valves. This action, however, has enabled the IP, MP and LP machines to be kept fully loaded.

The reason for the decline in well output is essentially due to the discharge enthalpy approximating the recharge water enthalpy and hence the steam fraction is less.

Figure 2 shows the trend over the last five years in the average net power generation for the three winter months, a period during which every effort is made to have all production wells on line. Neglecting the low values obtained during the 1977/78 winter, a mathematical analysis gives the equation of this curve to be:

$$y = 0.29\,x^2 - 4.714x + 151.4$$

where x = years from 1976; y = station output MWe. This equation is only effective until 1984 but shows that by that time the station output will have fallen to 132 MWe.

Another important point to note from the table is the mechanical reliability of the station. The annual station load factor has consistently been between 85 and 90 percent and the availability factor in excess of 85 percent for nine of the last ten years.

Wairakei has one of the best records for reliability of any power station in New Zealand and is significantly better than any of the thermal stations.

Performance of Steamfield Plant and Materials
In 1975 the need for annual surveys of wellhead and steam transmission pipework changed to biennial inspection, experience having shown that there was no requirement for this equipment to be inspected and overhauled annually.

The choice of mild steel as the main material for all wellhead, flash plant, and steam transmission equipment has proved to be a wise choice, provided oxygen can be excluded from the geothermal fluids. Table II shows principal materials used at Wairakei.

Cyclone Separators Initial erosion problems with the cyclone separators, due to grit and pumice discharged with the fluid being rotated around the bottom of the chamber by the cyclonic action, was simply solved by welding vanes to the bottom surface to trap the well debris.

Wellhead Silencers Following early failures of reinforced concrete stack pipes of wellhead silencers, trials were commenced in 1965 to assess the suitability of timber for silencer stack pipe fabrication. Various timber and preservative treatments were tested. The most successful timber was found to be Radiata pine treated with a 5 percent P.C.P (pentachlorphenol) by weight in Shell industrial oil No. 4. A silencer made in this material remained in service for 11½ years before replacement was considered necessary. All silencer replacements at Wairakei, and for geothermal wells in general, are now being made with this form of treated timber.

Ground Subsidence Withdrawal of fluid from the Wairakei geothermal field has caused extensive ground subsidence in the region (Ref. 1). The maximum subsidence is now about 7.6 m (25 ft) and is continuing at a rate of about 400 mm (1.3 ft) per annum. Fortunately, the area of maximum surface subsidence is very small, However, the total area affected probably approaches 259 sq. km (100 sq. miles) and the volumetric subsidence is estimated to be of the order of 38×10^6 m^3 (50×10^6 cubic yards). Although quite large, neither the vertical movement, which is associated with subsidence, nor the consequential differential settlement (tilt) has so far created any insurmountable difficulties. All problems so far encountered have been caused directly by ground surface strain.

The region of maximum subsidence fortunately occurs outside the production field (see Figure 3).. However, the steam transmission pipes and the main open culvert hot water drain which runs parallel with the steam mains, have been affected by the ground movement and modifications to these structures have been, and will continue to be, necessary.

In the case of the main drain it has been necessary to incorporate sliding joints within the outfall drop structure, which lowers the hot water 25 m (82 ft) in five unequal steps to the discharge point in the Wairakei stream. While working on this drain modification, leakage from a diversion flume caused the drain structure to fail following washout of supporting pumice alluvium. Photographs 1 and 2 show the extent of damage caused. Failure of the drain necessitated an almost total steamfield shutdown for three days until alternative drainage facilities could be organised. This

TABLE II : SCHEDULE OF PRINCIPAL MATERIALS USED
ON WAIRAKEI POWER PROJECT

PLANT ITEM	MATERIAL DETAILS	CHEMICAL COMPOSITION	REMARKS
Well down hole casings	API 5		
Well-head Master Valves	API 6		
Well-head Steam Separators and Water Drums	BS1501-161 Grade B	0.25% C max.; 0.35% Si max.; 0.5% Mn min.	30,250 lb/sq in yield stress
H.P. and I.P. Steam Transmission Pipelines	BS806 Class B	0.13% C; 0.2% Si.; 0.48% Mn	Includes 3 mm Corrosion allowance
L.P. (1220 mm dia) Steam Transmission Pipeline	BS3601 (1962) SFW Grade 26	0.25% C max.; 0.7% Mn max.; 0.05% S max.; .05% Ph. max.	No corrosion allowance
Turbine Casings Inlet	Cast Carbon Steel		31,360 lb/sq. in yield stress
Turbine Casings Exhaust	BS1501-161-B	0.25% C max.; 0.35% Si max.; 0.5% Mn min.	30,250 lb/sq.in yield stress
H.P.: I.P. and L.P. Rotor Forgings	B.E.A.M.A. No.3 grade 3	1% Nickel steel with added chromium	44,800 lb/sq.in yield stress
M.P. Rotor discs	B.E.A.M.A. No.2 grade 3	0.4% C; 1.2% n.; 0.4% Cr.; 0.05% Mo	
M.P. Rotor shaft	B.E.A.M.A. No.3 grade 3	1% nickel steel with added chromium	44,800 lb/sq.in yield stress
Turbine revolving blades	Stainless iron	0.11% C; 0.5% Mn max.; 0.5% Si; 0.6% Ni.; 13% Cr	40,300 lb/sq.in.
Jet condenser shell	BS1501-161 Grade B	0.25% C Max.; 0.35% Si max.; 0.5% Mn min.	Epoxy coated
Main steam field isolating valves	Cast steel body With stainless/steel spindles		

has been the only major unscheduled plant outage in recent years.

The steam mains are affected by the ground movement altering the distance between the pipe anchors. No provision has been made to accommodate this ground movement and at expansion loop anchors it is necessary to periodically cut a small length (0.3 m) out of the pipe down stream of the loop, move the loop to catch up with the ground movement, and then replace the cut out length in the resulting gap in the pipe on the upstream side of the loop.

New smaller collection pipelines are now prestressed to delay the first readjustments because of ground strain.

Silica Deposition Mineral deposition from geothermal water has caused no problems in wellhead equipment or within the steam pipelines, but presents a major cleaning problem in the open and covered hot water drainage system. Silica deposits grow to a thickness of 100 to 140 mm (4 to 6 in) on the floor and walls of the drains in the yearly period between cleanings. Keeping the drainage system clear of these deposits is a major maintenance expense in the operation of the station.

Attempts to interest New Zealand industry in the silica from the drains has not been successful as surface water runoff contaminates the deposits. The only possibility of utilising this waste product would be by extraction from the fluid before discharging into the drain system.

Steam Transmission Line Corrosion Corrosion damage of a severe nature has occurred along the bottom of the two 760 mm dia (30 in) HP steam pipelines. This corrosion was first discovered during the November 1977 steamfield biennial shutdown.

Initially these lines carried steam at 13.8 bar g (200 psig) but this pressure has been progressively reduced to 8.3 bar g (120 psig) with the decline of field pressure. These HP lines are linked at intervals to equalise pressure and flow.

The corrosion is almost entirely concentrated within the "station end" half of the pipelines and is not present in the "bore field" half of the pipes. The lower half of the internal pipe surface is coated with a crystalline deposit of magnetite of up to 3 mm (1/8 in) thickness; located at random intervals within the magnetite deposit area are large shallow corrosion pits, typically 150 to 200 mm (6 to 8 in) across and generally about 3 mm (1/8 in) deep. In one of the lines, however, pits extended more than half way through the 12.7 mm (½ in) wall thickness of the pipe necessitating the replacement of approximately 150 m (500 ft) of this line.

To prolong the operational life of these pipes it has been necessary to turn each of them through 180° over approximately 1000 m (3250 ft) of their length.

The corrosion cells have a bright slightly mat metal appearance, and are not coated with any corrosion products. Their appearance resembles that of metal freely dissolving in acid. The surrounding pipe surface is uncorroded, but is encrusted with the crystalline magnetite deposit. Photographs 3 and 4 show typical HP line corrosion cells.

The cause of the corrosion has been attributed to the flow of nearly neutral condensation products containing dissolved CO_2 and H_2S gases which flow along the bottom of the pipe. This water is largely removed by extraction catchpots located at approximately 120 m (400 ft) intervals along the pipe. These catchpots very effectively scrub all traces of dissolved chemicals carried over from the separators from the line, which results in the purity of the condensate progressively increasing toward the power station. (Ref. 2.) Because of this near neutral pH of the condensate the exposed iron is attacked; this leads to the dissolution of the iron and subsequent deposition of magnetite further down the pipe. (Ref. 3.)

During the investigation into this problem it was noted that no significant corrosion had taken place within the wellhead equipment or in the upfield end of the HP pipelines. This, it was assumed, was due to the presence of soluble chemicals within the water inhibiting corrosion attack. Tests on the condensate discharged from the catchpots along the whole length of the HP pipelines revealed that where the condensate had a high silica content (greater than 10 ppm) no corrosion had occurred. When the silica content fell well below this figure corrosion attack was very pronounced.

A trial is currently being carried out on one of the HP lines in which silica laden well fluid is being injected to see if this will inhibit the corrosion attack in the station end of the pipeline. Hydrogen probe patches, positioned immediately below an active corrosion cell, have been installed for "on line" monitoring of the experiment, previous work having shown (Ref. 4) that the rate of corrosion can be related to the evolution of hydrogen through the pipe wall. Figure 4 shows the encouraging hydrogen probe results obtained when well fluid was injected into the pipeline for a test trial in April/May 1980. The graph shows that immediately after injection commenced, the collection of hydrogen increased, which suggests that corrosion had stopped. On stopping the injection a period of protection is seen to exist before corrosion once again commences with the collection of hydrogen at the pre-injection rate. Injection of well fluid recommensed on 13 May 1980 and an immediate response was obtained from the hydrogen probe.

Well fluid injection will be continued over the winter generation period and the pipeline opened for detailed inspection in October/November 1980. Condensate discharged from the catchpots will be monitored for the desired level of silica residual at the station end of the pipeline. The presence of chlorides, in the well water being injected, involves careful monitoring of steam quality.

Wellhead Steam Flow Meters Steam flow measurements at Wairakei are used essentially for field management purposes. New Zealand Electricity operates the steam field; thus there is no requirement for an accurate measurement of steam output for energy costing purposes.

Steam output from each of the production wells and flash plants is computed daily from flow nozzle and mercury differential pressure meter readings. These meters, however, are now at the end of their economic life, having been in service for over twenty years. It is planned, therefore, to replace these with stainless steel bellows-type differential pressure meters.

Cooler Water Downflows in Wells Recent measurements using a down-hole spinner show that in two nonproductive wells, substantial quantities of 150°C water are flowing downwards in the open hole section of the well and dispersing into the production zone. It is possible that similar activity is occurring in other wells and in natural fissures.

Radioactive tracers have been used to detect this inflow in surrounding producing wells. The full implication of this is still being considered. However, it should be noted that so far it has not been possible to detect any effect on the heat output of the surrounding wells, even though the downflow is in excess of 200 tonne/hour and is known to have been occurring for some years. A workover on one of the downflow wells has successfully stopped the cooler water inflow and the well has been restored to production use at a level comparable to what it was before it stopped producing some years previously.

Power Station Plant The unfortunate effect of the once proposed heavy water distillation plant on the plant of the Stage 1 development is carried on in the heavy maintenance requirements of the complex of small machines and resultant equipment associated with the 'A' station. The three 30 MW machines of 'B' station are maintained for a much lower cost per unit generated.

The turbines and associated air/gas steam ejectors and jet condensers have remained plant items with high maintenance costs. The combination of saturated steam and the presence of hydrogen sulphide gas in the steam require a greater degree of vigilance than on other turbines of the same pressure and temperature. A programme of four-yearly turbo-generator overhauls has been more than justified by the high availability factor for the plant.

Turbo-Generators The turbine blades on all machines at Wairakei were made from 13 percent chromium iron and supplied in the soft (non-martensitic) state with a Brinell Hardness in the range 160-190. In this condition there was considered less risk of stress corrosion cracking in the geothermal steam environment. To prevent erosion of this soft material in the wet end of the turbine, the blade tip speed was restricted to 275 m/sec (900 ft/sec).

During the first few years service the erosion damage on the exhaust end blades was quite marked. However, this damage has progressed very little since (see Photograph 5), and presents no risk to the integrity of the blades on the 30 MW mixed pressure machines. For this reason no dressing of erosion is done. These machines have each accumulated over 130,000 running hours and following a planned overhaul in 1978 the manufacturers representative considered the machine blading good for another seven to ten years service.

During this overhaul the opportunity was taken to completely dismantle the keyed disc rotor (in view of previous failures of this type of rotor construction at the Hinkley Point Power Station in the U.K.) and give it an extensive examination due to hydrogen sulphide being identified as an agent for stress corrosion cracking. No metallurgical defects were discovered.

All nozzles and diaphragms were found to be in good condition, except for severe erosion damage to the upstream face of the outer rim of several diaphragms. This appeared to be due to water droplets shedding from the upstream stage shrouding. Repairs carried out by station staff entailed machining the damage area and welding in a stainless steel erosion plate.

Casing corrosion, to a maximum depth of 1.5 mm (1/16 in) has occurred in patches. The inner casing drains, however, were found severely corroded. See Photograph 6. These drain pipes are now being replaced in stainless steel.

The exhaust end erosion on the 11.2 MW LP machines due to the smaller blade section, did present a threat to the blade integrity at the banding rivet and by fatigue in the blade,and following a number of Stage 1 blade fatigue failures on two machines after 110,000 hours operation, it was decided to completely reblade all LP machine rotors.

The 11.2 MWe IP machines, which were late substitutes for the planned heavy water distillation plant, have been very prone to blade failures, due primarily to the high steam bending stresses in the blades being well above that applicable to contemporary machines. Higher strength blades manufactured from FV 520, a 14 percent chromium, 5 percent nickel material, are currently being tried out on these machines.

As mentioned previously, the HP machines at Wairakei are all operating at very much reduced load due to the fall-off in steamfield pressure, and consideration is being given to re-siting two of these machines at the planned Ohaki Geothermal Power Station so that more efficient use can be made of the HP steam which will be initially available at that site.

Examination of the machines has shown no major repairs necessary with the exception of perhaps the complete replacement of the exhaust casings.

In the early years of operation a case of "standby corrosion" was experienced with one turbine when, owing to imperfect isolation, steam seeped into the casing of the idle machine from the exhaust end. The presence of air and condensation proved a particularly noxious and corrosive mixture and the rotor and diaphragms suffered attack. Improved methods of isolation assisted by hot air ventilation for drying out turbines after shutdown has prevented a recurrence of this trouble.

Jet Condensers The jet condenser shells on the Wairakei machines are made from mild steel with the wetted surfaces epoxy coated (Calvinac). This coating has stood up remarkable well considering the presence of warmth, moisture, oxygen and hydrogen sulphide, and still exists over some 80 to 90 percent of the total internal surface area. Site application of the original epoxy coating has proved very difficult and station staff have had to use a different epoxy coating for repair work. This substitute material, however, only has a service life of between four to five years.

A significant problem with the condenser bodies is that corrosion, once it commences, proceeds rapidly to excavate very deep pinhole cavities which have on occasions penetrated the shell. Repairs to corrosion pits are made by welding, but if the welds are not ground smooth and epoxy coated, corrosion proceeds extremely rapidly at the weld fusion zones. Photograph 7 shows condition of epoxy coating within jet condensers. The impact forces of the cooling water on the condenser floor plates have resulted in these plates frequently becoming detached. However, by strengthening the mounting framework and making the floor plate attachments more resilient by introducing rubber washers at each joint interface and by the use of stainless Belleville washers, the station staff have had some success in containing this problem.

Gas Extraction System Initially, high speed centrifugal gas exhausters were installed on the LP machines, but these proved very unreliable mechanically and were replaced with steam driven ejectors. These have proved to be very reliable, but inefficient in the use of steam.

The ejector condensers are subject to heavy sulphur encrustation, and corrosion in this area is fairly severe. In general, ejector condenser bodies with epoxy linings last approximately six years, although one of the original ejector condensers coated with Calvinac epoxy is still in service.

In 1971 the gas extraction and water discharge pipework from the ejectors was replaced with polyester asbestos and this has given exceptional service and is expected to last indefinitely on this duty.

Electrical Equipment The only satisfactory material found for electrical contacts at Wairakei has been platinum; silver and even gold contaminates rapidly in the hydrogen sulphide polluted atmosphere.

Copper must be tinned to avoid corrosion, and wires must be stripped using thermal strippers, otherwise the "nicks" in the tinning caused by blade strippers allow corrosion to commence, resulting in the tails falling off the wires.

The brush gear has been a continuing source of trouble and requires constant routine maintenance.

Cooling Water Discharge Culverts Due to the use of jet condensers at Wairakei, hydrogen sulphide gas gets carried over into the cooling water culverts where it collects in pockets located above the water level. The design of the culverts at Wairakei is such that during normal operation the culverts do not run full and there exists a 200 mm (8 in) gas space above the water level. The hydrogen sulphide which collects in this space oxidises to sulphuric acid which attacks the exposed wet concrete causing the surface to crumble and break away. Those areas of culvert that are below the operating water level exhibit little or no sign of deterioration.

Concrete loss on the roof areas of the culverts has been extensive. (See Photograph 8.) On large areas the first layer of reinforced steel has been exposed, and in places the steel has been completely corroded through. The integrity of the culvert structure is still adequate, but a solution to the problem is urgently required.

Since 1974 a test programme has been implemented to evaluate possible repair and cure methods for the culvert roof corrosion problem and to test concrete protective coatings for new geothermal installations. To date, the most promising results have been achieved by spraying the roof with a urethane expansion foam to a depth of 37 to 50 mm (1½ to 2 in). Care is taken to make this surface reasonably smooth as an elastometric polyurethane sealing coating (Irathane 141) is applied to it to provide resistance against chemical attack. Photograph 9 shows a section of roof being foam covered and the Irathane primer coating being applied. Photograph 10 shows the same roof area after three years operation.

Epoxy coated concrete block samples have been positioned in the culvert corrosion zone for evaluation purposes. No results are as yet available on this work.

Future Management Strategies It is New Zealand Electricity management's intention that Wairakei be maintained at its present level of production provided economic means are available to sustain this production. To this end active steps are being taken to investigate the feasibility of reinjecting the waste hot water from the field as a means of alleviating and correcting the decline in field pressure. Management of the reservoir is the primary object of this reinjection. Secondary effects are the possible curtailment of ground subsidence and lessening of environmental problems created by surface discharge of geothermal waste fluids to the Waikato River.

Currently, tests are in hand to evaluate the most promising reinjection sites at Wairakei, and a trial reinjection of approximately 700 tonnes/hour is to be undertaken on a well sited near the western field margin. The well selected for this test has always followed field pressures changes closely and rapidly and can be considered to be at the same pressure as the main production area. The water temperature at which reinjection can be accomplished satisfactorily is of vital importance to the economic viability of the scheme because of the low waste water temperature existing from the LP flash facilities (125°C).

Existing wells which, up to now, had not been considered economic for connection to the steam transmission system due to their remoteness, are now being reappraised. A potential of approximately 20 MWe exists from one group of wells and Ministry of Works and Development are currently drawing up engineering cost estimates to link these wells into the steam transmission system.

Partial replacement of the steam activated gas ejection on the condensing turbo-generators, with liquid ring compression is identified as an area where the economy of operation of the plant can be improved.

Conclusion It is acknowledged by New Zealand Electricity that the initial operating pressure of the 'A' station plant was too high and the overall installed capacity of the project too large for the geothermal resource to sustain. The need to assess more accurately the reaction of a field to exploitation will be a very important consideration in any future geothermal electrical power development in New Zealand.

The cancellation of the heavy water distillation plant, and its replacement by additional turbo-generators, has resulted in a complex of small machines on the 'A' station which is costly to maintain, in comparison to 'B' station.

The general condition of plant on both 'A' and 'B' stations is such that a further fifteen to twenty years operation is expected from the equipment before maintenance costs become excesive. It will still be necessary, however, to maintain the same high degree of vigilance, which in the past has achieved an enviable record of plant availability.

The use of unsophisticated materials was an important design decision which in the main has been substantiated. The inclusion of a corrosion allowance has, however, saved the "station end" half of the large HP steam mains from early replacement due to condensate corrosion.

The use of mild steel protected with epoxy coatings has stood up well in the harsh condenser environment at Wairakei.

The level of future output from the station is open to question. Present trends indicate that the rate of power output drop is declining. The performance of the field during the forthcoming winter generation period will be watched closely to see if this trend continues. In the long term it is the aim of New Zealand Electricity to maintain a geothermal energy resource at Wairakei which, with the possible assistance of reinjection, will produce power at near the present level for a very long time. Wairakei, it is hoped, will be like your grandfather's axe, four new shafts, two new heads, but still the same axe.

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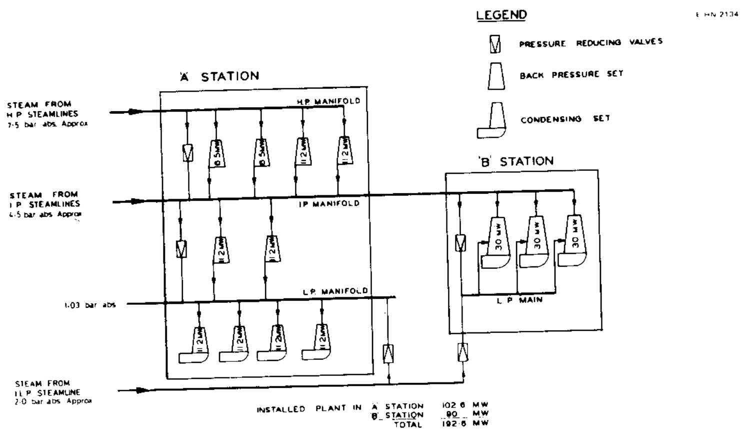


Figure No. 1a Flow diagram showing machine arrangement at Wairakei A and B stations.

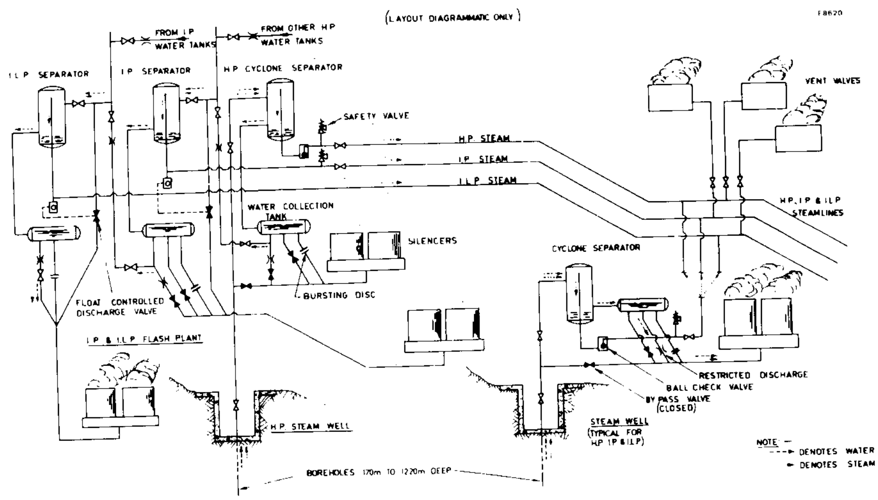


Figure No. 1b Diagrammatic arrangement of steamfield plant at Wairakei.

Figure No. 1

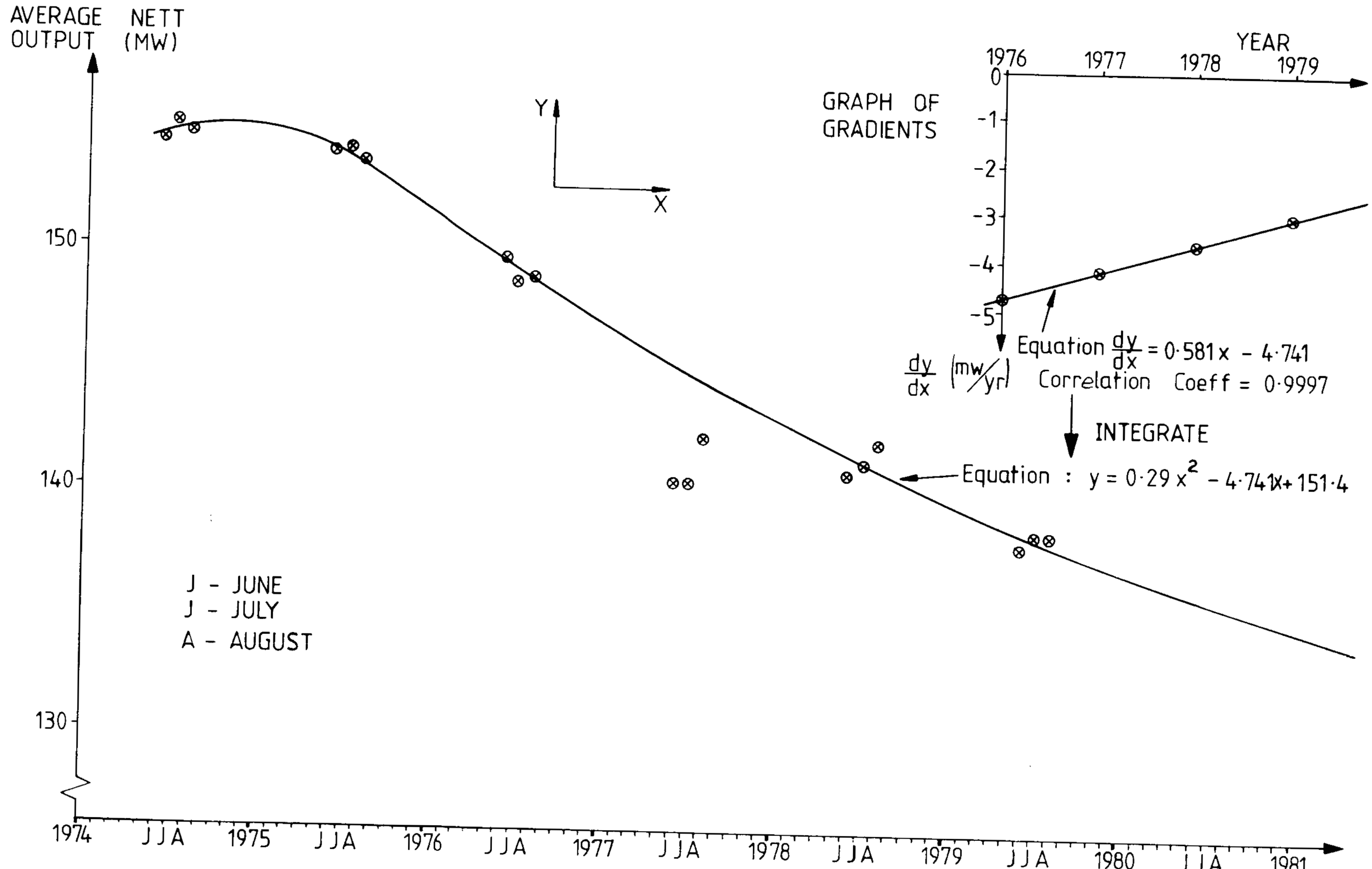


FIG 2 . GRAPH SHOWING DECLINE IN AVERAGE NETT WINTER POWER GENERATION AT WAIRAKEI

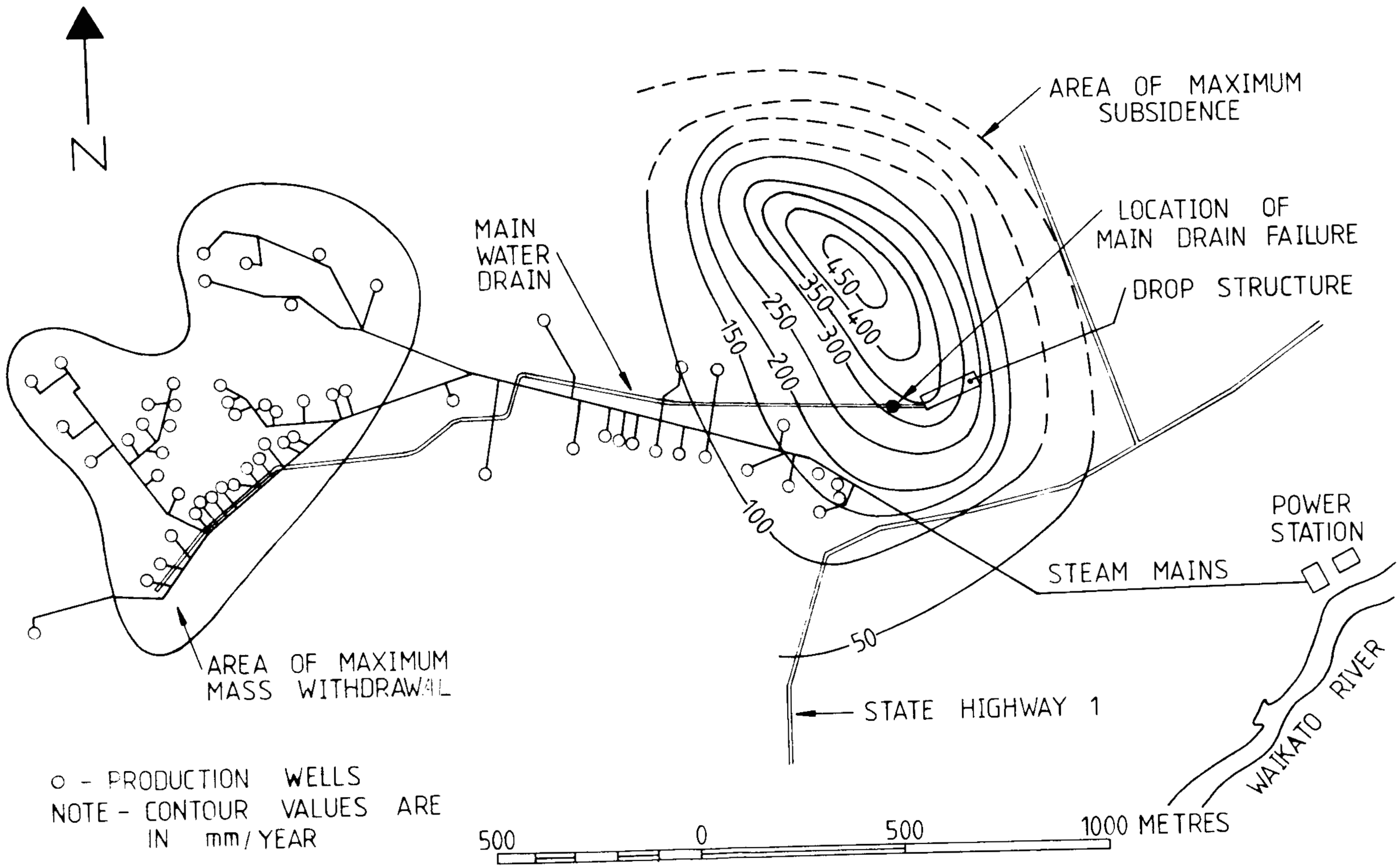


FIG 3. TYPICAL SUBSIDENCE RATE IN WAIRAKEI PRODUCTION FIELD 1964 - 1974 [AFTER STILWELL, ET AL., 1975].

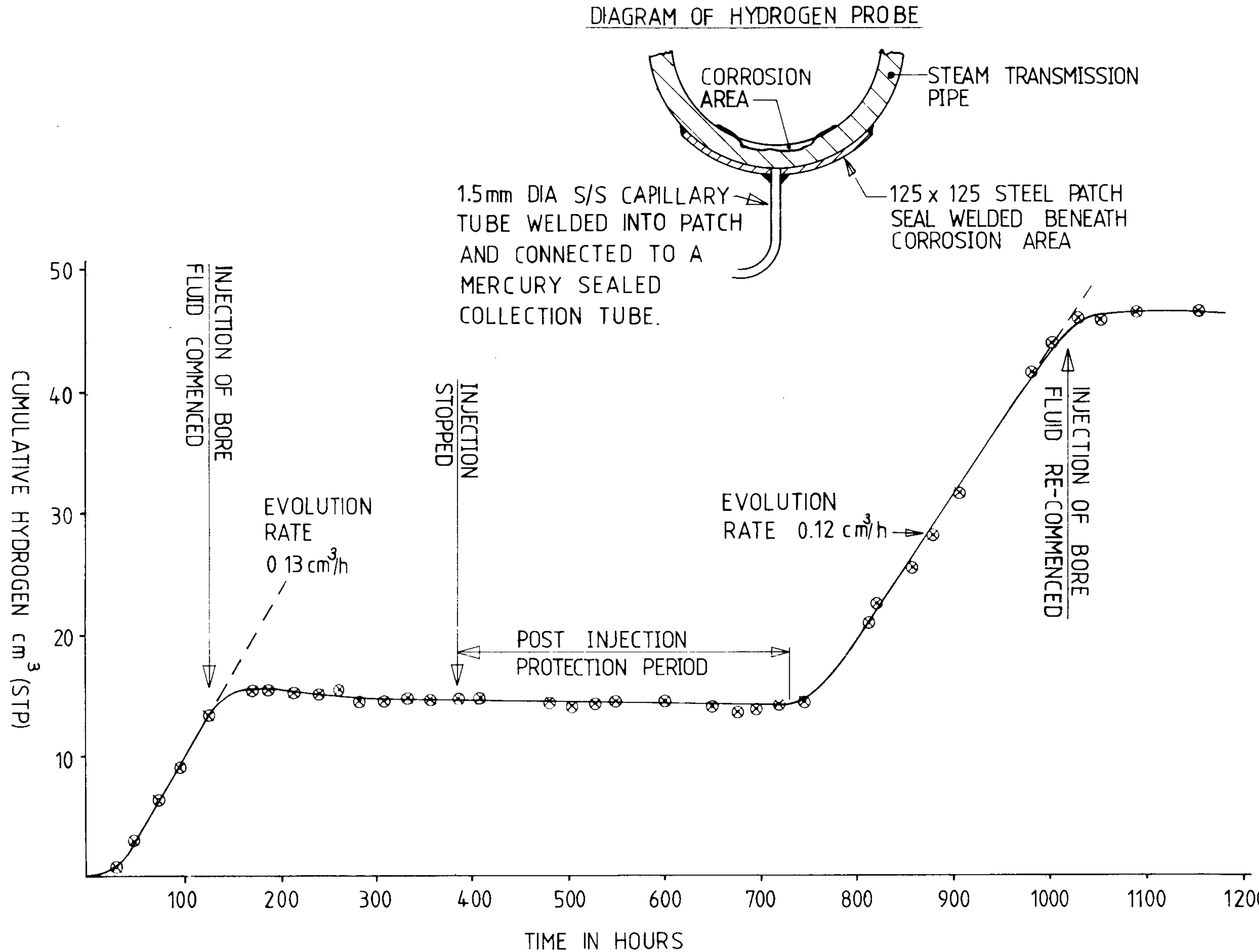
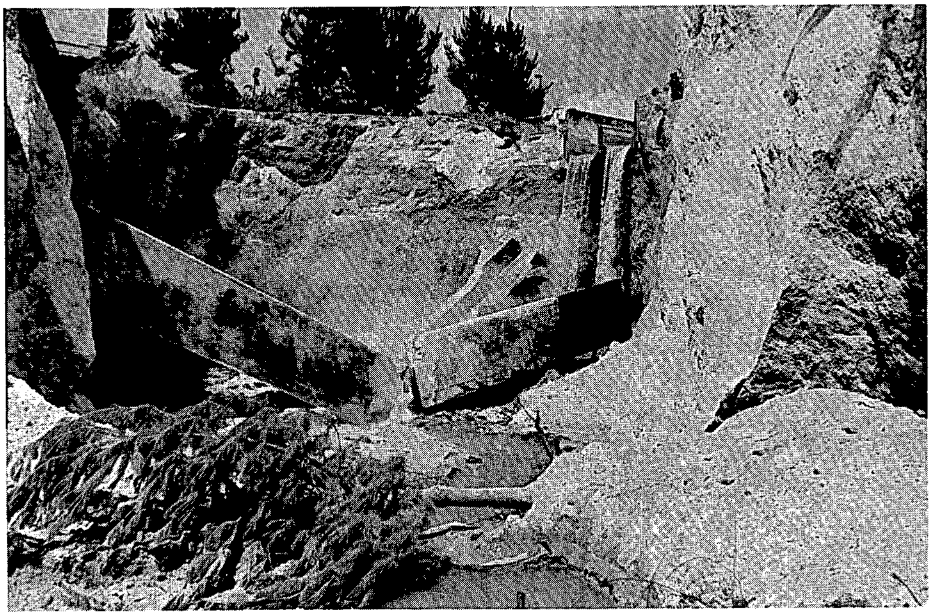
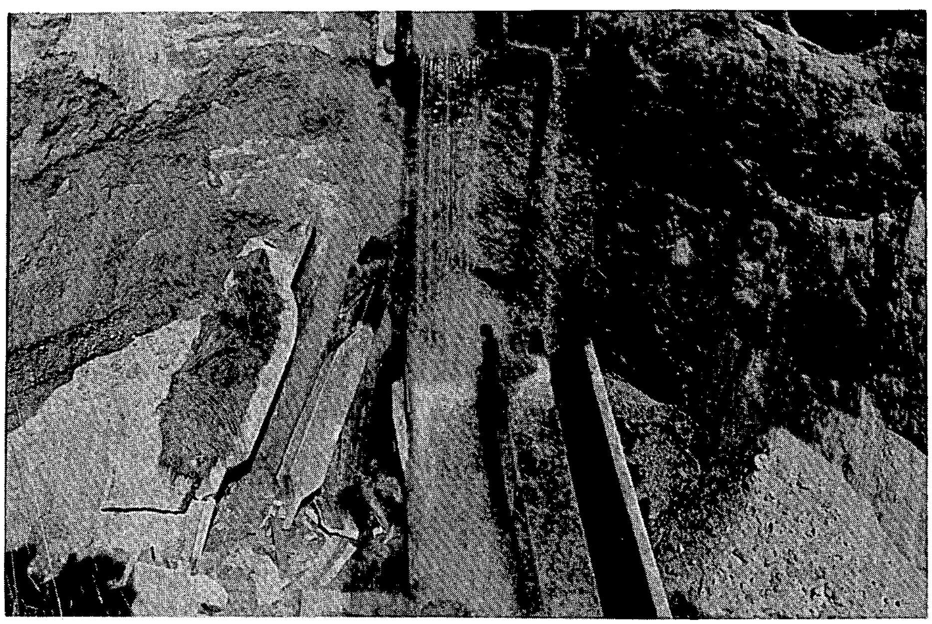


FIG. 4 WAIRAKEI HP STREAM TRANSMISSION PIPELINE WELL FLUID CORROSION INHIBITING TEST-HYDROGEN PROBE RESULTS FOR PERIOD 1ST APRIL TO 18TH MAY 1980.



Photograph 1 View showing failure of main drain which necessitated the only major unscheduled steamfield shutdown in the last 10 years.

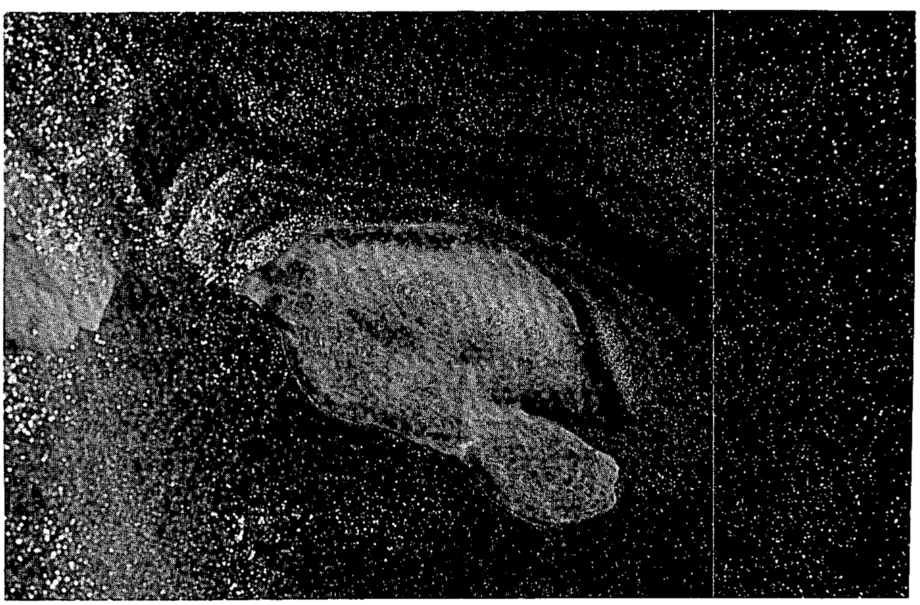


Photograph 2 Another view of damaged drain.
Note: The thickness of silica build-up on the right hand drain channel.

Photographs 1 and 2

Direction of
Steam flow

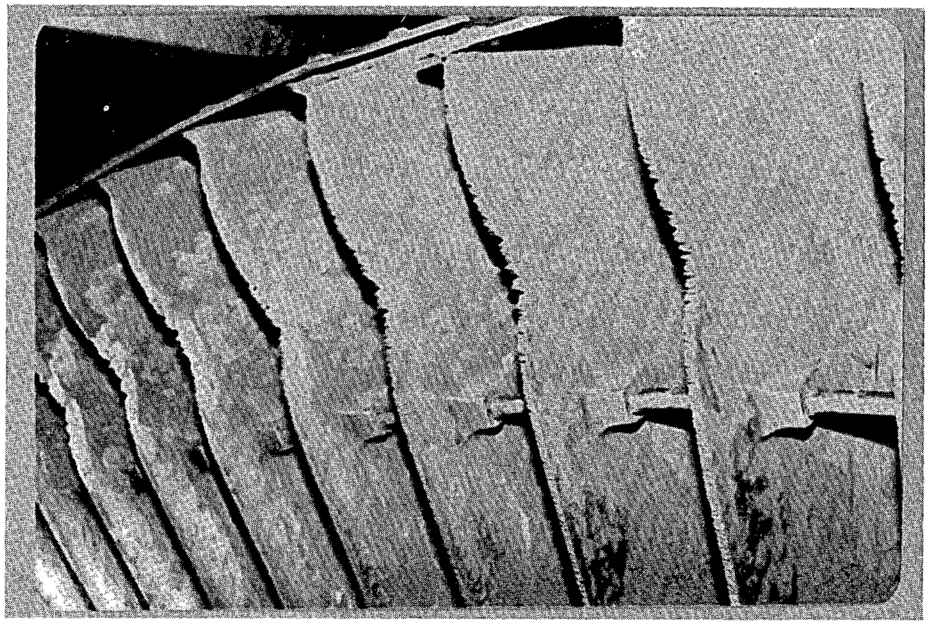
Photograph 3: Typical H.P. Pipeline corrosion cell.



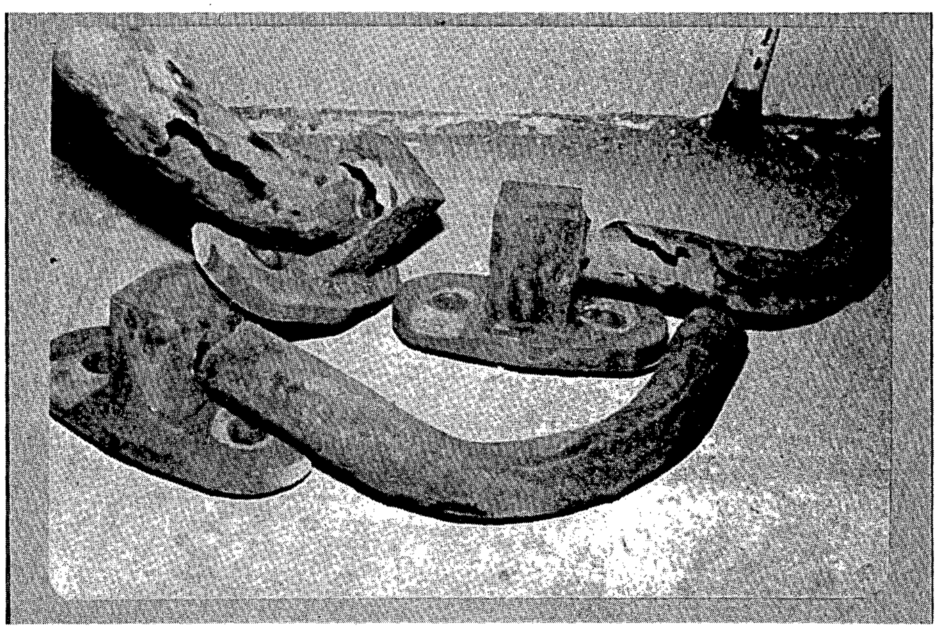
Direction of
Steam flow

Photograph 4: H.P. Pipeline corrosion cell.
Note: Magnetite redepositing along
downstream edge

Photographs 3 and 4

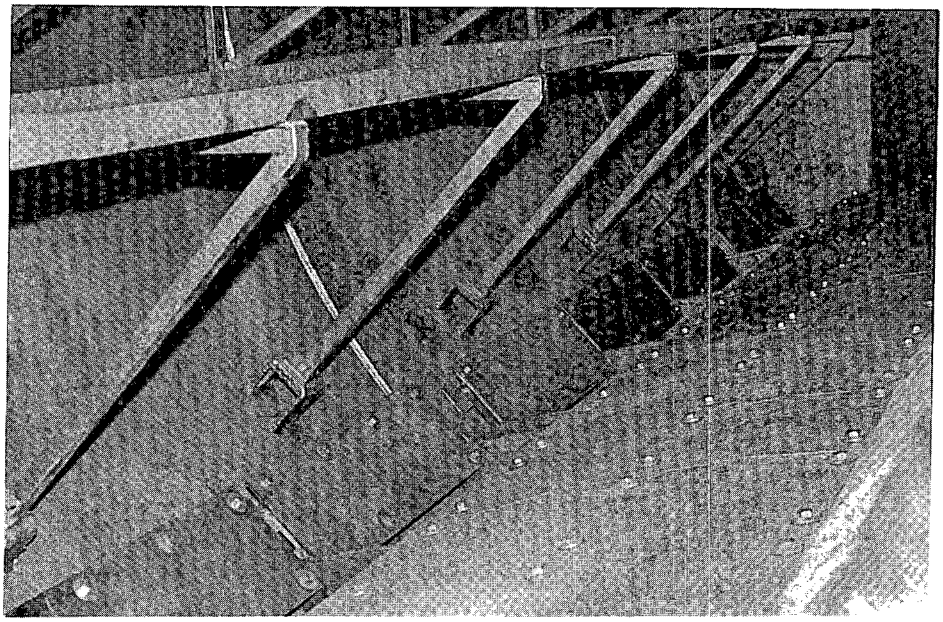


Photograph 5: Erosion damage to mixed pressure M/C exhaust end blades after 135,000 hours operation.

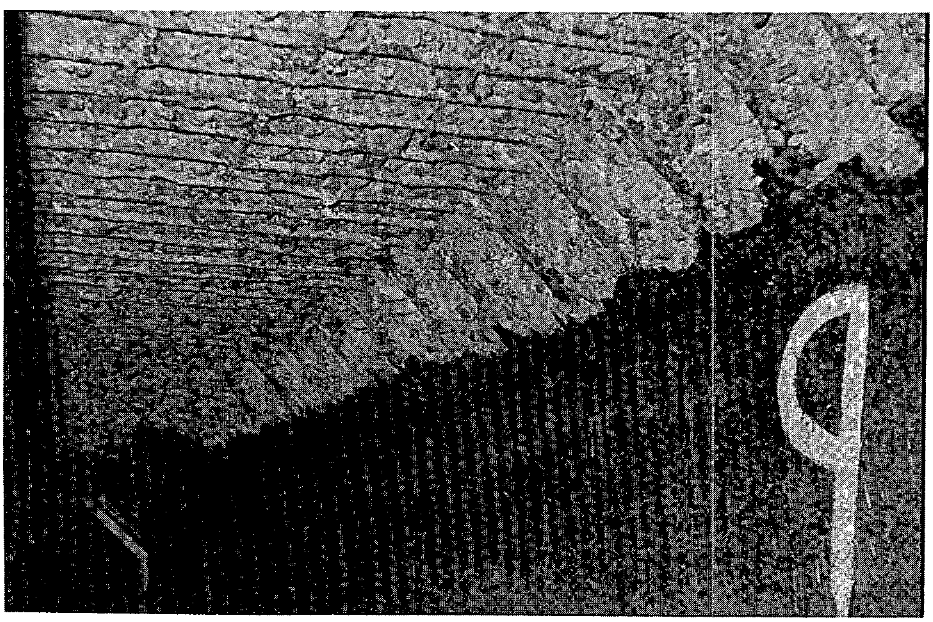


Photograph 6: Intermediate pressure M/C casing drain corrosion damage.

Photographs 5 and 6

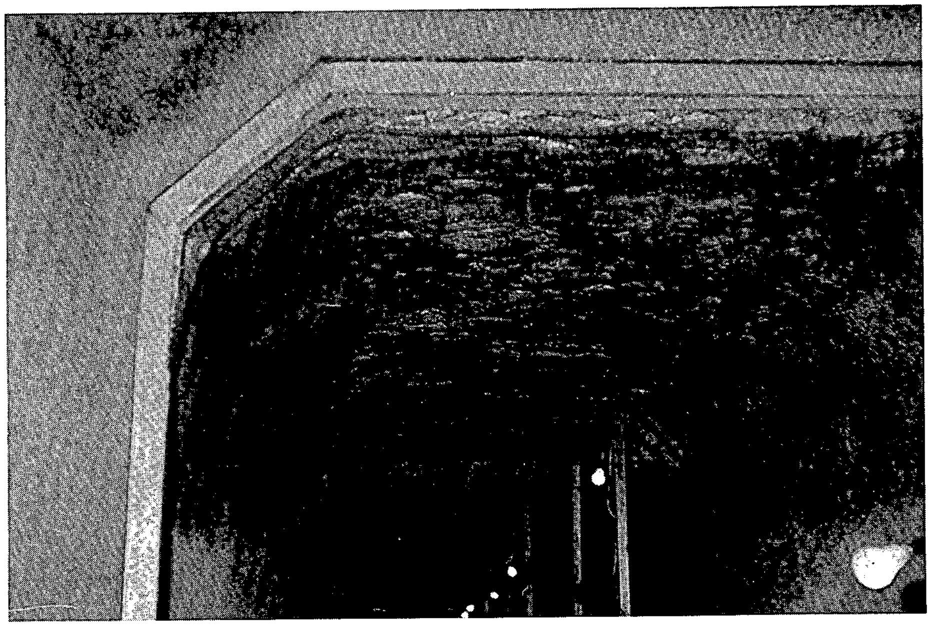


Photograph 7: View of jet condenser floor plate and side wall areas. Note the good condition of epoxy coating on wall.



Photograph 8: View of cooling water outlet culvert showing hydrogen sulphide induced attack on culvert roof.

Photographs 7 and 8



Photograph 9 Showing part of C.W. outlet culvert roof coated with urethane foam and sealing coat of elastometric polyurethane applied.

Photograph 10 Showing the same culvert roof after three years exposure to sulphuric acid attack.

Photographs 9 and 10

PROJECTED GEOTHERMAL ENERGY DEVELOPMENT IN CANADA

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Introduction A systematic evaluation of geothermal energy resources in Canada was begun in 1973 with the compilation of an inventory of thermal springs and young igneous centres (11) and a study of the thermal regime of the Central Canada Plains (15). The status of this work is still very preliminary. The nature, distribution and grade of the geothermal resource-base can be estimated within reasonable limits but the impact of future economic and political constraints, and the rate of development of new conversion technologies are more difficult to forecast. Thus, projections of geothermal energy development in Canada are necessarily less precise than estimate of the resource-base.

Resource-base Recoverable geothermal heat is present in three geologically and geographically distinct regions of Canada: 1. The Central Canada Sedimentary Basin, 2. a region of south-central British Columbia characterized by high heat flow and Basin and Range style structures and, 3. thermal anomalies associated with Quaternary volcanic belts in western British Columbia. In each of these regions reconnaissance surveys, designed to identify potential targets, are in progress and, in addition, site-specific work presently underway in the sedimentary basin and in the western volcanic belts is scheduled to bring full-scale pilot plants on stream within the next decade.

Central Canada Sedimentary Basin Relatively high thermal gradients in the Central Canada Sedimentary Basin are caused by the insulating effect of a thick cover of flat-lying sedimentaryrocks on the crystalline basement. The sediments, which range in age from Cambrian to Tertiary, are thickest in the west and include numerous regional aquifers containing enormous volumes of hot water and brine. Using existing oil well data Sproule (15) has identified those parts of the basin where bottom-hole temperature exceed 80°C (Fig. 1). The hottest, up to 175°C, are recorded in a remote region of northwestern British Columbia and Northwest Territories, but temperatures above 100°C are present at moderate depths over most of the settled region of southwestern Alberta and part of Saskatchewan. Fifty percent of the recorded temperatures lie along gradients

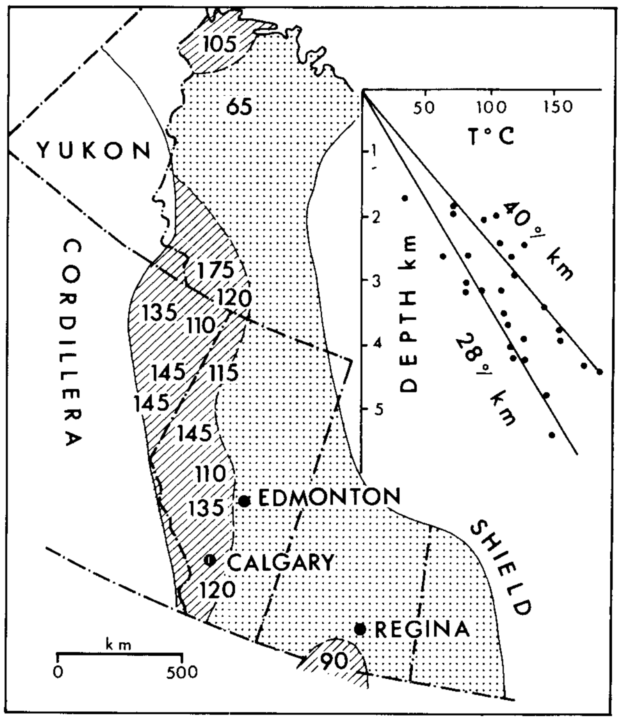

Figure 1 Maximum bottom-hole temperatures in the Central Canada Sedimentary Basin. The dashed line separates regions in which temperatures are above and below 80°C. Graph shows gradients in the hotter regions. (after Sproule 1977)

between 28°C/km and 40°C/km and the average for the high temperature portion of the basin is 33.3°C/km.

The total heat stored in the Western Canada Sedimentary Basin is enormous. Jessop (4) has calculated that the total heat in pore fluid above 0°C is 4.6 x 10^{19} BTU. Such figures have no real significance when one considers that they apply to an area of some 800,000 square miles with only 3 cities of more than 100,000 people. Unlike oil and gas, which are still being produced from this same basin, low-grade geothermal heat cannot be transported. A more realistic estimate of usable reserves can be achieved by considering the number of population centres that lie in those parts of the basin where bottom-hole temperatures are near 80^{o}C. Using Gorrell's (3) figures (Table 1) for a theoretical "average well" drawing from an "average reservoir" of 3 Km^2 and assuming complete recovery from an area proportional to the population of each individual city, a rough estimate of available heat can be calculated. The figures in table 2 are based on reservoirs of 100 Km^2 per 10,000 population. The extent to which this is actually developed will depend on the economic as well as the technical success of an experiment being conducted in Regina (17) where a demonstration facility designed to utilize hot NaCl geothermal brine for space heating is under construction at the University of Saskatchewan. A 7000 foot production well has been drilled and is presently being tested. If sufficiently high temperatures and flow rates are achieved a second, injection hole will be drilled nearby and brine, circulated from one hole to the other, will be used to pre-heat air entering a complex of new university buildings.

South-Central British Columbia A north-south trending corridor of highly conductive rock beneath south-central British Columbia was identified by geoelectrical surveys more than ten years ago (1). It is interpreted to be a linear zone of abnormally high upper mantle and lower crustal temperatures in which horizons of partial melt have formed. The surface structure is characterized by Tertiary, normal faulting, subsidence structures, thick deposits of potash-rich, siliceous volcanic rocks and associated high-level plutons of syenite. Regional heat flow values of 1.86 HFU are reported by Jessop (5) and the gradients of two test holes drilled in 1978 are in the order of 54^{o}C/km (7).

On-going research in this region includes drilling additional heat-flow holes, surface mapping and a study of the distribution and thermal effects of radioactive, heat-producing elements in the syenitic rocks (6). The objective is to locate a suitable target for a future hot-dry-rock experiment. From the little data available it is not possible to make a quantitative estimate of H.D.R. reserves in Canada. However, the resource-base, within reach of drilling, is assumed to be very large.

Well Depth	3Km
Reservoir Temperature	100^{o}C
Area of Drainage	3Km^3
Thickness of Reservoir	100m
Average porosity	10%
Volume of Water	30 x 10^{6}m^3
Production Rate	100m^3/hr
Heat Drop	70^{o}C
Available Heat	70 x 10^{3}kcal/m^3
Oil Equivalent	115 Bbls/day

Table 1 Estimated production from an average, hypothetical geothermal well. (from Gorrell 1978)

Volcanic Belts Quaternary volcanoes lie along three distinct belts in western and central British Columbia (Fig. 2). The Garibaldi belt of southwestern British Columbia is a northern extension of the high Cascades of western United States. It includes at least 32 eruptive centres that run north from Mt. Garibaldi, near Vancouver, some 200 km to Meager Mountain near the town of Pemberton. The Anahim Volcanic Belt comprises a fairly narrow east-west belt of some 37 centres that extend approximately along latitude 52^{o}N from the Coast, inland for 600 km. Still farther north, the broad Stikine Volcanic Belt includes over 50 centres of which several are only a few hundred years old. Individual volcanoes within each belt have erupted lava ranging in composition from basalt to rhyolite. Those that have produced a significant volume of acid lava and are also associated with active hot springs are considered to have the greatest geothermal potential and have been selected for more detailed exploration (Fig. 2). Because these targets theoretically have the potential to produce a high temperature resource capable of power generation, they have been the main focus of current exploration and development. Also, because there are no natural, surface manifestations of high temperature (>65^{o}C) associated with any of these centres their potential cannot be assumed without extensive subsurface work. Meager Mountain, at the north end of the Garibaldi Volcanic Belt is the first, and so far the only, volcanic centre in Canada where sufficient geophysical work and drilling have been done to prove the presence of a high temperature reservoir. However, the results

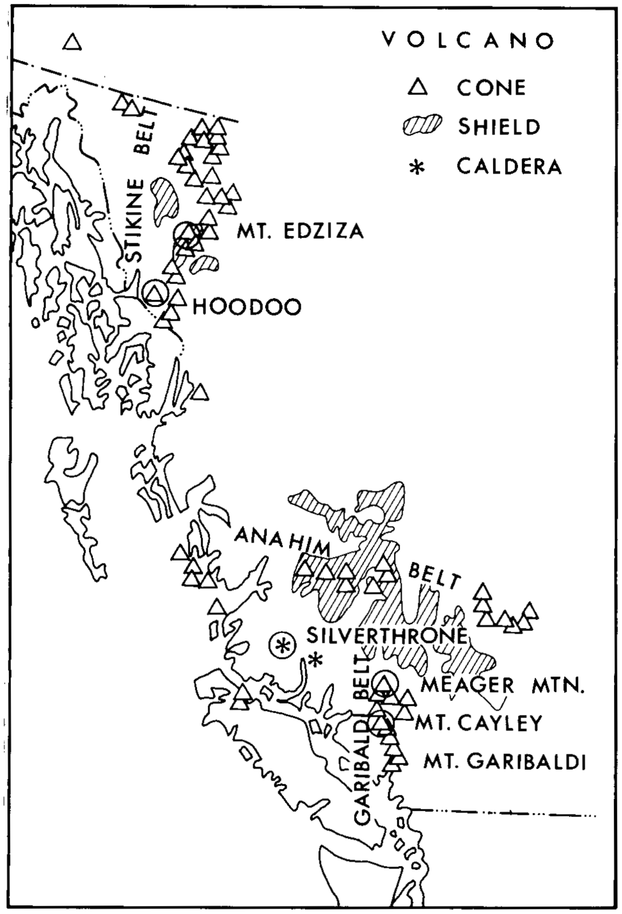

Figure 2 Distribution of Quaternary volcanic belts in western Canada. Circled areas are those considered to have geothermal potential.

of that work provide a rational basis for extrapolation to other centres of similar age, composition and structure.

Meager Mountain Meager Mountain is an andesite, dacite, rhyodacite composite dome at the north end of the Garibaldi Volcanic Belt (9). It rests on a crystalline basement comprising granitic and metamorphic rocks of the Mesozoic, Coast Plutonic Complex (10). Local porosity and permeability in the underlying basement are believed to have been considerably enhanced by fracturing during the initial explosive eruption of Meager Mtn. about two million years ago (8). Subsequent activity produced a series of overlapping domes and pyroclastic wedges that become younger toward the north and culminate in the Bridge River pumice flows which were erupted from the north side of the mountain about 2400 C^{14} years ago. Thermal springs, producing moderate flows of $\pm$ 60°C water, on the north and south sides of the mountain are the only natural manifestations of high subsurface temperature.

Resistivity surveys have defined large bodies of highly conductive basement rock adjacent to the north and south slopes of Meager Mountain and exploratory diamond drilling has confirmed that these anomalies are in fact due to high temperature reservoirs (2). A single hole in the north reservoir encountered temperatures above 100°C at a depth of 570 m and the hottest of 10 holes in the south reservoir recorded temperatures above 200°C at 367 m. Additional drilling and resistivity work are in progress to define the extent of the reservoirs and determine the flow characteristics of hot wells. A projection by Stauder, based on present estimates of reservoir size and temperature, puts the ultimate, combined capacity of the two Meager Creek reservoirs at 1000 Mw_e.

Other Volcanic Centres On the basis of their similarity to Meager Mountain at least 4 additional volcanic centres in British Columbia are considered to have commerical geothermal potential. Each of them is estimated to have erupted more than 5 km^3 of acid magma within the last one million years and each is associated with nearby thermal springs. Mt. Cayley (13), which lies in the Central Garibaldi Belt south of Meager Mountain, is close to existing transmission lines. Preliminary surface mapping has been completed and contracts have been let for a limited program of resistivity surveys and drilling during the summer of 1980. Mt. Silverthrone (12), because of its remote location in the central Coast Mountains, has not been studied in detail. However, reconnaisance mapping has shown it to be one of the largest centres of Quaternary, acid volcanism in British Columbia. It has been active within the last 25,000 years and it is associated with several thermal springs. Detailed mapping is scheduled to begin in 1980. Mt. Edziza (14), which has already been mapped in great detail, and Hoodoo Mountain, which is scheduled for detailed study in 1981, are likely geothermal targets but both are too far from existing markets and transmission lines to warrant subsurface exploration at this time.

In the absence of detailed subsurface data estimates of capacity for volcanic targets (other than Meager Mountain) are necessarily vague. However, it is reasonable to assume that some relationship exists between the volume of acid ejects (less than 1 my old) in the volcanic edifice and the size of the associated thermal reservoir. Mt. Cayley and Hoodoo Mountain each has a volume about one-third that of Meager Mountain, whereas Mt. Silverthrone and Mt. Edziza are each at least double the volume of Meager Mountain. Thus, using the above assumption the possible capacities for the five known volcanic targets in British Columbia are: Meager 1000MW, Cayley 300MW, Hoodoo 300MW, Silverthrone 2000MW, Edziza 2000MW, for a total resource base of 5600MW.

Projected Geothermal Development The vast amount of low grade heat stored within the Central Canada Sedimentary basin cannot, at present, be economically extracted for power generation. However, several direct use applications, such as that under development at Regina, are being planned and an increasing number are expected to be brought on line within the next decade. The projections shown in Fig. 3 are based on a unit capacity of 5MW and a doubling time of 4 years.

Two factors, the escalating cost of oil and gas, and improved efficiency of low temperature conversion systems, will eventually make the low grade heat of the sedimentary basins competitive with other sources of electrical energy. Because electricity, unlike fluid for direct use, can be transmitted great distances from source to market it will be possible to exploit the more remote, higher temperature parts of the basin. The feasibility of using brine in the 150°C to 200°C range for power generation in the remote northeastern part of British Columbia and adjacent Northwest Territories is presently under study. Commerical developments in this region, particularly mining operations, are faced with fuel costs at least double that in other parts of the country. Thus the installation of a binary-cycle geothermal generating plant for specific commerical operations will probably be feasible within this decade. Projections in Fig. 3 are based on a unit capacity of $30MW_t$ and a doubling time of five years.

The exploitation of a hot-dry-rock resource for power generation in Canada is solely dependent on the development of an effective technology in the United States. By 1985 a suitable target is expected to have been identified in south-central British Columbia but is is unlikely that any attempt to develop it will be made until a fully operational test facility is in operation elsewhere. H.D.R. power generation in Canada is unlikely before the year 2000.

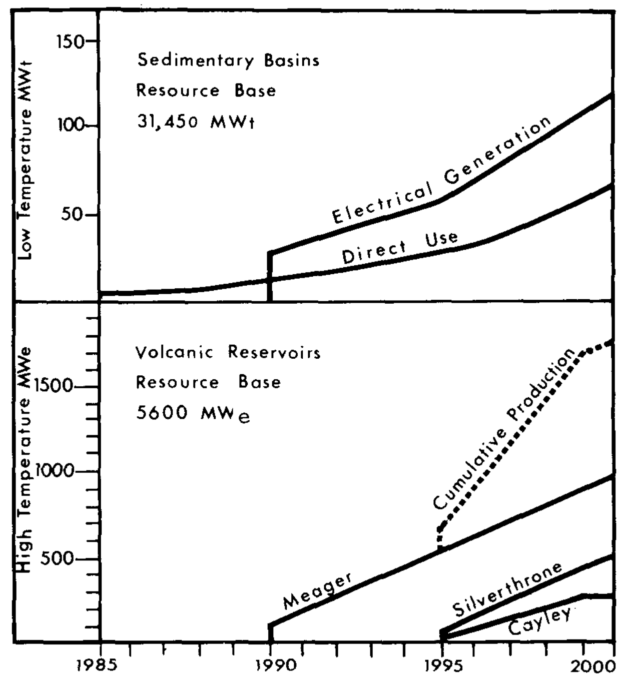

Figure 3 Projected geothermal energy development in Canada to the year 2000.

Power generation from the high temperature, volcanic reservoirs is feasible with existing technology; thus the only constraints are economic. With adequate funding a $100MW_e$ plant drawing on 20 wells could be in production at Meager Creek by 1990 and the total capacity of $1000MW_e$ could be on line by the year 2000.

Because of its proximity to Meager Mountain, and to existing transmission lines, the development of Mt. Cayley is expected to parallel that of Meager Mountain within no more than five years.

Mt. Silverthrone is about 150 km of mountains terrane from the nearest transmission line, but it is relatively close to good harbours on the coast. If it is developed within this decade the power will probably be used to support a local, coastal industry rather than added to the provincial grid.

Mt. Edziza and Hoodoo Mountain are too remote from markets and transmission lined to justify development for at least ten years. However, major hydroelectric development being planned for the Stikine and Iskut Rivers will eventually bring transmission lines to within a few km of both these volcanoes. When these are in place, sometime after 1990, it seems likely that an attempt will be made to tap the geothermal resources of the region.

Summary The estimates of geothermal energy production given in Fig. 3 are based on very incomplete data and are thus subject to continuous revision. In one sense they are optomistic, in that each of the five volcanic targets described here is assumed to be associated with a thermal reservoir. However, no provision has been made for the discovery of new target areas, nor has any attempt been made to estimate the impact of substantial breakthroughs in low temperature conversion technology or H.D.R. utilization. Both of these will certainly occur within the next decade. Thus even if the specific targets identified in this report do not come up to our present expectations it is reasonable to expect an upward revision in the estimate of total geothermal energy production beyond 1990.

City	Population (thousands)	Reservoir Area Km	Potential MW_t
Alberta			
Edmonton	442	4400	11,800
Calgary	433	4300	11,500
Lethbridge	44	440	1,000
Red Deer	28	280	750
Medicine Hat	27	270	
St. Albert	18	180	500
Grande Prairie	15	150	400
British Columbia			
Dawson Creek	12	120	300
Saskatchewan			
Regina	147	1470	4,000
Moose Jaw	32	320	800
Swift Current	16	160	400
		TOTAL	31,450

Table 2 Geothermal resource base for the Central Canada Sedimentary Basin adjusted to population centres.

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TREND OF GEOTHERMAL DEVELOPMENT AND UTILIZATION

FOR THE YEAR OF 1979

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Present Situation in Japan In 1979, all geothermal power plants were in successful operation with the performance records as shown in Table 1. Among these plants, Hatchobaru Geothermal Power Plant (No. 172 in Figure 1) had an insufficient steam output at the commencement of operation, thus allowing a licensed capacity of less than 50 MW for the facilities, but new wells were dug successively and licensed capacity was raised to 48 MW in the latter half of 1979. Thereafter it reached 50 MW in March and then 52 MW in April of 1980 as steam production wells became complete.

Operation factor exceeded 90 percent for each plant, going in the neighborhood of 100 percent. Load factor was also more than 80 percent for every plant except Otake Geothermal Power Plant (No. 172 in the figure) which had a decrease in load factor due to periodic repairs, thus recording far higher factors than those of other conventional thermal or nuclear power plants.

At present, Mori Geothermal Power Plant (tentative name, No. 110 in the figure) located in the southern part of Hokkaido where several steam production wells have been completed, is under construction with an aim of starting operation in 1981. Japan Metals and Chemicals Co.,Ltd, is constructing the steam generating facilities and Hokkaido Electric Power Co., Inc. is building the power plant. The installed capacity is estimated at 50 MW. To this end, 14 production wells and 7 injection wells are to be dug.

Contribution of Japanese Industries Abroad
Table 2 shows foreign geothermal power plants being planned or in construction which will utilize Japanese equipment.

Geothermal Resources Survey in Japan The Agency of Natural Resources and Energy, Ministry of International Trade and Industry, annually conducts a survey for development of geothermal resources which includes a basic survey and an environmental survey.

The basic survey is intended for the development of geothermal resources in undeveloped areas by conducting a survey on the earth's surface in the first year and a boring survey (one boring of about 500 to 800 m in every area) in the subject areas. The environmental survey is intended for investigating in advance the effect of development on the environment in the subject areas designated by enterprises planning power generation. This survey includes two borings of 1,000 m order in every area, a meteorological survey, a plant ecological survey, a survey of natural steam vents, river water, etc., a survey on the effect of ejection and/or injection from geothermal wells on the atmosphere, river water, etc., a seismic survey, etc.

The basic survey conducted in 1979 covered the following five areas: Atosanupuri in Kussharo (No. 102 in the figure); Iwakisan in Ikarigaseki (No. 116); Yuda in Tsuchihata (No. 122); Akakura in Kurikoma (No. 123); and Yunohira in Beppu-Kuju (No. 172); in each of which a gravimetric survey, an electrical, a survey on seismic activity, a survey on hydrothermally altered zone, and a geochemical survey were conducted.

Four areas were selected for the environmental survey in 1979. They were Komonomori in Hachimantai (No. 119); Asahidai in Hijiori (No. 124); Obeno in Kirisima (No. 179); and Oogiri in Kirishima (No. 179).

In addition to the above, the Agency of Natural Resources and Energy decided to conduct a survey for promoting development on subject areas that have been already developed to some extent, and in 1979, Onikobe located in the northeast of Honshu was selected and a geochemical survey was performed on the area.

The above-mentioned is the governmental surveying activities, and it should be added that private enterprises' surveying activities have been getting more active year by year.

Research Activities on Geothermal Energy
Research work on technology for development of geothermal energy resources is taken up as one of the most important subjects of Agency of Industrial Technology, Ministry of International Trade and Industry. The subjects of study taken up in 1979 are listed as follows:

1. For Government research institutes
   a. Research on Hydrothermal Systems in Geothermal Areas
   b. Research on Exploration Methods for Wide Area Deep Geothermal Resources
   c. Studies on the Drilling and Fracturing Techniques for Hot Dry Rock
   d. The Material Development Study for Geothermal Power Generation

2. For non-Government research institutes under an entrusted contract with the Government
   a. Studies of the Methods for the Survey of Wide Area Geothermal Structure
   b. Development of the Drilling Mud Available under a Geothermal Environment
   c. Development of the Cement Available under a Geothermal Environment
   d. Development of the Drilling Techniques for High Temperature Formations
   e. Studies on Logging Technology in Geothermal Wells
   f. Study on Underground Reinjection Mechanism of Disposal of Hot Water
   g. Development of Power Generating Plant Utilizing Geothermal Hot Water
   h. Feasibility Study on Electric Generation Systems Utilizing Hot Dry Rock
   i. Research and Development of Technology for Preventing Adhesion of Scale from Geothermal Hot Water
   j. Research and Development of Technology for Removing Hydrogen Sulfide from Geothermal Hot Water

In addition to the foregoing, the Demonstration Program for Environmental Protection on Development of Large Scale Power Plants using Deep Geothermal Resources that had been started as a 5-year schedule in 1978 by the Agency of Natural Resources and Energy and the Agency of Industrial Technology has entered upon the second year. This program covers Hohi District in the central part of Kyushu and has been conducted by Japan Electric Power Development Co., Inc. on a consignment basis.

Training of Engineers from Developing Countries

The annual international training course in geothermal energy was held at Kyushu University with Prof. Onodera of the Faculty of Engineering of the University as the course leader. This course is intended for training 10 to 20 engineers invited from developing countries on technology for development of geothermal energy for about 90 days annually, and the year of 1979 fell in the 10th session. The participants in the training course for 1979 came from the following countries: Bolivia, Chile, Colombia, Costa Rica, Egypt, India, Indonesia, Iran, Kenya, Peru, the Philippines, Thailand, Turkey, and Venezuela.

Table 1 Operation Records for Geothermal Power Plants in Japan

Power Plant		Installed Capacity (MW)	Licensed Capacity (MW)	Total Output (MWh)*1	Maximum Output (MW)*2	Operation Factor (%)*3	Load Factor (%)	Remarks
Matsukawa	(1966)	22	22	175,808	22.4	95.6	89.5	Japan Metals & Chemicals Co., Ltd.
Otake	(1967)	12.5	12.5*4	52,722	11.9	92.9*5	50.6	Kyushu Electric Power Co., Inc.
Onuma	(1974)	10	8.6	62,440	8.2	95	86.9	Mitsubishi Metal Co., Ltd.
Onikobe	(1975)	25	12.5	62,084	9	95	78.7	Japan Electric Power Development Co., Ltd.
Hatchobaru	(1977)	50	48*6	329,356	48.1	99.2	78.2	Kyushu Electric Power Co., Inc.
Kakkonda	(1978)	50	50	381,919	51	92	85.4	Steam Generation: Japan Metals & Chemicals Co., Ltd. Power Generation: Tohoku Electric Power Co., Inc.

Notes: *1 Total output is for January-December period of 1979.

*2 Maximum output is the maximum value of one hour average.

*3 Operation factor is $\frac{\text{operating days}}{365} \times 100$

*4 Licensed capacity was changed from 11 MW to 12.5 MW on November 27, 1979

*5 Periodic repairs from October 1 to 20, 1979

*6 Change in licensed capacity: 1979, Mar. 23: from 27 to 35 MW
Apr. 26: from 35 to 44 MW
June 28: from 44 to 48 MW
1980, Mar. 14: from 48 to 50 MW
Apr. 1: from 50 to 52 MW

Matsukawa is #119 in Figure 3; Otake is #172; Onuma is #19; Onikobe is #123; Hatchobaru is #172; Kakkonda is #119.

Table 2 Geothermal Power Plants under Construction or Planned in Other Countries

Country	Name of Power Plant	Number of Units	Total Capacity (MW)	Remarks (Enterprises which have received orders for equipment)
U.S.A.	The Geysers	5	554.5	3 units of 5 units to Tokyo Shibaura Electric Co., Ltd.
	Brawley	1	10	Mitsubishi Heavy Industries Co., Ltd.
	Heber	1	50	Mitsubishi Heavy Industries Co., Ltd.
	No. Cal. Pow. Auth.	2	110	Fuji Electric Co., Ltd.
Mexico	Cerro Prieto	1	30	Mitsubishi Heavy Industries Co., Ltd.
El Salvador	Ahuachapan	1	40	Fuji Electric Co., Ltd.
Iceland	Krafla	1	30	Mitsubishi Heavy Industries Co., Ltd.
Philippines	Tiwi	2	110	Tokyo Shibaura Electric Co., Ltd.
	Makiling	3	111.2	Mitsubishi Heavy Industries Co., Ltd.
	Tonganan	4	115.5	Mitsubishi Heavy Industries Co., Ltd.
Kenya	Alkaria	1	15	Mitsubishi Heavy Industries Co., Ltd.
Portugal	Azores	1	3	Mitsubishi Heavy Industries Co., Ltd.

Fig. 1 MAP of JAPAN

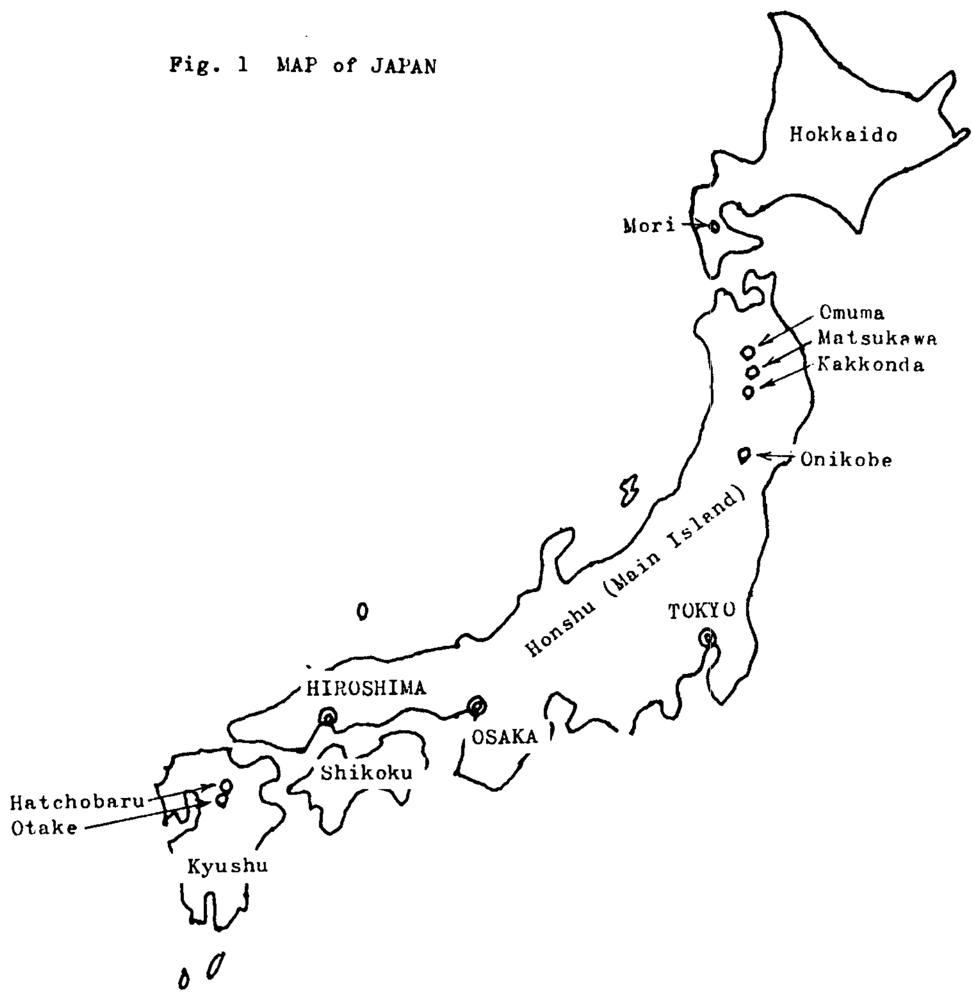
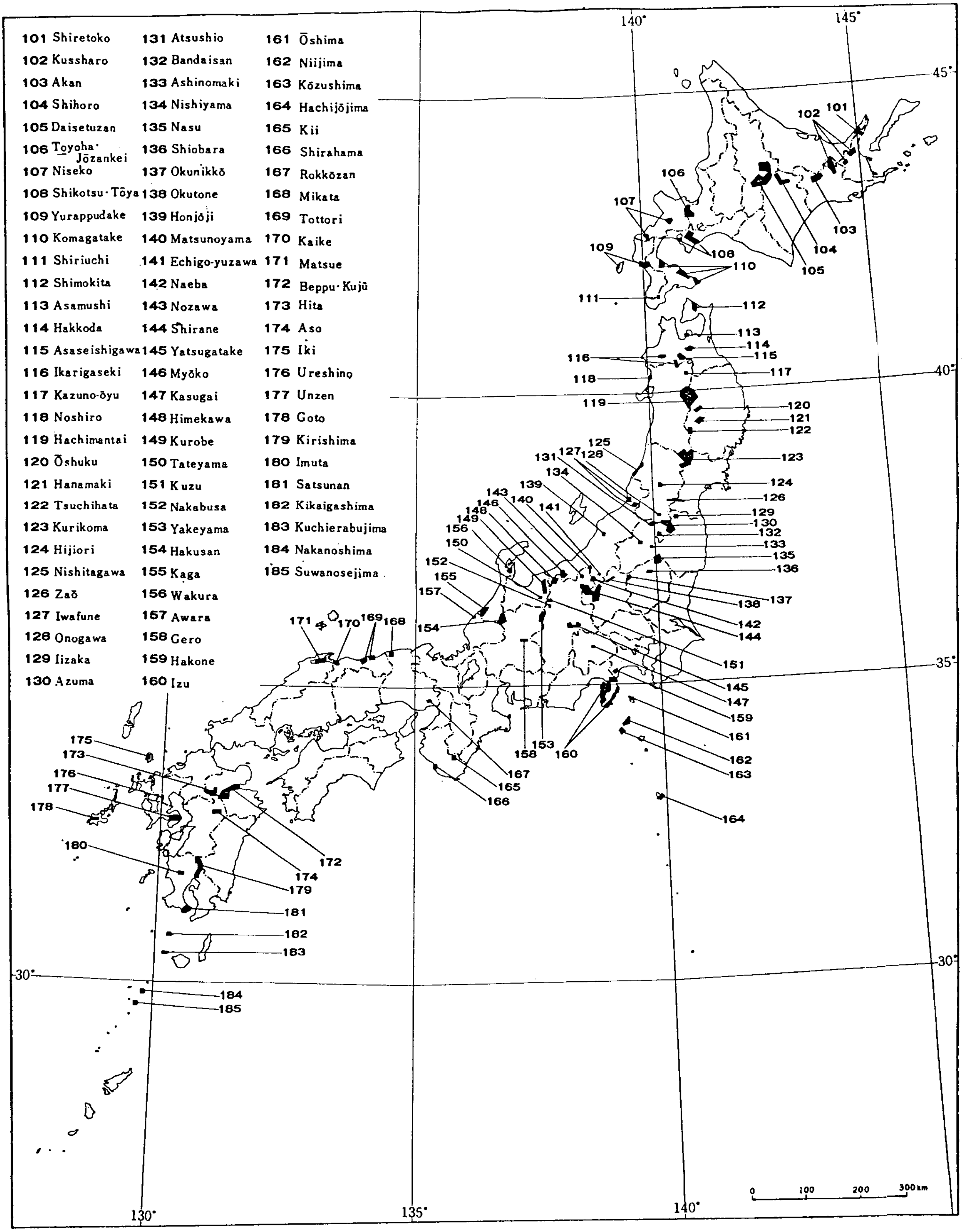


Figure 2 Geothermal Areas in Japan, from 1977 Geological Survey



WORLDWIDE GEOTHERMAL POWER PLANTS: STATUS AS OF JUNE 1980

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Introduction There are 100 geothermal power units now in operation throughout 12 countries, with a total installed capacity of just over 2110 MW. The average unit thus is rated at 21.1 MW. Newer units may be broadly classified as follows: (a) wellhead units of less than 5 MW; (b) small plants of about 10 MW; (c) medium plants of 30-35 MW; (d) large plants of about 55 MW; and (e) complexes typically consisting of several 55 MW units in a large geothermal field. There is a trend toward turbine units of the double-flow type with a 55 MW rating, used either alone or in a tandem-compound arrangement giving 110 MW in a single power house. This is particularly evident at The Geysers field in California. Double-flash units (separated-steam followed by a surface flash) are suited to high quality reservoirs having high temperature, high steam fractions at the wellhead, and low scaling potential. Single-flash units (separated steam) may be called for where scaling by the spent brine is a potential problem for the liquid disposal system. Binary plants are being used for some very low temperature reservoirs, particularly in the People's Republic of China, albeit in extremely small units. A large-scale pilot plant of the binary type is being planned for the Imperial Valley of California.

Summary Table 1 contains a summary of the geothermal power plants installed around the world by country.

Table 1. Summary of Installed Geothermal Power Plants

Country	No. of Units	Installed Capacity, MW
China	9	5.186
El Salvador	3	95
Iceland	2	32
Indonesia	1	0.25
Italy	37	420.6
Japan	7	166
Mexico	4	150
New Zealand	14	202.6
Philippines	6	224.2
Turkey	1	0.5
U.S.S.R.	1	5
United States	15	809.2
		2110.536 MW

It may be seen that the U.S. holds the lead in installed capacity. Futhermore, the average unit size in the U.S. is about 54 MW, whereas in Italy, which operates the most units, the average size is only 11 MW. It should also be pointed out that the actual capacities of the units in Italy and in New Zealand, the fourth largest geothermal power country, are well below the installed values owing to decline of the reservoirs. Italian gothermal plants have been operating since 1904 and those in New Zealand since 1958. The most rapid gains are taking place in the Philippines, now the third largest in installed capacity, where 220 MW have been brought on-line within the last 16 months.

Now we shall present more detailed tabular surveys of the geothermal plants in each country along with a few brief remarks in each case.

China (See Table 2) We have recently learned about the geothermal activities in the People's Republic of China. A more thorough study is contained in a companion paper in these Proceedings by this author.

Table 2. CHINA

Plant	Year	Type	Rating, MW
Fengshun			
Unit 1	1970	1-Flash	0.086
Unit 2	1971	Binary: i-C_4H_{10}	0.200
Unit 3	1979	n.a.	0.250
Huailai	1971	Binary: C_2H_5Cl; C_4H_{10}	0.200
Wentang	1971	Binary: C_2H_5Cl	0.050
Huitang	1975	1-Flash	0.300
Yingkou	1977	Binary:Freon; C_4H_{10}	0.100
Yangbajing			
Unit 1	1977	1-Flash	1.0
Unit 2	1979	1-Flash	3.0
		Total, installed	5.186 MW

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El Salvador (See Table 3) Ahuachapán is the site of one of the most successful flash-steam plants in the world. It is the subject of a companion paper in these Proceedings by this author.

Iceland (See Table 4) Only two units are in operation, one at Krafla and one at the district heating plant at Svartsengi. The 30 MW unit at Krafla is a double-flash plant that has experienced considerable difficulty in maintaining an adequate and stable flow of geofluid. The active seismic nature of the field has contributed to the operational problems. The plant can produce only a fraction of its rated capacity. Two 1 MW steam turbines are incorporated into the Sudurns district heating plant at Svartsengi near Grindavik on the Reykjanes peninsula in southwestern Iceland. The turbines receive a portion of the steam flashed and separated from the hot geothermal wells, the bulk of the steam being supplied to a number of heat exchangers to raise the temperature of water from cold wells. The power is used on site to run pumps and other station auxiliaries.

Italy (See Table 5) All of Italy's geothermal electricity comes from dry steam reservoirs in three regions: Larderello, Travale, and Monte Amiata. Considerable exploration is underway to locate and define the liquid-dominated reservoirs that exist in the country. It is estimated that about 2000 MW may eventually come from liquid-dominated fields. The best areas lie on the southwestern side of the Italian peninsula and include the regions: Monti Volsini, Monti Cimini, Monti Sabatini, Colli Albani, Roccamonfina, Campania Ovest and Monte Vulture.

Japan (See Table 6) The first geothermal plant in Japan was the dry steam plant at Matsukawa. Since then several plants have been built on liquid-dominated reservoirs, most of these being of the flash-steam type. Two experimental binary plants were built, tested and dismantled. One of these, at the Otake field, was of the "steam-assist" type that used an advanced, multistage flash heater to generate saturated isobutane vapor for use in a radial-inflow turbine. The waste heat rejection system incorporated a dry cooling tower with a liquid assist. The other plant at Mori (Nigorikawa) on the northern island of Hokkaido employed refrigerant-114 as the working fluid, used an axial flow turbine, and more conventional shell-and-tube heat exchangers at both the hot and cold sides of the cycle. The newest plant in Japan is a small 1 MW unit to supply the needs of the Suginoi resort hotel at Beppu on the island of Kyushu. This is in a world famous hot springs area that was the

Table 3. EL SALVADOR

Plant	Year	Type	Rating, MW
Ahuachapán			
Unit 1	1975	1-Flash	30
Unit 2	1976	1-Flash	30
Unit 3	1980	2-Flash	35
Berlín	Future	Flash	100 (Est.)
Chinameca	Future	Flash	100 (Est.)
Chipilapa	Future	Flash	50 (Est.)
San Vicente	Future	Flash	100 (Est.)
	Total, Installed		95 MW

Table 4. ICELAND

Plant	Year	Type	Rating, MW
Námafjall	1969	1-Flash	3*
Krafla			
Unit 1	1978	2-Flash	30
Unit 2	Future	2-Flash	30
Svartsengi	1978	1-Flash	2
	Total, Installed		32 MW

*Dismantled after earthquake damage.

Table 5. ITALY

Plant*	Year	Rating, MW
Larderello		
Unit 2	c.1946	69.0
Unit 3	1969	120.0
Gabbro	1960	15.0
Castelnuovo	n.a.	50.0
Serrazzano	n.a.	47.0
Lago 2	n.a.	33.5
Sasso Pisano	n.a.	15.7
Monterotondo	n.a.	12.5
Travale	1973	15.0
Piancastagnaio	1969	15.0
Others (8 units)	-	27.9
	Total, Installed	420.6 MW

*All plants use dry steam; turbines are either condensing or noncondensing.

site of earliest Japanese attempts to harness geothermal energy in the 1920's. Geothermal plants in Japan must meet very tough environmental restrictions owing to their location in scenic national parks.

Mexico (See Table 7) Fifteen years after the beginning of the exploration of the Cerro Prieto field, the first power unit started producing electricity. Now there are four units generating 150 MW in a very reliable fashion, with a fifth unit of 30 MW under construction. This will complete the development of Cerro Prieto I. Additional development will necessitate the construction of a new plant complex in another part of the field. Some of the electricity from the plant is being sold to the U.S. for use in communities in southern California.

New Zealand (See Table 8) Although New Zealand was the first country to exploit successfully liquid-dominated reservoirs, it has not brought a new unit on-line since 1963 when the last unit started up at Wairakei. The installed capacity there is 192.6 MW, but it has never reached that value. Peak power was 173 MW in 1964-65; currently it produces about 145 MW and it is expected to generate about 125 MW indefinitely. A new plant named Ohaki at the Broadland-Ohaki field has been in the planning stage for a long time but various institutional impediments have caused delays in its implementation. The plan is to construct two 50 MW double-flash units at the site with an additional 50 MW possibly for the future. It appears that 1984 is the most optimistic date for inauguration of the first unit.

Philippines (See Table 9) Geothermal development is proceeding full tilt in the Philippines. Two sites, Makiling-Banahaw and Tiwi, both on the northern island of Luzon, are the locations of large power complexes. Already two units of 55 MW each are operating at both of these sites. [Personal communication, Dr. L. Rivero.] The installed capacity at each plant is expected to double by 1982. On the island of Leyte a 3 MW wellhead unit has been running since 1977 taking steam from one well in the Mahiao area. Three 37.5 MW are planned for this site. Although double-flash units will be specified, it is likely that initially they will be operated as single-flash units owing to uncertainties about the economics, and potential problems with silica deposition in the waste brine.

Table 6. JAPAN

Plant	Year	Type	Rating, MW
Matsukawa	1966	Dry Steam	20
Otake	1967	1-Flash	10
Onuma	1973	1-Flash	10
Onikobe	1975	1-Flash	25
Hatchobaru	1977	2-Flash	50
Kakkonda	1978	1-Flash	50
Otake Pilot*	1978	Binary: $i\text{-}C_4H_{10}$	1
Mori Pilot*	1978	Binary: R-114	1
Suginoi (Hotel)	1980	1-Flash	1
Nigorikawa	1981	1-Flash	50
Kuzeneda	Future	Flash	50 (Est.)
Kumamoto	Future	2-Flash	55 (Est.)
	Total,	Installed	166 MW

*Tests Complete; Plants Dismantled.

Table 7. MEXICO

Plant	Year	Type	Rating, MW
Cerro Prieto I			
Unit 1	1973	1-Flash	37.5
Unit 2	1973	1-Flash	37.5
Unit 3	1979	1-Flash	37.5
Unit 4	1979	1-Flash	37.5
Unit 5	1982	2-Flash	30.0
Cerro Prieto II	Future	Flash	110 (Est.)
	Total,	Installed	150 MW

Table 8. NEW ZEALAND

Plant	Year	Type	Rating, MW
Wairakei			
Station A	1958-1962	Multiflash	102.6
Station B	1962-1963	2-Flash	90.0
Kawerau	1961	1-Flash	10.0
Ohaki	1984	2-Flash	100.0
		Total, Installed	202.6 MW

Table 9. PHILIPPINES

Plant	Year	Type	Rating, MW
Tongonan			
Wellhead Unit	1977	1-Flash	3.0
Unit 1	1980	2-Flash	37.5
Unit 2	Future	2-Flash	37.5
Unit 3	Future	2-Flash	37.5
Makban (Makiling Banahaw)			
Wellhead Unit	1977	1-Flash	1.2
Unit 1	1979	2-Flash	55.0
Unit 2	1979	2-Flash	55.0
Unit 3	1981	2-Flash	55.0
Unit 4	1982	2-Flash	55.0
Tiwi			
Unit 1	1979	2-Flash	55.0
Unit 2	1979	2-Flash	55.0
Unit 3	1980	2-Flash	55.0
Unit 4	1980	2-Flash	55.0
Other Sites	Future	Flash	775
		Total, Installed	224.2 MW

United States (See Table 10) The largest geothermal power complex in the world is at The Geysers where three utilities are involved in several projects. The Pacific Gas and Electric Company now operates 14 units (Nos. 1-13 and 15), accounting for 798 MW. When unit 14 comes on-line later in 1980 the total will reach 908 MW. Before the end of 1984 it is planned to put an additional 660 MW on-line. The Northern California Power Agency plans to operate two units at The Geysers. Unit 2 will consist of two 55 MW turbines in a single power house and is expected in 1981. It will be followed in 1983 by a 66 MW unit. The Sacramento Municipal Utility District is moving ahead with SMUDGEO no. 1, a 55 MW unit scheduled for commercial start-up in December 1983. In addition the California Division of Water Resources has plans to build two plants, each of 55 MW, at Bottle Rock and South Geysers, with expected start-up dates in 1983. Stringent air pollution regulations make it necessary to install hydrogen sulfide abatement systems on all plants. Up-stream treatment will most likely be required to avoid air quality degradation during out-of-service periods when venting of steam takes place. Reinjection of condensate is standard practice.

Table 10. UNITED STATES

Plant	Year	Type	Rating, MW
The Geysers			
PG&E 1-12,15	1960-1979	Dry Steam	663
PG&E 13,14	1980	Dry Steam	245
PG&E 16-21	1982-1984	Dry Steam	660
NCPA No. 1	1983	Dry Steam	66
NCPA No. 2	1981	Dry Steam	110
SMUDGEO 1	1983	Dry Steam	55
Bottle Rock	1983	Dry Steam	55
South Geysers	1983	Dry Steam	55
East Mesa - Magmamax	1980	Dual Binary: C_3H_8; i-C_4H_{10}	11.2
East Mesa - SDG&E	1980,82	1- and 2-Flash	48
Brawley - SCE	1980	1-Flash	10
Niland - SCE	1982	1-Flash	10
Niland - SDG&E	1982	Flash	50
Heber - SCE	1982	2-Flash	50
Heber - SDG&E	Future	Binary: mixt. i-C_5H_{12}; i-C_4H_{10}	50
Westmorland	Future	2-Flash	50
Raft River, Idaho	1980	Double Binary: i-C_4H_{10}	5
Puna, Hawaii	1980	1-Flash	5
Baca No. 1, New Mexico	1982	1-Flash	50
Roosevelt H.S., Utah	Future	Flash	55
Desert Peak, Nevada	Future	Flash	50
		Total, Installed	809.2 MW
		Total, Projected	2353.2 MW

Although the liquid-dominated portion of the field has yet to be defined or even characterized, it is expected that about 700 MW could be generated from that part of the field by 1990. In this regard it should be noted that it takes about 8 kg/h (18 lbm/h) of dry steam to generate 1 kW of electric power, about one-quarter of which ends up as condensate to be reinjected (assuming a shell-and-tube condenser is used). On the other hand a flash-steam plant requires about 45 kg/h (100 lbm/h) of geofluid per 1 kW of power, of which about 87% must be reinjected. Thus, to generate the same power, a flash plant must reinject almost 20 times more liquid than a dry steam plant.

From Table 10 it can be seen that a variety of projects are under way in the Imperial Valley of southern California, which according to some estimates holds the potential for about 9000 MW. Resources in at least five other states are expected to be exploited for power in the near future.

Other Countries (See Table 11) Of the countries listed only the Soviet Union has a plant of any size (5 MW) in operation. Indonesia is beginning to develop its gigantic geothermal potential by means of small wellhead units. Turkey has a tiny wellhead generator at Kızıldere, but severe scaling has prohibited any further development there. The Olkaria field in the Rift Valley of Kenya in east Africa seems to be a good prospect, and plans are moving ahead for the Kenya Electric Power Corporation to build a 15 MW plant. A "total energy" system is planned for the Portuguese island of São Miguel in the Azores. The geothermal energy with which the island abounds will be put to use to generate power (3 MW), provide heating and refrigeration, as well as for agricultural, horticultural and aquacultural uses.

Table 11. OTHER COUNTRIES

Country	Plant	Year	Rating, MW
Chile	El Tatio	Future	15
Costa Rica	Miravalles	Future	40 (Est.)
Guatemala	Amatitlán	Future	50 (Est.)
Honduras	Pavana	Future	50 (Est.)
Indonesia	Kamojang	1978	0.25
	Kamojang	Future	100 (Est.)
	Dieng	1980	2
Kenya	Olkaria	1982	15
	Olkaria	Future	30 (Est.)
Nicaragua	Momotombo	Future	30 (Est.)
Panama	Cerro Pando	Future	30 (Est.)
Portugal (Azores)	São Miguel	1980	3.0
Turkey	Kızıldere	Future	14 (Est.)
USSR	Pauzhetka	1967	5
	Other Sites	Future	78 (Est.)

Acknowledgements Much of the information reported in this paper was acquired during the writing of Geothermal Energy as a Source of Electricity: A Worldwide Survey of the Design and Operation of Geothermal Power Plants by the author. This was part of an effort supported by the U.S. Dept. of Energy, Div. of Geothermal Energy, C.B. McFarland, Chief - Hydrothermal Technology, through Contract EY-76-S-02-4051.A 002 to Brown University, J. Kestin, Principal Investigator. Copies of the above-mentioned book may be obtained by writing to the author. They will be distributed, free-of-charge, beginning mid-1980 as long as the supply lasts.

APPENDIX A

EPRI GEOTHERMAL RESEARCH AND DEVELOPMENT PROJECTS

RESEARCH AND DEVELOPMENT PROJECTS

Advanced Power Systems Division
Renewable Resources Systems Department

March 21, 1980

GEOTHERMAL

+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 & Electric Company. Final Report No. EPRI376 , November 1975.

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

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

RP653 - Brine Chemistry and Combined Heat/Mass Transfer: The objective is to develop an analytical capability to predict precipitation of solids and scale formation 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 codes are now being applied to case studies of facilities planned or operated at various geothermal reservoirs.

RP741 - Mobile Geothermal Fluids, Materials, and Components Test Laboratory: The objectives of this 3-year research 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 mobile laboratory facility design is complete. The chemical analysis trailer is ready for operation. 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; and Final Report No. ER1034 (Project No. RP928-4), March 1979.

RP929 - Geothermal Reservoir Assessment Techniques: The objective of this study is to develop experience with small-scale heat exchanger modules designed to simulate typical power system design. The results are expected to include: (1) benchmark process data; (2) comparison of heat transfer, scaling, and corrosion performance; (3) collection of additional scale and corrosion data for use in brine chemistry techniques for predicting scale and corrosion formation; (4) materials performance data associated with chemical cleaning of heat exchanger modules; and (5) performance of three candidate hydrocarbon working fluids. This project is funded by EPRI and DOE, with Lawrence Berkeley Laboratory acting for DOE. Colley Engineering & Constructors, Inc., is the contractor.

+ denotes that the project is completed.

RP1195 - Assessment of Critical Geothermal Technical Issues: The goal is to establish a data base useful for predicting geothermal power plant design, operation, and interaction characteristics. 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 Co.; and Colley Engineers.

RP1196 - Field Evaluation of Rotary Phase-Separator Turbine: The objective of this project is to evaluate the performance and assess the potential of separated phase, "total flow" power conversion processes for generating electricity from water-dominated geothermal resources. It involves the design and testing of a bench model hydraulic turbine subsystem, fitted to a rotary steam separator to form a flash/separator/turbine system. Biphase Energy System 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 copper sulfate scrubbing process and a heat exchanger process. The heat exchanger process is being tested at The Geysers through a cooperative effort with Pacific Gas and Electric Company. The contractors are EIC Corporation (copper sulfate method) and Coury and Associates (heat exchanger method).

RP1272 - Assessment of Economics and Technologies for Geopressure Energy Extraction: The goal of this project is to identify the most credible estimate of geopressure resources, including thermal, geohydraulic pressure, and methane. Other objectives are to identify the technical requirements for energy extraction and power conversion and to assess the adequacy of current technology, and to analyze the economics associated with geopressure development. The Southwest Research Institute is the contractor.

*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 reducing by 50 percent the outage rate due to scale accumulation.

*RP1671 - Geopressure Energy Conversion - Preferred Systems: The objective of this project is to evaluate system concepts for geopressure energy recovery, power plant design, and integration with the existing electricity supply.

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. Bechtel National Inc. is the contractor.

*RP1673 - Geothermal Technology and Economic Assessment of Advanced Power Generation: The objective of this project is to estimate the growth rate and market penetration to the year 2000 of geothermal utilization. This work involves economic modeling, assessing the probable performance and cost of emerging technologies, analyzing growth trends, and estimating market penetration.

*RP1900 - Binary Cycle Demonstration Power Plant: The objective is to demonstrate the technical maturity and the economic and environmental superiority of binary cycle conversion technology for development of moderate temperature hydrothermal resources. The objective is to be achieved by designing, constructing, and operating a 45 MWe (net) binary cycle power plant at a geothermal reservoir near Heber, California. The project is to be funded by DOE, EPRI, San Diego Gas & Electric Company, and other utilities.

* denotes that a contract is not yet signed

APPENDIX B

CONFERENCE ATTENDEES

ATTENDEES - FOURTH ANNUAL EPRI GEOTHERMAL CONFERENCE (1980)

Alt, Theodore E.	Arizona Public Service Co.	P.O. Box 21666	Phoenix, AZ	85036	602-271-2968
Anastas, George	San Diego Gas & Electric Co.	P.O. Box 1831	San Diego, CA	92112	714-235-7733
Angwin, Meredith Joan	Electric Power Research Inst.	P.O. Box 10412	Palo Alto, CA	94303	415-855-2594
Atkinson, Richard	Sierra Pacific Power Co.	P.O. Box 10100	Reno, NV	89510	702-789-4321
Awerbuch, Leon	Bechtel National, Inc.	50 Beale Street	San Francisco, CA	94119	415-768-1482
Babione, Robert A.	Coury and Associates	7625 W. 5th Avenue	Lakewood, CO	80226	303-232-3823
Barnette, Richard T.	Pacific Power & Light Co.	920 S.W. 6th Avenue	Portland, OR	97204	503-243-4314
Barr, Ron	Earth Power	P.O. Box 1566	Tulsa, OK	74101	918-587-9704
Bell, Harold	Arizona Public Service Co.	P.O. Box 21666	Phoenix, AZ	85036	602-271-2252
Blucher-Nameny, L.	Pacific Gas and Electric Co.	77 Beale Street	San Francisco, CA	94106	415-781-4211
Bos, Piet B.	Electric Power Research Inst.	P.O. Box 10412	Palo Alto, CA	94303	415-855-2165
Bouma, John	Bechtel Power Corporation	12400 E. Imperial Hwy.	Norwalk, CA	90650	213-864-6011
Brown, F. C.	EIC Corporation	55 Chapel Street	Newton, MA	02158	617-965-2710
Burke, James	Bechtel Power Corporation	50 Beale Street	San Francisco, CA	94119	415-768-0624
Cerini, Don	Biphase Energy Systems	2800 Airport Avenue	Santa Monica, CA	90405	213-391-0691
Chastaine, Alan R.	Morrison Knudsen, Inc.	P.O. Box 7808	Boise, ID	83729	208-386-6488
Cochrane, G. F.	Bechtel National, Inc.	P.O. Box 3965	San Francisco, CA	94119	415-768-5758
Cooper, A. M.	Chevron Resources Co.	P.O. Box 3722	San Francisco, CA	94119	415-894-3825
Cooper, Larry	NUS	1337 Cerro Verde	San Jose, CA	95120	415-494-7175
Cotton, Gary	San Diego Gas & Electric Co.	P.O. Box 1831	San Diego, CA	92112	
Coury, Glenn E.	Coury and Associates	7625 W. 5th Avenue	Lakewood, CO	80226	303-232-3823
Crane, George K.	Southern California Edison	P.O. Box 800	Rosemead, CA	91770	213-572-2775
Cummings, John E.	Electric Power Research Inst.	P.O. Box 10412	Palo Alto, CA	94303	415-855-2166
Dambly, Benjamin W.	J. Hilbert Anderson, Inc.	2422 S. Queen Street	York, PA	17402	717-741-0884
DeHaven, Norman	Southern California Edison	P.O. Box 800	Rosemead, CA	91770	
DiPippo, Ronald	Southeastern Mass. University		N. Dartmouth, MA	02747	617-999-8541

Doherty, John T.	Weston Geophysical	P.O. Box 550	Westborough, MA	01581	617-366-9191
Dominguez, Bernardo	CFE	P.O. Box 248	Calexico, CA	92231	903-762-2012
Duffield, Wendell	U.S. Geological Survey	345 Middlefield Road	Menlo Park, CA	94025	
Durning, Bob	Biphase Energy Systems	2800 Airport Avenue	Santa Monica, CA	90405	213-391-0691
Dziegiel, Henry T.	L.A. Dept. of Water & Power	P.O. Box 111	Los Angeles, CA	90012	213-481-7728
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Fick, T. R.	Bechtel National, Inc.	P.O. Box 3965	San Francisco, CA	94119	415-768-5758
Finney, John	Pacific Gas and Electric Co.	77 Beale Street	San Francisco, CA	94106	415-781-4211
Flower, Jack E.	Gibbs & Hill, Inc.	1754 Technology Drive	San Jose, CA	95110	408-280-7091
Forster, Leslie L.	Ecolaire Condenser, Inc.	P.O. Box 2327	Lehigh Valley, PA	18001	215-866-9544
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Guiza, Jorge	Instituto de Invest. Electricas	Justo Sierra y Herreros 2098	Mexicali, B.C.	Mexico	
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Henry, Paul	NUS Corp.	14011 Ventura Blvd.	Sherman Oaks, CA	91423	213-783-0254
Hinrichs, Tom	Magma Power Co.	P.O. Box 2082	Escondido, CA	92025	714-743-7008
Holm, John	Rotoflow Corp.	2235 Carmelina Avenue	Los Angeles, CA	90064	213-477-3083
Holt, Ben	The Ben Holt Co.	201 South Lake Avenue	Pasadena, CA	91101	213-684-2541
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Nealy, Carson L.	Rockwell International	8900 DeSoto Avenue	Canoga Park, CA	91304	213-341-1000
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Pullen, T. K.	Ecolaire Inc.	110 Sutter Street	San Francisco, CA	94104	415-433-1561
Pundyk, Joseph M.	PFR Engineering Systems, Inc.	4676 Admiralty Way	Marina del Rey, CA	90291	213-822-8620
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Ridgway, Jr., J. R.	Houston Lighting and Power Co.	P.O. Box 1700	Houston, TX	77001	713-481-7597

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Saidani, Achour	Ministry of Energy	80 Avenue Ghermoul	Algiers	Algeria	663300
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Turpin, Frank	Morrison Knudsen	P.O. Box 7808	Boise, ID	83729	208-386-5612
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Welch, Harry J.	Transamerica Delaval Inc.	P.O. Box 8788	Trenton, NJ	08629	609-890-5420
Whitbeck, J. F.	EG&G	P.O. Box 1625	Idaho Falls, ID	83415	208-526-1879
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Winkler, William R.	Stone & Webster Engr. Corp.	245 Summer Street	Boston, MA	02107	617-973-8928
Ziomek, N. L.	Pacific Gas and Electric Co.	77 Beale Street	San Francisco, CA	94106	415-781-4211