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GEOTHERMAL POWER PLANTS OF THE
UNITED STATES: A TECHNICAL SURVEY
OF EXISTING AND PLANNED INSTALLATIONS

By
Ronald DiPippo

April 1978

Work Performed Under Contract No. EY-76-S-02-4051

Division of Engineering
Brown University
Providence, Rhode Island

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

MASTER

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A Technical Survey of Existing and Planned Installations

by

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Contract EY-76-S-02-4051.A001

Abstract

This report traces the development of geothermal energy as a source of electric power in the United States. A thorough description is given of The Geysers geothermal power project in northern California. The recent efforts to exploit the hot-water resources of the Mexicali-Imperial Rift Valley are described. Details are given concerning the geology of the several sites now being used and for those at which power plants will soon be built. Attention is paid to the technical particulars of all existing plants, including wells, gathering systems, energy conversion devices, materials, environmental impacts, economics and operating characteristics. Specifically, plants which either exist or are planned for the following locations are covered: The Geysers, CA; East Mesa, CA; Heber, CA; Roosevelt Hot Springs, UT; Valles Caldera, NM; Salton Sea, CA; Westmorland, CA; Brawley, CA; Desert Peak, NV; and Raft River, ID. The growth of installed geothermal electric generating capacity is traced from the beginning in 1960 and is projected to 1984.

Acknowledgements

The author wishes to thank the following people for their help in the preparation of this report:

C. B. McFarland, DOE/DGE, Project Manager
J. Kestin, Brown University, Principal Investigator
D. N. Anderson, Geothermal Resources Council
B. J. Cossette, Pacific Gas and Electric Company
J. H. Eskesen, General Electric Company
J. P. Finney, Pacific Gas and Electric Company
T. C. Hinrichs, Imperial Magma
J. T. Kuwada, Rogers Engineering, Inc.

The author carried out this project while on sabbatic leave from Southeastern Massachusetts University, North Dartmouth.

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1. History of geothermal energy usage

"The most important factors having been worked out - a successful method of drilling into high pressure natural steam bearing areas and a successful method established for the control of steam thus produced - and with a solution of the minor factors now assured, it would appear that the successful commercial use of this natural resource is on the eve of accomplishment at The Geysers."

These words were written by H. N. Siegfried, an engineer for the Southern Sierras Power Company, in a 1925 report to A. B. West, President and General Manager of the same company [Siegfried, 1925]. Thirty-five years later the first commercial geothermal power plant came on-line at The Geysers.

At the time of Siegfried's comment, there had been six steam wells drilled, all of them producers, flow tests had been carried out, and estimates of power output had been made. His report contained a layout of a simple power plant with three 10,000 kW turbines. The Geysers Unit 1 produced 11,000 kW from a single turbine, starting on September 25, 1960.

The history of geothermal energy in the United States dates back over one hundred and thirty years. Explorer-surveyor William Bell Elliott is credited with discovering The Geysers natural steam field while bear-hunting in April 1847 between Cloverdale and Calistoga [Lengquist and Hirschfeld, 1976]. The awesome sight of clouds of water vapor shooting high into the air accompanied by the roar of escaping steam and the smell of odorous sulfur fumes led Elliott to believe he had discovered the very gates to the Inferno.

The region was exploited at first as a tourist attraction boasting the alleged therapeutic qualities of the hot fluids. The resort was advertised as "The Eighth Wonder of the World", "Nature's Gift to California", and "The Tourists' Paradise". The register of the resort hotel contained, among others,

the names of Theodore Roosevelt, William McKinley, Ulysses Grant and Mark Twain.

Following the passing of the resort as a popular attraction, an attempt was made in the early 1920s to develop its potential for electric power production. John D. Grant, a rock, gravel and cement contractor from Healdsburg, not far from The Geysers, deserves the credit for initiating the development of The Geysers [Siegfried, 1925]. Grant secured the services of J. D. Galloway, a San Francisco consulting engineer, who supervised the technical aspects of the work. The drilling was done by Fred Stone, part-owner of the Doheny-Stone Drilling Company, who used his invention called the "Hydril", a hydraulically-controlled drilling head that could control the flow of the well fluid through the casing annulus from the wellhead [Anderson and Hall, 1973].

Large quantities of underground steam were tapped with relatively shallow wells. Eight wells were drilled to depths of between 47 m (154 ft) and 194 m (363 ft). The steam was used to power a 250 kW generator driven by a reciprocating, noncondensing engine. Further power development at that time, however, was not carried out. Although the major technical obstacles to the use of geothermal energy seemed to have been overcome, geopower plants would have had to compete against hydroelectric plants that were appearing throughout the same areas where geothermal energy was present. Furthermore, the 1920s 1930s and 1940s were the years for very rapid growth of the fossil fuel industry, and oil and gas were both plentiful and relatively inexpensive.

Thus the potential of The Geysers lay unexploited until B. C. McCabe, a Los Angeles lumber merchant with no engineering education and no prior experience in the power industry, decided to invest in the site in the early 1950s. He leased 14.6 km² (3620 acres) from The Geysers Development Company, established a company called Magma Power Co., and drilled his first well in 1955.

The well was called Magma No. 1; it was 249 m (817 ft) deep and produced 68 Mg/h (150,000 lbm/h) of dry steam at a wellhead pressure of 790 kPa (114 lbf/in²).

McCabe joined forces with Dan A. McMillan, Jr. of Thermal Power Company and together they completed six wells by 1957, ranging in depth from 161 m (527 ft) to 431 m (1414 ft). They signed a contract on October 30, 1958 with the Pacific Gas and Electric Company (PG&E) which obligated Magma-Thermal to supply steam at a flow rate of 107 Mg/h (235,000 lbm/h) and at a pressure of 790 kPa (114 lbf/in²) to the strainer inlet of a 12,500 kW turbine-generator [Lengquist and Hirschfeld, 1976].

In 1967 the Union Oil Company of California joined Magma-Thermal in the development of the geothermal field. A total of about 61 km² (15,000 acres) is under lease. The U.S. Department of the Interior has classified an additional 668 km² (165,000 acres) surrounding The Geysers as a Known Geothermal Resource Area (KGRA).

In the early days of geothermal energy discovery in the United States, several other areas besides The Geysers were explored. Most of these were areas which appeared to be promising because of surface manifestations such as steam vents, hot springs, boiling mud pots, etc. Potential sites in the Imperial Valley such as Niland and Mullet Island (Salton Sea) were studied and drilled, as early as 1927. It is interesting to note that Fred Stone, who carried out the drilling, reported [Anderson and Hall, 1973] that the wells at the Salton Sea encountered gas (probably carbon dioxide), considerable steam, water and a large quantity of 'slush'. Although the wells were good steam producers, the slush caused a number of problems. These problems, which Stone believed would clear up in time, persist to the present. The geothermal brines of the Salton Sea contain 250,000-300,000 ppm of total

dissolved solids [Austin, et al, 1977], and the utilization of these fluids remains one of the major unsolved problems in geothermal energy in the United States.

A general problem that faced nearly all geothermal regions was their remoteness. This meant that expensive transmission lines would have to be constructed to transmit the power from geothermal areas to populated areas. Although the population of the western United States has grown considerably during the past fifty years, this economic factor still plays a role in the development of the geothermal resources of the country.

2. The Geysers geothermal power project - Sonoma and Lake Counties, CA

The largest geothermal electric power complex in the world is located at The Geysers in Sonoma County of northern California. The Pacific Gas and Electric Company (PG&E) produces over 500 MW at the site with over 400 MW of additional capacity under construction, and intends to install an additional 220 MW by 1982. The present proved capacity of The Geysers exceeds 2000 MW.

2.1. Geology

The Geysers is one of several areas of hot springs and fumaroles which occur along a section of a long fault zone in the Mayacmas Mountains in northern California. The geothermal reservoir is of the vapor-dominated type and extends over an area $21.5 \text{ km} \times 8.6 \text{ km}$ ($13.3 \text{ mi} \times 5.3 \text{ mi}$), bounded by the Mercuryville fault zone on the southwest and the Collayomi fault zone on the northeast [Donnelly, et al, 1976]. The drilled area covers over 50 km^2 (12,350 acres) in an $11.2 \text{ km} \times 4.5 \text{ km}$ ($7 \text{ mi} \times 2.5 \text{ mi}$) strip lying roughly between the Big Sulphur Creek in Sonoma County and the border between Sonoma and Lake Counties.

The Mayacmas Mountains, a post-Pliocene uplift, are formed of an internal structure that is of differentially uplifted fault blocks which are tilted $30\text{-}40^\circ$ to the northeast. The majority of the faults dip steeply to the southwest, and vertical displacements along individual blocks range from 1.5 - 3 km (0.9 - 1.9 mi). Surface rocks are from the Jurassic to Cretaceous periods and are of marine sediments from both shallow and deep depositional environments [Reed and Campbell, 1975]. A schematic geological cross-section, drawn northeast and perpendicular to its major structural trend, is shown in Fig. 1 [McNitt, 1965].

The precise nature of the hydrothermal reservoir and the exact mechanism for the production of steam in The Geysers field remain a subject of

controversy. The source of the thermal energy is believed to be a magmatic intrusion which lies at about 10 km (32,800 ft). The steam-producing areas are highly fractured regions with near-vertical orientation. The fractures occur in hard, dense graywacke (a sandstone), and steam is found in two depth ranges: a shallow zone at 300-600 m (984-1968 ft) and a deep zone at 1500-3000 m (4920-9840 ft) [Reed and Campbell, 1975].

It is known, furthermore, that the vapor-dominated reservoir is characterized by a pressure that is far less than the hydrostatic pressure and which extends to depths of at least 3 km (9840 ft). The pressure anomaly is so drastic that at a depth of about 3 km (9840 ft) the reservoir pressure is only 3.5 MPa (500 lbf/in²), whereas it is 30 MPa, 4300 lbf/in² at a horizontal distance of merely 0.8 km (2600 ft) away from the reservoir.

It has been proposed [White, et al, 1971; Truesdell and White, 1973] that the presence of the vapor-dominated zone is the result of the boiling of a deep water table, and the pressure anomaly is preserved by a seal of minerals at the boundary caused by the deposition of solids from the geothermal fluid, in particular calcite (CaCO₃) and anhydrite (CaSO₄).

Opponents of this view argue [Weres, et al, 1977] that the water table would need to fall by at least 2 km (6560 ft) to account for the size of the vapor-dominated region. Furthermore, it has been shown [Witherspoon, 1977] that there is insufficient volume in the reservoir to contain only steam in the quantities required to explain the observed production from the field. An alternate model, thus, is one in which the pores or fractures in the reservoir contain liquid as well as vapor. In this model, the liquid may even be at relatively shallow depths, having been sealed in pores that have been closed by movements of elements of the fault zone. It is speculated [Witherspoon, 1977] that the liquid water is of meteoric origin (i.e., rain-water) at least 50 years old.

Figure 2 is an artist's impression of the steam field at The Geysers [PG&E News Bureau (A)].

2.2. Steam wells and gathering system

Approximately 175 wells have been drilled at The Geysers, with 75 of these actively delivering steam to the first eleven units having a total installed capacity of 502 MW. Approximately 15 wells are needed to support a typical 110 MW unit. A steam well will produce 34 - 159 Mg/h (75,000 - 350,000 lbm/h) at a wellhead pressure of 960 kPa (140 lbf/in²). A steam flow rate of 91 Mg/h (200,000 lbm/h) may be taken as typical. The closed-in pressure is about 3.4 MPa (490 lbf/in²) and the corresponding temperature is 240°C (465 °F), with a specific enthalpy of 2800 kJ/kg (1204 Btu/lbm).

A combination of mud and air drilling is used, with mud being used for the larger portions of the wells (dia. > 317.5 mm (12.5 in)). Although air drilling is faster since the cuttings are removed more quickly from beneath the drill bit, it can only be used in the smaller diameter sections where the seepage of liquid into the hole is not a serious problem. A typical casing program is shown in Fig. 3 [Reed and Campbell, 1975]. Mud is used down to about 600 m (1968 ft), mud or air (depending on the presence or lack of groundwater) from there to 1370 m (4494 ft), and air from the top of the fractured graywacke to the bottom of the well. Table 1 lists the characteristics of the two methods of drilling wells. Table 2 gives the composition of the drilling mud used by Union-Magma-Thermal.

The spacing between wells is determined by economics and the physical setting in the field. Many of the drill pads are built on filled land owing to the rugged terrain. The density of wells differs from company to company, with Union-Magma-Thermal drilling 1 well/8 ha (1 well/20 acres) and Aminoil drilling 1 well/16 ha (1 well/40 acres) [Weres, et al, 1977].

Directional drilling is used to drill under areas that would otherwise be inaccessible, to intersect nearly vertical fissures, to intercept a blown-out well so as to control the blow-out, to reduce the number of pads required to drill a number of wells, and to simplify the steam gathering system necessary to transmit the steam to the power house. Directional drilling with air is accomplished by means of a wedge placed downhole which deflects the bit off to the side. The wedge is called a whipstock and is capable of producing a deflection of $6.6 - 8.2^\circ/100 \text{ m}$ ($2 - 2.5^\circ/100 \text{ ft}$). It is relatively easy to achieve a lateral displacement of 400 m (1310 ft) in a well of 1500 m (4920 ft) nominal depth. Since it may take about one-third longer to drill a directional well compared to a vertical well of the same depth, directional drilling is more costly than vertical drilling. The added drilling costs are partially compensated by savings resulting from the consolidation of wellhead equipment at a single site since only a small additional area is needed to accommodate up to six wellheads compared to a single wellhead which requires between 0.4 - 1.2 ha (1 - 3 acres).

A typical gathering system for a 55-MW unit consists of a network of carbon steel pipes, starting with 254 mm (10 in) O.D. pipes at the wellheads and ending with 914 mm (36 in) O.D. pipes of 9.5 mm (0.375 in) wall thickness at the power house. Usually seven wells must be connected to the system to supply the required 450 t/h (10^6 lbm/h) of steam. A centrifugal axial separator is situated on the steam line at each well to remove particulate matter that can cause erosion of the steam pipes and turbine blades [Matthew, 1975].

A map of The Geysers area is shown in Fig. 4 [Dan, et al, 1975] from which the locations of the first 15 units may be seen. The steam pipelines are not longer than about 2 km (6560 ft) so as to control the loss of availability of the steam from the wellhead to the turbine.

2.3. Unit 1

The first two units of The Geysers project are housed in a single power house located adjacent to Big Sulphur Creek, not far from The Geysers Resort. An aerial photograph of the plant site is shown in Fig. 5 [PG&E News Bureau (B)]; an elevation drawing of the unit including the cooling tower is given in Fig. 6 [Bruce, 1961]; a heat balance diagram for Unit 1 is shown in Fig. 7 [Bruce, 1961]; Table 3 lists the technical particulars for the major mechanical elements of the unit. Although the maximum capacity of the unit is 12.5 MW, it is usually operated at 11 MW to allow for flexibility in load factor.

The steam turbine for Unit 1 is a reconditioned General Electric machine of 1924 vintage which originally was in service at a PG&E plant in Sacramento, CA. The original version had nine stages and was designed for steam at 1.31 MPa (190 lbf/in²) and 248°C (478°F) with exhaust at 5.1 kPa (1.5 in Hg). The first three stages were removed, the control valves were replaced by two butterfly valves of 152 mm (6 in) and 254 mm (10 in), and the last two stages of buckets were rebuilt of 11 - 13% chrome steel. Other modifications were made to allow the turbine to accommodate the geothermal steam conditions and the higher back pressure [Bruce, 1961].

2.4. Unit 2

This unit came on line in 1963, three years after the first unit and shares the same power house with Unit 1. The arrangement of the unit is similar to the first although the turbine is a newly-designed machine by the Elliott Company, rated at 13 MW [Barton, 1970; Bruce, 1970]. The turbine inlet pressure is about 550 kPa (80 lbf/in²), somewhat lower than that for the first unit. Table 4 gives the technical specifications of the unit.

2.5. Units 3 and 4

These two units are essentially identical, each of which has about twice the capacity of either Unit 1 or 2 [Barton, 1970; Bruce, 1970]. The steam flow to the turbine of Unit 4 is about 1.2% greater than that for Unit 3 because the generator of Unit 4 is air-cooled rather than hydrogen-cooled. The photograph in Fig. 8 [PG&E News Bureau (C)] shows the site of these units including a portion of the steam gathering system. The rugged nature of the terrain is also evident from the photograph. Figure 9 is a flow diagram for Unit 3 and Table 5 lists the technical data for the major components.

2.6. Units 5 - 10

These six units, each at 55 MW, are about double the capacity of Units 3 and 4. The increase in unit size was made possible because of the acquired confidence in the ability of the geothermal reservoir to produce the required steam flow over the anticipated plant lifetime [Finney, 1972; Matthew, 1975]. Such confidence was established through nine to ten years of operating experience at the site.

For these units a change was made from barometric jet condensers which were used on Units 1-4 to low-level, tray-type jet condensers. The turbines, all of which are still of the single-cylinder type but of the double-flow variety, were supplied by the Tokyo Shibaura Electric Company, Ltd. (Toshiba). On the ground floor of the power house are the condensers and various auxiliaries; the turbine and operating floor are on an elevated deck. As can be seen in the heat balance diagram of Fig. 10 [Matthew, 1975], no cooling water pump is needed between the cooling tower water basin and the low-level jet condenser owing to the condenser vacuum. Auxiliary cooling water pumps are needed, however, to handle the requirements of the inter- and after-condensers, the cooler for the hydrogen used to cool the generator and the turbine.

lubricating oil coolers. About 4% of the gross electrical output is required for the plant auxiliaries such as circulating water pumps, cooling tower fans, etc.

The photographs in Figs. 11 and 12 show the site of Units 5 and 6 and of Units 7 and 8, respectively [PG&E News Bureau (D), (E)]. Table 6 contains the technical data on the major components.

2.7. Units 11 and 12

Although these two units do not share a common power house (see Fig. 4), they are essentially twin units and represent another step upward in unit capacity. Each is rated at 110 MW and uses a tandem-compound, four-flow turbine manufactured by Toshiba. Technical data for these units are given in Table 7. These units represent about the maximum feasible capacity (per unit) in The Geysers; with the exception of Unit 13, it is planned that all future units will be 110 MW in capacity.

2.8. Unit 13

The No. 13 Unit which is expected on-line in the fall of 1979 is unique in several respects. It is the first unit to be built in Lake County rather than Sonoma County. It is the first unit to be supplied with steam from a producer other than Union-Magma-Thermal; in this case, the supplier is Aminoil (formerly Signal Oil and Gas Company). It will be the largest single geothermal unit in the world with a rated capacity of 135 MW. The unit will be fitted with a turbine manufactured by the General Electric Company, this being the first turbine from an American manufacturer to be installed at The Geysers in over a decade. The turbine is of the tandem-compound arrangement with five impulse-reaction stages in each of the four flows.

This unit will be located in the lower southwest section of Lake County, just over the boundary from Sonoma County (see Fig. 4). This places the unit on the eastern side of the Mayacmas Mountains in a sheltered valley which is known as Hidden Valley. It lies about 4 km (2.5 mi) southeast of Units 9 and 10, the closest of the other units at The Geysers, and will feed power to the Fulton Substation of the PG&E by means of a new 230 kV transmission line which will run 3.4 km (2.1 mi) to join the one from Units 9 and 10 [GEM, 1977 (B)].

The unit was initially designed with a direct-contact condenser of the low-level jet type; however, it will be built with a surface condenser of the shell-and-tube type in order to assist the hydrogen sulfide abatement system which will also be installed on the unit. This will be the first unit to have a surface condenser at The Geysers, and the first unit of any dry steam geothermal plant in the world to be so equipped. Furthermore, this unit, and all succeeding units, will be fitted with a means of controlling the hydrogen sulfide emissions from the plant. A Stretford system (see Sect. 2.13) will be employed on those units which are expected on-line in the near future.

Owing to these late design changes, the technical specifications for the unit are not known as reliably as would otherwise be the case. Table 8 lists these particulars as they are known at this time. Figure 13 shows a simplified schematic/heat balance diagram [PG&E, 1975].

2.9. Unit 14

This unit is similar in design to Units 11 and 12, having a capacity of 110 MW, with Toshiba turbines and steam furnished from Union-Magma-Thermal. The plant will be situated near Big Sulphur Creek, about 2 km (1.2 mi) southeast of Units 1 and 2 (see Fig. 4).

However, unlike Units 11 and 12, Unit 14 will be equipped with a Stretford hydrogen sulfide removal plant, and a shell-and-tube surface

condenser. It is interesting to compare the plant specifications for the two cases: (i) no H_2S abatement (Fig. 14) and (ii) with Stretford abatement system (Fig. 15). For the latter case, it may be possible to produce about 3% more output from the same input by lowering the turbine exhaust pressure from 13.5 kPa (4 in Hg) to 10.2 kPa (3 in Hg). In addition, the steam flow to the turbine will increase by about 1% owing to the reduced steam requirements of the gas ejection system when the Stretford plant is used. However, the flow of cooling water through the cooling tower is increased significantly (59%) because of the shell-and-tube heat exchanger instead of the direct-contact condenser.

Table 9 contains the technical particulars for Unit 14 with the Stretford plant and the shell-and-tube surface condenser.

2.10. Unit 15

This unit will be rated at 55 MW, will have a double-flow, impulse-reaction turbine manufactured by the General Electric Company, will be supplied with steam from Thermogenics, and will be fitted with H_2S abatement equipment. It will be located in the western portion of the geothermal field (see Fig. 4).

Figure 16 shows a heat balance diagram for the earlier design of the unit, before the inclusion of the Stretford plant. A heat balance diagram for the modified plant is not available at this time. Table 10 lists the technical specifications for the modified unit; many of the values shown have been estimated and are subject to refinement as the plant design moves into its final stage.

2.11. Future units

2.11.1 PG&E units

It is expected that Units 16 and 17, both to be rated at 110 MW, will be commissioned in 1981. The former will be located in Lake County, the latter in Sonoma County. The former will be supplied with steam from Aminoil, the latter from Union-Magma-Thermal. Toshiba will manufacture the turbines for both of these units. Table 11 contains the specifications for the units, as well as is known at this time.

Units 18-21 should come on-line two at a time, each with an installed capacity of 110 MW. Units 18, 20 and 21 will use steam from Union-Magma-Thermal; Unit 19 will be supplied by Aminoil. It is expected that Unit 18 will be in Sonoma County and Units 19-21 will be in Lake County [Cossetta, 1977].

2.11.2. Other units

The Northern California Power Agency (NCPA) plans to construct a 110 MW plant to serve the communities of Lodi, Roseville, Santa Clara, Alameda, Ukiah, Healdsburg and Lompoc along with the Plumas-Sierra Rural Electric Cooperative [GEM, 1977 (A)].

The plant will be furnished with steam from wells of the Shell Oil Company, and be built on one of Shell's leases in The Geysers steam field. It is expected to come on-line in 1981. The unit will require about 907 Mg/h (2×10^6 lbm/h) of steam, similar to the 110 MW units of the PG&E at The Geysers.

. 2.12. Materials of construction

A primary factor in determining the materials used in the manufacture of the various components of a geothermal power plant is the composition of the geothermal fluid. Table 12 lists the concentration of the constituents of

the steam found at The Geysers [Reed and Campbell, 1975]. The data were taken from measurements made on 61 wells during the period 1972 through 1974 by PG&E. It may be seen that carbon dioxide, hydrogen sulfide, methane and ammonia are the main constituents carried by the steam, amounting to about 95% of the total impurities.

The steam from The Geysers field is relatively noncorrosive as it comes from the wells in a slightly superheated state. Thus, carbon steel (ASTM A106 Br.B or equivalent) may be used in the gathering system, including main steam pipelines, valves and strainers. The turbines are made from manufacturer's standard materials for the most part, with items of cast, forged or fabricated steel. The casing is carbon steel. The blading, however, is of 13% chrome steel. Moisture removal provisions exist in the lower pressure stages where the expansion leads to higher moisture content. Such moisture traps are of standard design and are used in conventional steam turbines as well [Finney, 1972]. The quality of the steam at the turbine exhaust hood is typically about 90%.

The corrosive nature of the geofluid becomes manifest when the steam condenses, especially in the presence of air. As with all turbines which operate under vacuum conditions, some infiltration of air into the turbine through the seals is unavoidable. Under condensation, the noncondensable gases become more concentrated, the hydrogen sulfide in the presence of air oxidizes to weak sulfuric acid, and the fluid becomes highly corrosive to such materials as carbon steel, cast iron, copper-based alloys, zinc, cadmium, silver, wood and concrete.

The condenser is comprised of a shell of carbon steel plate overlaid with 1.6 mm (1/16 in) thick Type 304 (19% Ch, 9% Ni) stainless steel and internals made of solid stainless steel. The condensate lines are fabricated from Type 304 stainless steel pipe. The condensate pumps are of conventional

canned, vertical design, but with all wetted parts, including impellers and bowls or volutes, made of austenitic Type 304 stainless steel. The circulating water lines above ground are made of aluminum pipe of Type 3003, 3053 or 6061. Aluminum alloys with no copper content are used.

Reinforced concrete pipe was used for underground water pipes in earlier units, but this has not been totally satisfactory. Newer units use glass-reinforced plastic for all buried piping between the power house and the cooling tower. In addition, good results have been obtained with cement-asbestos, epoxy-lined pipe.

The cooling towers are of the mechanical, induced-draft type of conventional design, but containing Type 304 stainless steel or aluminum for wetted metal parts. Redwood is used for structural support members of the water distribution headers and basins; transite forms the tower siding. Where cast iron must be used, it is covered with a thick coating of coal-tar epoxy resin or other plastic material. Wood is unsuitable as tower fill material; polystyrene, polypropylene or polyvinyl chloride (PVC) are acceptable alternatives. The preferred material is PVC because of its strength and fire-retardant properties.

Stainless steel, aluminum or plastic-lined material is used for all pipes carrying condensate or cooling water. Concrete surfaces exposed to these waters are coated with coal-tar epoxy compounds or synthetic rubber coatings. Heat exchangers are made from aluminum or austenitic stainless steel.

Since copper alloys and silver are susceptible to corrosive attack by hydrogen sulfide, electrical equipment should not be made of these materials. Experience shows that tin alloy coatings are effective in resisting corrosion, but they are unsatisfactory on current-carrying contact surfaces. Aluminum, stainless steel and some precious metals are particularly effective. Platinum inserts or plating have been used on these contacts.

The outdoor equipment must be protected since the air contains corrosive elements. The fog and mist produced by the evaporation from the cooling towers is quite corrosive. Epoxy paints and heavy galvanizing resist the attacks of the corrosive gases.

2.13. Effluent and emissions handling systems

All units currently operating at The Geysers employ evaporative water cooling towers in conjunction with direct-contact jet condensers. Since the amount of condensate produced from the geothermal steam exceeds the amount of water which is evaporated in the towers, a problem presents itself for the proper disposal of the excess liquid. In addition, the emission of the gaseous impurities in the geothermal steam into the atmosphere must be considered because of the potential hazard to health, wildlife and vegetation.

2.13.1. Liquid effluent

Approximately 20% of the mass of geothermal steam produced from the wells must be disposed of as excess liquid from the cooling tower basin. From 1960 to 1970 the problem was solved simply by allowing the liquid to run into the nearby Big Sulfur Creek. Beginning with Units 5 and 6, however, the excess water has been reinjected into the producing reservoir. For each 55 MW unit, $1700 \text{ m}^3/\text{d}$ (1.4 acre-ft/d) must be reinjected. In 1974, four wells were employed for the reinjection of approximately $14000 \text{ m}^3/\text{d}$ (11.4 acre-ft/d) of excess water [Reed and Campbell, 1975]. Since the steam producing reservoir is of anomalously low pressure relative to hydrostatic conditions (see Sect. 2.1.), it is not necessary to pump the liquid down the well; pumping is required only to move the liquid from the cooling tower sites to the reinjection wells.

2.13.2. Gaseous emissions

As mentioned earlier (see Sect. 2.12 and Table 12), the geothermal steam carries with it a number of constituents. The noncondensable gases are vented

to the atmosphere at two places in the plant, the gas ejector and the cooling tower, as may be seen, for example, in Fig. 14.

The composition of the gas stream leaving the gas ejector is shown in Table 13, for nine of the early units at The Geysers. Measurements were taken by PG&E over the period from 1967 to 1974; the values shown are averages.

The output from the stacks of the cooling tower have been estimated by PG&E and Table 14 lists the results for plants without emissions controls.

The most objectionable of the gases discharged is hydrogen sulfide, H_2S , owing in part to its unpleasant smell and to the very low level of detection by the human olfactory sense. The California ambient air quality standard for H_2S is 30 parts per billion (ppb), based on an assumed odor detection threshold [Semrau, 1976]. Although no Federal standards exist for H_2S , the U.S. Environment Protection Agency (EPA) has suggested a maximum of 200 g/MW·h of electrical production or its equivalent [Hartley, 1977].

The first ten units at The Geysers were provided with no means of control of H_2S emissions. The daily operation of these 10 uncontrolled units produce 22 Mg/d or 2300 g/MW·h of H_2S [Weres, 1976]. All new units will be fitted with some type of H_2S abatement system. An iron hydroxide system of about 70% efficiency was tested on Unit 11. It discharges on the average 2 Mg/d or 800 g/MW·h into the atmosphere, including pre-plant emissions and vent emissions which occur during plant shutdown and are uncontrolled at this time [Weres, 1976].

Units 13, 14, 15 and future units will have surface condensers instead of jet condensers. Separate chemical processing plants operating on the Stretford process will remove the hydrogen sulfide on Units 13-15 [Semrau, 1976]. A simplified flow diagram of the Stretford process is shown in Fig. 17 [Laszlo, 1976]. Since this forms an independent facility, it will have no direct influence on the power plant performance. The product of the Stretford process is pure, marketable sulfur.

The bulk of the H_2S (90%) will be confined to the noncondensable gas stream where it can be effectively controlled. The concentration at the exit of the gas extractor is guaranteed by the vendor not to exceed 10 parts per million which is equivalent to an efficiency greater than 99.9% [Semrau, 1976]. However, the overall plant abatement of H_2S with such a system is expected only to be between 78 and 92% since about 10% of the H_2S will still reach the cooling tower through the condensate from the surface condenser. As can be seen from Fig. 15, about $0.25 \text{ m}^3/\text{s}$ (4000 gal/min) of condensate, containing about 10% of the H_2S which was originally present in the steam, is fed into the cooling water and eventually reaches the tower.

Another potentially harmful emission from The Geysers plant is radon. Radon is a radioactive decay product of uranium found in the gaseous state in sedimentary rocks. It is carried by the natural steam from the reservoir to the surface and emitted along with the other noncondensables. It is detectable in extremely minute concentrations owing to its radioactivity. The California Department of Health requires radon concentrations be less than 3 pCi/l in uncontrolled areas. (Note: 1 pCi of radon $\approx 6.8 \times 10^{-21}$ kg.) Table 15 gives data on the emission of radon from The Geysers plants. As can be seen from the table, the natural steam from the wells contains about 2.8 times the allowable amount and the ejector gas carries nearly 2 million times the allowable limit [Reed and Campbell, 1975]. Nevertheless, measurements show that the standards are not exceeded in those areas of normal access by humans.

The problem of emissions to the atmosphere is not totally solved by abatement equipment that operates at the power house. There are as yet no emission control devices installed in the pre-plant elements. Thus, during plant shutdown, steam is vented directly to the atmosphere and constitutes a total failure, in effect, of the abatement systems. Venting is employed to avoid damage either

to the producing reservoir or to the steam wells which might occur under totally closed-in conditions. A possible technique to control vent emissions of H_2S is to use a bed of iron oxide to absorb the gas. This would eliminate the problems which would arise from other systems that require the condensation of the steam.

The projected emission levels of H_2S are shown on Fig. 18 [Ramachandran, 1977]. It may be seen that, with an overall abatement of 90%, the H_2S emissions in the year 2000 will be comparable to those at present, even though the capacity will have grown by a factor of ten to 5100 MW.

2.14. Economic factors

The cost to an electric power company of producing a unit of electricity and of transmitting it to the customer is the most important factor which influences the choice of energy conversion system in a free marketplace.

Three basic expenses contribute to the total cost of electricity; (1) capital investment which includes the outlay for the power plant, interest incurred during construction, working capital, organization, start-up expenses, and costs associated with transmission line construction, if necessary; (2) operating and maintenance expenses; and (3) fuel cost which, in the case of geothermal power plants, means the price the utility must pay to the field developer for the geofluid, be it steam or hot brine. At The Geysers, the utility purchases dry steam "over the fence" from the supplier, according to a pricing formula which includes a surcharge levied on the utility by the supplier to cover the cost of disposing (by reinjection) of excess condensate.

The formula which PG&E uses to buy steam for its Geysers units is as follows [Dutcher and Moir, 1976]:

$$C_S = [2.11 E_F (\bar{C}_F / \bar{C}_F^0) (MHR / MHR^0) + E_N \bar{C}_N] / (E_F + E_N) ,$$

where

- C_S = cost of steam (mill/kW·h) for year n,
 E_F = electricity produced from fossil fuel during year n-1,
 E_N = electricity produced from nuclear fuel during year n-1,
 $\bar{C}_F$ = average cost of fossil fuel for year n-1,
 $\bar{C}_N$ = average cost of nuclear fuel for year n-1,
 $\bar{C}_F^0$ = average cost of fossil fuel in 1968,
MHR = minimum heat rate for fossil plants during year n-1,
MHR⁰ = minimum heat rate for fossil plants during 1968,
2.11 = negotiable constant.

Thus, the cost of geothermal steam for any year is determined by the amount and cost of electrical production by fossil and nuclear means during the previous year. Base figures are taken for the cost of fossil fuel and fossil plant heat rate during 1968. In addition, there is a surcharge of 0.5 mill/kW·h for reinjection of the spent geofluid. The historical price of The Geysers steam since 1969 is given below:

<u>Year</u>	<u>Price</u> (mill/kW·h)
1969	2.65
1970	2.64
1971	2.74
1972	2.90
1973	3.15
1974	3.73
1975	7.39
1976	11.35
1977	14.10
1978	16.05

These prices include the surcharge for liquid effluent disposal [Ramachandran, 1977; Cossette, 1978].

The only other geothermal steam contract at The Geysers is the one signed on June 27, 1977 between Shell Oil Company and the Northern California Power Agency (NCPA). (See Sect. 2.11.2.) The contract calls for NCPA to pay Shell according to the amount of steam delivered. The initial price, at the time of the contract, was \$0.6917/1000 lbm of steam. Beginning on July 1, 1977, the price will be adjusted semi-annually by the GNP Implicit Price Deflator (IPD) Index published by the U.S. Department of Commerce for the preceding calendar quarter [Lindsay, 1977]. The IPD is the ratio of the GNP (in current dollars) to the GNP (in constant 1972 dollars) for the current period. The geothermal steam supplied by Shell must be dry and at a pressure no lower than 799.8 kPa (116.0 lbf/in²); when the amount of noncondensable gases exceeds 0.5% (weight), the flow rate of steam will be corrected accordingly. Uncontaminated waste liquid will be returned to Shell for disposal at a temperature not greater than 79.4°C (175°F) and at a pressure not less than 262 kPa (38 lbf/in²).

The history of capital investment by PG&E at The Geysers is given in Table 16 where all figures are in current dollars [Dan, et al, 1975; Cossette, 1978]. A comparison between the cost of electricity generated by Units 11 and 14 is shown in Table 17 [Ramachandran, 1977], in which cost figures are given in constant 1976 dollars. The effect of inflation is nullified in this comparison, leaving the added expense of the equipment additions and modifications needed to meet the H₂S emissions constraints as the main contributing factor causing the 1.6 mill/kW·h or 9% increase in the cost of electricity. Of course since Unit 14 is under construction, the cost of electricity from that unit, 19.2 mill/kW·h, is estimated.

If it becomes mandatory to guarantee 99% abatement of H₂S, it will be necessary to install a condensate treatment system, in addition to the

noncondensable gas treatment plant. The cost of providing this extra clean-up operation is estimated to be about 0.7 - 1.8 mill/kW·h. Details are shown in Table 18 for two types of treatment, peroxide and ozone [Ramachandran, 1977].

For the operating year 1976, PG&E reported [Mahoney and Bangert, 1977] that their geothermal power plants produced electricity at the lowest cost of any other type steam plant in its system. The figures (in 1977 dollars) are as follows:

geothermal.	18 mill/kW·h
nuclear	24 mill/kW·h
coal-fired.	26 mill/kW·h
oil-fired	36 mill/kW·h.

In addition, geothermal plants were the least expensive to construct, being 26% cheaper than oil-fired plants, about half as expensive as coal-fired plants, and costing only 38% of a typical nuclear plant. All comparisons are on a dollars-per-kilowatt basis.

2.15. Plant operating characteristics

The operation of The Geysers power plants is challenging because of several factors, including the isolated location, rugged mountain terrain, and environmental and operating requirements unique to geothermal plants [Matthew, 1975].

All units are designed for automatic operation. A computer-based information and control center is located at Units 5 and 6. It is manned full-time. Information and alarms from each unit in the system are sent to this center for action by the operator.

The units function as base-load units since abrupt changes in well flow rates cause damage to both the wells and the turbines owing to gross carry-over of water, dust, and debris. When a unit trips off the line, the wells connected to it are allowed to vent to the atmosphere through silencers. These

wells are not closed in unless it is determined that the unit must remain off-line for an extended period for maintenance or repairs.

The ambient temperature fluctuates during the year from about -7 to 46°C (20 to 115°F) necessitating forced ventilation of the electrical equipment during the summer and special precautions to prevent freezing of outside equipment, particularly the cooling towers, in the winter. Automobile access to the plant during the winter is difficult owing to narrow, mountain roads that are often ice-covered.

Table 19 contains information on plant reliability [Matthew, 1975]. Capacity and availability factors are shown for The Geysers system over the operating history of the plant up to 1975. For comparison, figures are quoted for fossil-fired plants in the PG&E system. The Geysers has the highest capacity factor which is an indication of preferential base-load usage. The availability factor is comparable to but slightly lower than that for the fossil plants.

The higher forced outage rate for the geothermal plants is a result of the unexpected failure of auxiliaries and components that usually function without trouble in conventional plants. These components include turbine blades and shrouds, rotating electrical apparatus (exciters and motors), small pumps, and cooling tower fan blades. A spare parts maintenance program is designed to minimize down-time.

Geothermal units at The Geysers are dismantled, cleaned and repaired every 2-3 years compared with 5-8 years for conventional units. Down-time is less, i.e., 3-4 weeks compared to 8-12 weeks, because of the smaller size and relative simplicity of the geothermal units. As experience is gained, the schedule outage rate should continue to improve.

2.16. Resource utilization efficiency

The resource utilization efficiency, η_u , is the proper measure of the energy conversion process which takes place in a geothermal power plant [Milora and Tester, 1976]. The factor is based on the available work in the geothermal fluid, either as it exists in the formation (or at the well-bottom), or as it is supplied to the boundary of the plant (or at the wellhead). It is calculated from

$$\eta_u = w/w^o \quad , \quad (1)$$

where w is the specific net work output of the plant, in kJ/kg (Btu/lbm), and w^o is the specific available work of the geofluid in the same units; w^o may be found from

$$w^o = h_1 - h_o - T_o (s_1 - s_o) \quad , \quad (2)$$

where subscript 1 is used for the initial state of the geofluid and subscript o represents the ambient sink condition (i.e., saturated liquid water at temperature T_o). In the case where the initial state is chosen at the wellbottom, an additional term, $-gL$, must be included in Eq. (2). This term accounts for the potential energy of the fluid at the bottom of the well a distance L below the surface, and is usually a small term except for very deep wells.

For the present case, state 1 will refer to the condition of the steam as it arrives at the power house. The sink temperature will be taken as 27°C (80°F), approximately the temperature of the cooling water available from the cooling towers. The specific net work output, w , is taken per unit mass of steam entering the plant (which includes steam used for gas ejectors, gland sealing, etc.).

Table 20 contains a summary of the calculations on resource utilization efficiency, η_u , for the eleven operating units together with estimates for the four units which are under construction. It may be seen that η_u ranges from 50-56%. Units 13 and 15 are expected to operate with steam at the lowest temperature of any unit (170°C (338°F)) and may have the lowest efficiency of all the units at The Geysers. Although they are not included in the table, Units 16 and 17 will be similar to Unit 14 in design and performance; i.e., they may be expected to operate at a 56% resource utilization efficiency.

3. Magmamax dual binary plant - East Mesa, CA

There are presently two methods which may be used to convert the energy in a liquid-dominated hydrothermal resource into electricity in a practical manner. The first involves either separating the vapor fraction for use in a steam turbine or combining a separation with a subsequent flashing process of the residual liquid to generate more vapor. The second involves the use of the hot geofluid as a heating medium for a secondary working fluid of a suitably low boiling point which is then used in a more or less conventional, basic Rankine cycle. The geothermal power plant being constructed at East Mesa, California, by the Magma companies is of the latter type, and is called the Magmamax⁽¹⁾ dual binary cycle. When completed late in 1978, it will be the first geothermal power plant of this type in commercial operation in the United States. The plant will have a rated capacity of 11.2 MWe.

3.1. Geology

The plant is being built on the East Mesa KGRA in the Imperial Valley, about 2.4 km (1.5 mi) east of the junction of routes I-8 and 115 or about 8 km (5 mi) southeast of Holtville. The plant site is in Section 7, Township 16 South and Range 17 East, (T16S-R17E), of the KGRA. The area is a well-known thermal anomaly; the plant is located between heat flow contours of 6.0 and 7.0 Heat Flow Units (HFU).⁽²⁾ Figure 19 shows a heat flow contour map of the area [BurRec, 1977]. The plant is adjacent to the U.S. Bureau of Reclamation's East Mesa Test Site. Magma Power Company holds 756 ha (1868 acres) of federal leases for which they paid \$2.25/acre [Williams, et al, 1977].

⁽¹⁾ Magmamax Process, U.S. Pat. No. 3757516, Magma Energy, Inc., Los Angeles.

⁽²⁾ 1 HFU = 1 $\mu\text{cal}/\text{cm}^2 \cdot \text{s}$.

The East Mesa KGRA is part of the larger Mexicali-Imperial Rift Valley, an extension of the system of mid-oceanic ridges and rifts which circle the earth. The valley is oriented northwest-southeast, and is bounded by the San Andreas fault zone on the northeast and by the San Jacinto fault zone on the southwest. The most prominent feature of the valley is the Salton Sea, 48×16 km (30×10 mi) in size and lying at about 72 m (235 ft) below sea level. During the last 2000 years and up until about 300 years ago, the area now occupied by the Salton Sea was the site of the larger Lake Cahuilla. The irrigated agricultural land that exists today in the Imperial Valley is confined roughly within the ancient shoreline of Lake Cahuilla; the East Mesa KGRA lies at the eastern boundary of this ancient shoreline [Saint, 1976]. The Salton Sea was formed when the Colorado River flooded the area during 1905-1906; its level is maintained by the runoff from irrigation in the valley.

The structure of the valley is characterized by predominantly transform faults with lateral movement, crustal spreading, high heat flow, faulting and volcanic activity. The crystalline basement of the valley in the East Mesa area is at a depth of about 3.7 km (12,100 ft). The basement is overlain with water-saturated sediments of the late Cenozoic era (Quaternary and late Tertiary periods), having been deposited by the Colorado River and other streams that have flowed through the Colorado River drainage basin during the last 4 million years. The depth to the top of the hydrothermal (convective) reservoir is estimated to be 1 km (3281 ft) [Williams, et al, 1977]. Although there are no surface thermal manifestations in the East Mesa area, the subsurface hydrothermal reservoir is quite extensive, containing perhaps 56 km^3 (45×10^6 acre·ft) of water-bearing sediment at a temperature of 180°C (356°F). The reservoir is sealed and insulated from the surface by a layer of impermeable silts and clays [Combs and Muffler, 1973; Saint, 1976]. The reservoir

cap is of variable thickness, having a maximum thickness of about 700 m (2300 ft).

Geophysical surveys of the East Mesa KGRA have been conducted by a number of people [Biehler, 1971; Biehler and Combs, 1972; Biehler, et al, 1964; Combs, 1971; Combs, 1972; Douze, 1971]. Some results of these studies are shown in Figs. 20-22. Figure 20 gives contours of constant temperature gradient which were obtained by means of 37 boreholes ranging in depth from 30 - 450 m (98 - 1476 ft) [Combs, 1971]. Gradients as high as 20°C/100 m (11°F/100 ft), or about 6 times the normal average temperature gradient, are present near the center of the KGRA. Figure 21 shows a residual Bouguer gravity map which reveals an area of about 250 ha (618 acres) in which there is at least a 4 mGal or 0.04 mm/s^2 closure [Biehler, 1971]. It has been suggested that this gravity high is an indication of either an increase in density of the sediments caused by cementation and thermal alteration by circulating hot brines or the emplacement of higher density igneous rocks [Biehler and Combs, 1972].

Seismic ground noise may be an indicator of a geothermal reservoir when reinforcing evidence exists from other geophysical measurements. Figure 22 shows a ground-noise map of the East Mesa KGRA, where contours are given in decibels relative to 1 (nm/s)^2 per Hertz in the passband 3-5 Hz [Douze, 1971].

Since the East Mesa region constitutes a "hidden reservoir" owing to the lack of surface manifestations, its discovery marked a major triumph for the science of geothermal exploration, even though the original indication of a possible thermal anomaly came about accidentally through oil and gas drilling in the area [Koenig, 1977].

3.2. Wells and gathering system

The Magmamax dual binary plant will be supplied with pressurized geofluid from three wells. Down-hole pumps will be used to prevent flashing and help inhibit the deposition of scale. Each well is expected to produce about 218 Mg/h (481,000) lbm/h) of brine at wellhead conditions of 182°C (360°F) and 1.35 MPa (196 lbf/in²). A booster pump at the power plant will raise the pressure to 1.86 MPa (270 lbf/in²). The geothermal fluid will circulate through a number of heat exchangers before being reinjected into the reservoir through two reinjection wells. The spent fluid will enter the reinjection pump at 82°C (180°F) and 0.81 MPa (117 lbf/in²); the pump will raise the pressure to 1.3 MPa.

3.3. Energy conversion system

The flow diagram for the plant is shown in Fig. 23 [Anderson, 1976 (A); Hinrichs, 1978 (A)]. The planned layout design, as of December 20, 1976, is shown in Fig. 24 [Anderson, 1976 (B); Hinrichs, 1978 (A)]. Preliminary design specifications of the plant are given in Table 21. It may be noticed that there are two parallel power loops, one using isobutane, $i\text{-C}_4\text{H}_{10}$, and one using propane, C_3H_8 , as the working fluid. The two loops are connected by means of the recuperator which makes use of the superheated isobutane leaving the turbine to preheat and vaporize the propane. On the basis of the preliminary specifications quoted for the plant, the system will be capable of a resource utilization efficiency of about 52%, assuming a sink temperature of 27°C (80°F). The specific brine consumption will be about 58.5 kg/kW·h (129 lbm/kW·h). The objective of the developers of the plant is to reduce the consumption to less than 45.4 kg/kW·h (100 lbm/kW·h) [Hinrichs and Falk, 1978].

The isobutane turbine was built by the York Division of Borg-Warner Corporation to the specifications of J. Hilbert Anderson [Anderson, 1973].

The machine is of the double-flow type with each side being a 3-stage radial-inflow turbine. The unit is essentially a compressor which has been re-designed for turbine duty. The turbine is expected to operate at an isentropic efficiency of about 77%.

The propane turbine was built by Mafi-Trench and is typical of machines of the type used for low-temperature applications. It is of the radial-inflow type; the preliminary design specifications indicate an expected isentropic efficiency of about 86%, [Mafi, 1978].

About 10.5 ha (26 acres) will be dedicated to the storage ponds required for the phased cooling system. The two ponds will hold roughly $1.7 \times 10^5 \text{ m}^3$ (138 acre·ft) and $9.0 \times 10^4 \text{ m}^3$ (73 acre·ft) of water, respectively, for a storage time of about 16 hours [Hinrichs, 1978(B)]. The combined use of phased storage and spray cooling is expected to produce cooling water at a temperature only 2.2°C (4°F) above the design wet-bulb temperature of 14.4°C (58°F).

4. Binary demonstration plant - Heber, CA

San Diego Gas and Electric Company (SDG&E) will serve as project manager for the construction and operation of a proposed 65 MW (gross), 45 MW (net electrical) binary demonstration plant at the Heber KGRA in the Imperial Valley.

The plant is intended to demonstrate the practical use of liquid-dominated hydrothermal resources of the type found at Heber. Since the vast majority of the geothermal reserves in the United States are of the liquid-dominated type, successful implementation of the binary plant should result in an acceleration of the development of geothermal plants in this country.

SDG&E has put together a consortium of organizations which are jointly sponsoring the project [SDG&E, 1977 (B)]. These are:

San Diego Gas & Electric, Owner (77%) and Project Director;

Imperial Irrigation District, Owner (10%), Cooling Water Supplier and Potential Purchaser of Power;

Los Angeles Dept. of Water and Power, Owner (10%);

Southern California Edison, Owner (3%);

Electric Power Research Institute, Major Contributor (\$4.56 million);

California Energy Resources Conservation and Development Commission, Contributor (\$250,000);

Nevada Power Company, Contributor (\$50,000);

Portland General Electric, Contributor (\$50,000).

It is anticipated that construction will begin in early 1979, and operation will start in 1981.

4.1. Geology

The Heber KGRA is located in the Imperial Valley of southern California, about 32 km (20 mi) west-southwest of the East Mesa KGRA. The general

characterization of the geology of the area given in Sect. 3.1 applies in this case as well. The important differences between the two areas are as follows. The subsurface geofluid temperature is 190°C (374°F) at Heber compared to 180°C (356°F) at East Mesa. The amount of total dissolved solids in the Heber geofluid is as much as one order of magnitude greater than at East Mesa, i.e., 14,000 - 25,000 ppm (Heber) to 2,500 ppm (East Mesa). The depth to the crystalline basement in the Heber area is greater than at any other known site in the Imperial Valley, being an estimated 7 km (4.3 mi) [Geonomics, 1976]. Finally, the land in the Heber area is irrigated and of agricultural value, whereas for the most part, the East Mesa KGRA consists of desert shrubland, lying to the east of the East Highline Canal [Williams, et al, 1977]. The convecting reservoir in each case consists of deltaic sediments which are considered relatively soft for purposes of drilling.

4.2. Wells and gathering system

It is proposed to drill all the production wells for the plant from a single platform using the technique of directional drilling. About 12 - 14 wells will be needed to supply the required flow rate of brine, assuming that each well can produce about 295 Mg/h (650,000 lbm/h) [Holt/Procon, 1976]. The wells will be fitted with down-hole pumps to prevent flashing of the geofluid and to assure the required flow rate. The spent brine will be returned to reservoir by reinjection through 7 wells drilled at three islands located equally spaced on the circumference of one quadrant of a circle described on a 3 km (1.9 mi) radius from the plant. Between 5 - 9 MW of electrical power will be consumed by all pumping operations [SDG&E, 1977(A)]; Holt/Procon, 1976].

The field is being developed by Chevron Resources Company (a subsidiary of Standard Oil Company), Union Oil Company of California, and New Albion

Resource Company (a subsidiary of SDG&E). Negotiations are in progress to establish a contract for the supply and sale of the geothermal fluid.

4.3. Energy conversion system

Several energy conversion systems were studied for the Heber KGRA by The Ben Holt Company and Procon Incorporated [Holt/Procon, 1976]. The report showed that a binary plant would be able to produce power at a lower cost than either a double-flash or a hybrid flash-binary plant. The calculations required a number of assumptions about which it is not possible to achieve a consensus of agreement [Elliott, 1977]. It can be demonstrated, for example, that by accounting for the power required for pumping the wells in the binary cycle and by eliminating it for the flashed-steam cycle, the conclusion on the cost of electricity relative to these two systems is reversed.

The binary energy conversion cycle, nevertheless, has been chosen for other reasons besides its apparent economic advantage over competing systems. The binary cycle is believed to be more broadly suited to the moderate temperature reservoirs found in the United States. Furthermore, the successful demonstration of the binary cycle will add one more option to the available energy conversion systems for geothermal applications.

The process flow diagram for the proposed plant is shown in Fig. 25; the technical specifications are listed in Table 22. Although the exact determination of the working fluid has not been made yet, it is expected to be a mixture of isobutane and isopentane. The composition of the mixture will be changed over the course of the lifetime of the plant to maintain as near an optimum operating condition as possible should the reservoir temperature decline as is anticipated. The resource utilization efficiency is about 41% based on the present design specifications and allowing for 15,000 ppm

of total dissolved solids in the brine. The plant would require a specific brine flow of about 68 kg/kW·h (149 lbm/kW·h).

4.4. Environmental effects

There are anticipated to be only two areas of environmental concern:

(1) a guaranteed supply of cooling water, and (2) possible induced seismic effects or land subsidence.

Wet cooling towers will evaporate large amounts of water that must be made up from a reliable source of clean water. Approximately 725 Mg/h (1.6×10^6 lbm/h) will be required. Irrigation water will be supplied to serve this purpose for the first five years of operation through the Imperial Irrigation District (IID). Beyond that point in time, the source of water for make-up purposes is not certain.

Reinjection of the withdrawn geothermal fluid should minimize problems related to subsidence and seismicity. However, an extensive array of monitors have been installed in the Imperial Valley to keep close track of both of these potential hazards.

Little degradation of the air quality in the area is expected since there are no emissions of noncondensable gases in the case of the binary plant as there would be for a geothermal steam plant.

4.5. Economic factors

The demonstration plant is expected to cost about \$42 million [SDG&E, 1977 (A)]. This amount covers only the capital costs associated with the construction of the power plant, and does not include the cost of transmission lines, geothermal wells, brine gathering and distribution systems. Additional costs will be incurred for testing, operations and maintenance.

It should be noted that the Holt/Procon study presented a somewhat different economic picture [Holt/Procon, 1976]. The power plant cost was estimated to be \$28.5 million, exclusive of any expenses for design and construction. A detailed assessment of the costs associated with the generation of electricity resulted in a value of 35.223 mill/kW·h for the cost of electricity. The analysis required a number of assumptions including ones relating to taxes and plant capacity factor (85%). Costs were based on a plant requirement of 3.15 Gg/h (6.94×10^6 lbm/h) of brine at a cost of \$0.265/Mg ($\$0.12/10^3$ lbm). The cost of electricity, in 1980 dollars, consisted of the following components:

"Fuel"	16.69 mill/kW·h
Fixed charges.	15.03
Operating and maintenance.	3.22
Transmission	<u>0.28</u>
Total cost of electricity.	35.22 mill/kW·h

Recently, SDG&E has issued revised estimates of the cost of electricity from the demonstration plant [Ellis, 1978 (A)]. The capacity factor has been lowered to 75%, plant start-up delayed to 1985, and cost figures are in "levelized" mill/kW·h in 1985 dollars. The contributions from each component are now as follows:

"Fuel"	72.3 mill/kW·h
Fixed charges.	23.3
Operating and maintenance.	16.7
Transmission	<u>7.7</u>
Total cost of electricity.	120.0 mill/kW·h

These strikingly different estimates point up the difficulty in assessing projected costs of electricity from a type of energy conversion system

for which there are no precedents and about which a great deal of uncertainty exists. Many of the rules governing the tax situation for owners of such plants are subject to legislation and, perhaps, judicial interpretation. It is impossible to predict with any certainty how reliable a new power plant will be, i.e., the capacity factor can only be estimated. Furthermore, effects of inflation and escalation can only be taken into account in an approximate way.

Nevertheless, it was the conclusion of the Holt/Procon study that electricity produced from the Heber binary demonstration plant would appear to be economically competitive with alternate sources of new power.

5. Republic Geothermal, Inc. flash-steam plant - East Mesa, CA

Republic Geothermal, Inc. is currently developing a portion of the East Mesa geothermal field with the intention to build a 48-MWe double-flash power plant which should be operating in the early 1980's.

5.1. Geology

Republic's plant will be located about 5 km (3 mi) north of the Magmamax dual binary plant. (See Sect. 3.1 and Fig. 19.) Republic holds leases to 2068 ha (5109 acres) by itself, and to an additional 646 ha (1596 acres) jointly with the City of Burbank. As can be seen from Fig. 19, the Republic holdings lie in a region of the KGRA in which the thermal anomaly ranges from a high of about 6 H.F.U. down to less than 4 H.F.U. Otherwise the geology of the area is practically identical to the portion of the KGRA described in Sect. 3.1.

5.2. Wells and gathering system

An analysis of flow tests on well EM 16-29 was recently reported [Elliott, 1978]. The well extends to a depth of 2433 m (7982 ft) with the following casing program:

0.391 m (15 3/8 in) I.D. from wellhead to 283 m (928 ft)

0.276 m (10 7/8 in) I.D. from 283 m to 1355 m (4446 ft)

0.201 m (7 15/16 in) I.D. from 1355 m to 2433 m (7982 ft).

The reservoir pressure was taken as 22.54 MPa (3269 lbf/in²) and the draw-down coefficient as 21 kPa/(kg/s) or 1.38 lbf/in²/(lbm/s). The true reservoir temperature was about 168°C (334°F); the maximum observed flow rate was limited to about 45 kg/s (357,000 lbm/h) by the size of certain elements of the surface equipment. The wells will be operated not in the self-flowing mode (as in these tests), but in a pumped-mode using down-hole, electric-powered,

submersible pumps. It is expected that each well should deliver about 85 kg/s (675,000 lbm/h) of fluid under pumped conditions.

Republic was the recipient of the first award made by the government under the Geothermal Loan Guaranty Program (GLGP). The guaranty was issued in May 1977 and is for \$9 million to drill at least 15 additional producing wells at the East Mesa site. Each well must be capable of producing at least 2 MW of electrical power [Silverman, 1977; ERDA News, 1977].

5.3. Energy conversion system

A single-flash plant of 10 MWe output is planned to be the first of its type in the United States. This pilot plant should be built by 1979 [Holt, 1977].

The main plant will be a 48 MWe double-flash system which is presently being designed. It is anticipated that the plant will begin operation in 1980 or 1981.

Although there are no details available on the specifications for either plant, typical single- and double-flash flow diagrams and thermodynamic state diagrams are shown in Figs. 26 and 27, respectively.

6. Utah Power & Light Co. double-flash plant - Roosevelt Hot Springs, UT

Negotiations are under way among Utah Power & Light Company, Phillips Petroleum Company and Rogers International, a subsidiary of Rogers Engineering Co., Inc. concerning the financing, design, construction and operation of a 52 MWe geopower plant at Roosevelt Hot Springs in Beaver County near Milford, Utah.

In general, Phillips Petroleum, the developer of the geothermal field, will supply steam to Rogers who will be responsible for financing the design and construction of the plant and for operating it. UP&L will buy the power and have an option to acquire the plant after a period of time sufficient to satisfy the utility of the long-term reliability of the plant and the resource.

6.1. Geology

The Roosevelt Hot Springs area is situated at the junction of the Escalante Valley (a north-south trending graben) and the Mineral Range (a horst block running parallel to the east side of the valley). The Mineral Range is characterized by rugged topography and extends about 48 km (30 mi) in length and from 9.6 to 16 km (6 to 10 mi) in width. The Escalante Valley is filled with sediments to a thickness of roughly 1.5 km (0.9 mi) in the center [Lenzer, et al, 1977 (A); Lenzer, et al, 1977 (B)].

Many faults are present throughout the area, several of which have an important influence on the hydrology. Two principal ones are the Dome Fault, which strikes north-northeast through the center of the thermal anomaly, and the Negro Mag Wash Fault, which trends east-west. On the east side of the KGRA there are at least seven eruptive centers with rhyolitic flows. It is the magma at depth which feeds these flows that is believed to be the source of the Roosevelt thermal anomaly.

The hydrothermal reservoir itself is fracture-dominated. The top of the reservoir lies at a depth of about 900 m (2970 ft) over most of the area. A thermal gradient profile was obtained from 39 test holes; five of these at the center of the anomaly registered gradients in excess of 40°C/100 m (22°F/100 ft) or about twelve times the normal gradient. The test holes ranged in depth from 60 to 610 m (197 to 2000 ft). The region within which the thermal gradient exceeds 10°C/100 m (5.5°F/100 ft) covers an area roughly 8 × 13 km (5 × 8 mi). The predominant rock types are Precambrian granite and pliocene or Pleistocene volcanics. The overlaying rock is judged medium-to-hard for drilling purposes [Williams, et al, 1977].

6.2. Well productivity

Since the reservoir is fracture-dominated and the orientation and arrangement of the fractures is not well known, it follows that all wells drilled must be classified as "wildcats". The fracture zones, however, have a remarkably high effective permeability and have yielded well productivities as high as 113 Mg/h (250,000 lbm/h) of flashed steam at a reservoir temperature of about 265°C (507°F). The highest producing well so far yields in excess of 452 Mg/h (1,000,000 lbm/h) of liquid and steam mixture at 250°C (482°F). Total dissolved solids are less than 8000 ppm, and reservoir fluid pressure is nearly hydrostatic.

6.3. Energy conversion system

No details are available at this time concerning the energy conversion system although the plant is expected to be of the separated steam/flash type. Figure 28 shows a typical system of this kind. The availability of cooling water is a severe problem in the area. Although a flash-steam plant with a wet cooling tower produces an excess of condensate, a relatively

small quantity of fresh water is required nevertheless for blow-down purposes. This need will be minimized in the case of the Roosevelt resource since it is relatively low in total dissolved solids.

6.4. Economic factors

Design and construction of the plant is expected to cost about \$35 million. Assistance for the financing of the project has been sought from the Department of Energy. It is hoped that the plant will begin operations during the summer of 1982, although start-up is more likely to be in 1983.

7. Public Service Co. of New Mexico Baca No. 1 plant - Valles Caldera, NM

It has been proposed to build a 50 MW geothermal steam power plant in the Jemez Mountains of north-central New Mexico. Public Service Co. of New Mexico and Union Oil Company of California have submitted a proposal to the Department of Energy seeking \$50 million to help support the design and construction of the plant. If all goes as expected, it should be on-line in 1982 [GEM, 1978].

7.1. Geology

The plant site is in area known as Baca No. 1 within the Valles Caldera KGRA, about 56 km (35 mi) west of Los Alamos and 120 km (75 mi) north of Albuquerque. There are five hot springs in the caldera with temperatures ranging from 25 to 87°C (77 to 189°F). The hydrothermal reservoir temperature is estimated to be between 240 and 280°C (464 - 536°F) [Williams, et al, 1977]. The overlaying rocks are Pleistocene caldera volcanics and are classified as hard for purposes of drilling. The top of the reservoir is estimated to lie about 1 km (3281 ft) below the surface. The U.S. Geological Survey reported that the Valles Caldera KGRA has the potential to support 1870 MW of electrical power production for 30 years [White and Williams, 1975].

7.2. Potential well productivity

The field developers believe that each production well will be capable of providing 91 Mg/h (200,000 lbm/h) of geothermal fluid with a quality of 35% at a wellhead pressure of 965 kPa (140 lbf/in²). Roughly 15 units will be needed to supply the 50 MW plant.

7.3. Energy conversion system

Although no details are available on the type of energy conversion system for the proposed plant, it will likely be of the separated steam/flash type. (See Fig. 28.) There does not appear to be a problem in obtaining sufficient quantities of water for plant requirements.

8. City of Burbank hybrid fossil-geothermal plant

The City of Burbank, California, and a number of neighboring cities in the Los Angeles metropolitan area are looking seriously into the possibility of constructing a hybrid power plant utilizing both fossil and geothermal energy resources. Although the location of the plant has not yet been decided, four possible areas have been studied: East Mesa, CA; Coso Hot Springs, CA; Long Valley, CA; and Roosevelt Hot Springs, UT [Burbank, 1977]. The best site appears to be Roosevelt from an overall economic standpoint. The design is presently in the hands of an architect/engineering firm which is considering a plant of 750 MW capacity.

8.1. Site selection

The Pacific-Sierra Research Corporation has undertaken the economic studies which compare the cost of constructing and operating such a hybrid power plant at each of the four sites listed above. Table 23 gives pertinent technical information about the geothermal wells at each site and the calculated capital costs and the cost of electricity associated with the construction and operation of a 750 MW hybrid plant at the respective sites [Thomas, 1977].

8.2. Energy conversion system

Thermodynamic analysis of several possible hybrid fossil-geothermal energy conversion systems have been carried out at Brown University [DiPippo, et al, 1977; DiPippo, et al, 1978; Khalifa, et al, 1978 (A); Khalifa, et al, 1978 (B)]. Candidate systems include:

- (a) Geothermal preheat hybrid system (Fig. 29),
- (b) Fossil superheat hybrid system (Fig. 30),
- (c) Compound hybrid system (Fig. 31).

Since the geothermal fluid contains a reasonable steam fraction at the wellhead (see Sect. 6.2), the compound hybrid system may be advantageous in this case, particularly in the light of the fact that the condensed steam may be used to supply a portion of the required cooling tower make-up water.

It may also be possible to use some of the geothermal steam to beneficiate the coal which would be burned in the fossil-portion of the plant. Steam is required at a temperature of at least 150°C (300°F). The process, which involves the use of air and steam, is very effective for removing sulfur which exists in the form of pyrite and is about 50% effective in removing organically-bound sulfur. The coal for the hybrid plant would probably come from either the Wasatch or the Kaiparowits fields and contains, on the average 0.5% sulfur, with 0.1% in the form of pyrite and 0.4% organically-bound. The use of geothermal steam in this process, as opposed to boiler steam, is estimated to reduce the cost of treatment to one-third the normal cost [Floyd, 1977].

Finally, owing to the thermodynamic advantage of the hybrid plant over individual fossil and geothermal plants [DiPippo, et al, 1977], a geothermal preheat hybrid plant of 750 MW net output at Roosevelt would save 50 Mg/h (0.11×10^6 lbm/h) of coal compared to an all-coal plant of the same capacity [Thomas, 1977].

9. Other potential geothermal power plants

There are several other possible geothermal power plants which are being contemplated or in the early design stage. These are summarized briefly below [Anderson, 1977].

9.1. Flash-binary plant at Salton Sea KGRA, CA

A 50 MW plant of the flash-binary type is being considered by SDG&E, Southern California Edison and Magma Power Company at the Salton Sea KGRA. The plant would likely be patterned after the Geothermal Loop Experimental Facility (GLEF) now being operated by SDG&E [Ellis, 1978 (B)]. Figure 32 shows a typical flow diagram for the GLEF. In a power plant based on such a cycle, the by-pass valve would be replaced by an expansion engine of some type. The Salton Sea resource is hot (338°C (640°F)) but hypersaline (TDS = 250,000 - 300,000 ppm). Before a large-scale commercial power station can be installed, methods must be perfected for the proper handling of the extremely corrosive brine.

9.2. Double-flash plant at Westmorland Prospect, CA

Republic Geothermal, Inc. and MAPCO are developing the Westmorland field which lies about 14 km (9 mi) south of the Salton Sea KGRA. The reservoir temperature is about 260°C (500°F), TDS range from 20,000 - 70,000 ppm, and flow rates up to 263 Mg/h (580,000 lbm/h) of two-phase fluid have been observed. A 50 MW, double-flash or separated steam/flash plant is in the early design stage.

9.3. Single-flash plant at Brawley KGRA, CA

Union Oil Company and Chevron Oil Company are drilling at the Brawley KGRA which is about 6 km (4 mi) southeast of Westmorland. A 10 MW

single-flash or separated steam plant is being designed which will require a steam flow of about 32 Mg/h (70,000 lbm/h). The reservoir temperature is about 260°C (500°F) and the TDS is approximately 100,000 ppm, or about four times the salinity of sea water.

9.4. Double-flash plants at Desert Peak Prospect, NV

Preliminary design studies have been completed for nominal 20 MW and 50 MW double-flash plants at the Desert Peak Prospect in Nevada at the Brady-Hazen KGRA. The temperature of the reservoir appears to be in excess of 240°C (400°F), and the TDS are in the range of 6000 - 8000 ppm.

9.5. Double-boiling isobutane binary plant at Raft River KGRA, ID

A 5 MW (gross) binary plant is being designed by the Idaho National Engineering Laboratory for operation at the Raft River KGRA in Idaho [Ingvarsson, 1976]. The plant will use geothermal fluid at the relatively low temperature of 143°C (290°F), and will employ isobutane as the cycle working fluid. A simplified process flow diagram is shown in Fig. 33. Optimization studies show that the system should be designed with isobutane and two boilers, one at 116°C (240°F) or 2.63 MPa (382 lbf/in²), and one at 82°C (180°F) or 1.40 MPa (203 lbf/in²). The net output of the plant will be 3.35 MWe. Table 24 lists the cycle conditions and state properties for the nominal design case; the state points refer to those shown in Fig. 33. The plant will require about 141 kg/kW·h (310 lbm/kW·h), and have a resource utilization efficiency $\eta_u \approx 32\%$, based on a wellhead availability of 14.88 kJ/kg (34.62 Btu/lbm) and a plant output of 4.72 kJ/kg (10.99 Btu/lbm).

Although the plant will serve primarily as a test-bed for low-temperature geothermal power plants, the electricity produced will be fed into the grid of the Raft River Electrical Cooperative. The cost of electricity is estimated

to be 31.15 mill/kW·h [Ingvarsson, 1976]. It is expected that the plant will begin operations in January 1980.

10. Summary

The growth of installed electrical generating capacity using geothermal resources in the United States has been dramatic since the first 11-MW unit began operating at The Geysers in 1960. The pattern of growth is traced in Fig. 34, which includes projections of expected new generating capacity up to 1984. It is clear that by 1985 there will be 2000 MW of geothermal-based electrical generating capacity in this country. This will represent a savings of about 25 million barrels of oil equivalent over a period of one year. Furthermore, counting those states in which geothermal power plants are expected to be operating (i.e., California, Nevada, New Mexico and Utah), geothermal energy will account for about 3% of the total electricity generation. Tables 25 and 26 contain pertinent information on these estimations and projections.

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Table 1

Characteristics of mud and air drilling methods

[Weres, et al, 1977]

	<u>Mud</u>	<u>Air</u>
Hole diameter	> 444.5 mm (17.5 in)	< 317.5 mm (12.5 in)
Drilling rate	1 (reference)	4
Drill bit life	1 (reference)	2.3-4.6
Time in drilling typ. well ⁽¹⁾	7 days	14-21 days
Wear item	drill bit	drill pipe
Recovery of lost drill string	possible	impossible
Steam pressure countered by	mud weight	wellhead BOPE ⁽²⁾
Directional control	fair	poor
Directional devices	bent; kick sub	whipstock
Groundwater seepage	> several Mg/h	< a few Mg/h
Pipe cooling	good	fair
Noise (unabated)	moderate	extreme
Dust blown from well	none	great
Water use	some	some for control of dust and noise
Water pollution	possible	unlikely
Air pollution	diesel exhaust	diesel exhaust; some steam and rock dust

(1) Total drilling time is the sum of the figures shown.

(2) BOPE = Blow Out Protection Equipment.

Table 2
Composition of drilling mud as used by
Union-Magma-Thermal at The Geysers

[Reed and Campbell, 1975]

<u>Component</u>	<u>Formula</u>	<u>Percent (volume)</u>
Water	H_2O	93.09
Bentonite	$Na_{0.33}Al_{2.67}Si_{3.67}O_{20}(OH)_2$	5.39
Quebracho	organic, wood extract	0.45
Caustic soda	$NaOH$	0.32
Lignin (Tannathin)	$C_{212}H_{171}O_{41}N_3S$	0.12
Sodium bicarbonate	$NaHCO_3$	0.09
Cottonseed hulls ⁽¹⁾	organic	
Walnut shells ⁽¹⁾	organic	
Mica ⁽¹⁾	$KAl_3Si_3O_{10}(OH)_2$	

(1) Materials added to control loss of circulation by plugging the fissures causing the loss.

Table 3

Country	United States
Unit name	The Geysers, Unit 1
Owner	Pacific Gas and Electric Company
Year of start-up	1960
Plant type	Natural, direct dry steam

Turbine characteristics

Manufacturer	General Electric Company		
Type	Single-cylinder, single-flow, 6-stage, impulse-reaction		
Rated capacity	11.0 MW		
Maximum capacity	11.0 MW		
Speed	1800 rev/min		
Steam inlet pressure	647.4 kPa	93.9 lbf/in ²	
Steam inlet temperature	175.6 °C	348.0 °F	
Noncondensable gas content	< 0.3 % by weight of inlet steam		
Exhaust pressure	13.5 kPa	4.0 in Hg	
Turbine steam flow rate	108.9 Mg/h	0.240 × 10 ⁶ lbm/h	
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²	
Last stage blade height	(NA) mm	(NA) in	

Condenser characteristics

Type	Spray jet, barometric		
Pressure	13.5 kPa	4.0 in Hg	
Cooling water temperature	27.0 °C	80.6 °F	
Outlet water temperature	49.3 °C	120.8 °F	
Cooling water flow rate	2,490.0 Mg/h	5.5×10^6 lbm/h	

Table 3 (cont.)

Gas extractor characteristics

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	13.5 kPa	4.0 in Hg
Capacity	~ 593 m ³ /h	~ 349 ft ³ /min
Steam consumption	~ 4.9 Mg/h	~ 0.01 × 10 ⁶ lbm/h

Heat rejection system characteristics

Type	Counter-flow, mechanical-draft cooling tower	
Number of cells	3	
Water inlet temperature	48.8 °C	119.8 °F
Water outlet temperature	27.0 °C	80.6 °F
Design wet-bulb temperature	19.2 °C	66.5 °F
Water flow rate	2.79 Gg/h	6.15 × 10 ⁶ lbm/d
Water pump power	(NA) kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min
Fan motor power	(NA) kW	

Table 4

Country	United States
Unit name	The Geysers, Unit 2
Owner	Pacific Gas and Electric Company
Year of start-up	1963
Plant type	Natural, direct dry steam

Turbine characteristics

Manufacturer	Elliott Company		
Type	Single-cylinder, single-flow, impulse-reaction		
Rated capacity	13.0 MW		
Maximum capacity	13.0 MW		
Speed	3600 rev/min		
Steam inlet pressure	549.5 kPa	79.7 lbf/in ²	
Steam inlet temperature	175.6 °C	348.0 °F	
Noncondensable gas content	< 0.3 % by weight of inlet steam		
Exhaust pressure	13.5 kPa	4.0 in Hg	
Turbine steam flow rate	115.9 Mg/h	0.255 × 10 ⁶ lbm/h	
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²	
Last stage blade height	(NA) mm	(NA) in	

Condenser characteristics

Type	Spray jet, barometric		
Pressure	13.5 kPa	4.0 in Hg	
Cooling water temperature	27.0 °C	80.6 °F	
Outlet water temperature	49.0 °C	120.0 °F	
Cooling water flow rate	(NA) Mg/h	(NA) lbm/h	

Table 4 (cont.)

Gas extractor characteristics

Type	Steam jet ejector		
Number of stages or sets	2		
Suction pressure	13.5	kPa	4.0 in Hg
Capacity	(NA)	m ³ /h	(NA) ft ³ /min
Steam consumption	(NA)		

Heat rejection system characteristics

Type	Counter-flow, mechanical-draft cooling tower		
Number of cells	3		
Water inlet temperature	48.0 °C	118.4 °F	
Water outlet temperature	27.0 °C	80.6 °F	
Design wet-bulb temperature	18.3 °C	65.0 °F	
Water flow rate	(NA) Gg/h	(NA) lbm/h	
Water pump power	(NA) kW		
Draft fan type	Vertical, axial		
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min	
Fan motor power	(NA) kW		

Table 5

Country	United States
Unit name	The Geysers, Units 3 and 4
Owner	Pacific Gas and Electric Company
Year of start-up	1967 (Unit 3), 1968 (Unit 4)
Plant type	Natural, direct dry steam

Turbine characteristics/unit

Manufacturer	Elliott Company		
Type	Single-cylinder, single-flow, 7-stage, impulse-reaction		
Rated capacity	27.0 MW		
Maximum capacity	27.5 MW		
Speed	3600 rev/min		
Steam inlet pressure	544.0 kPa	78.9 lbf/in ²	
Steam inlet temperature	172.1 °C	341.8 °F	
Noncondensable gas content	< 0.5 % by weight of inlet steam		
Exhaust pressure	13.5 kPa	4.0 in Hg	
Turbine steam flow rate (1)	231.2 Mg/h	0.510 × 10 ⁶ lbm/h	
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²	
Last stage blade height	(NA) mm	(NA) in	

Condenser characteristics/unit

Type	Spray jet, barometric		
Pressure	13.5 kPa	4.0 in Hg	
Cooling water temperature	27.0 °C	80.6 °F	
Outlet water temperature	48.8 °C	119.8 °F	
Cooling water flow rate	2,910.0 Mg/h	6.41×10^6 lbm/h	

(1) For Unit No. 4, steam consumption is 234 Mg/h (5.157×10^5 lbm/h).

Table 5 (cont.)

Gas extractor characteristics/unit

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	13.5 kPa	4.0 in Hg
Capacity	~ 1750 m ³ /h	~ 1000 ft ³ /min
Steam consumption	~ 10.4 Mg/h	~ 0.023 × 10 ⁶ lbm/h

Heat rejection system characteristics/unit

Type	Counter-flow, mechanical-draft cooling tower	
Number of cells	6	
Water inlet temperature	48.3 °C	119.0 °F
Water outlet temperature	27.0 °C	80.6 °F
Design wet-bulb temperature	18.9 °C	66.0 °F
Water flow rate	6.58 kg/s	14.5 × 10 ⁶ lbm/h
Water pump power	(NA) kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min
Fan motor power	335 kW, rating	

Table 6

Country	United States
Unit name	The Geysers, Units 5-10
Owner	Pacific Gas and Electric Company
Year of start-up	1971 (Units 5, 6), 1972 (Units 7, 8), 1973 (Units 9, 10)
Plant type	Natural, direct dry steam

Turbine characteristics /unit

Manufacturer	Tokyo Shibaura Electric Company, Ltd. (Toshiba)		
Type	Single-cylinder, double-flow, 6 × 2 impulse		
Rated capacity	53.0 MW		
Maximum capacity	55.0 MW		
Speed	3600 rev/min		
Steam inlet pressure ⁽¹⁾	784.0 kPa	113.7 lbf/in ²	
Steam inlet temperature	179.4 °C	355.0 °F	
Noncondensable gas content	~ 1.0 % by weight of inlet steam		
Exhaust pressure	13.5 kPa	4.0 in Hg	
Turbine steam flow rate	411.7 Mg/h	0.9075 × 10 ⁶ lbm/h	
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²	
Last stage blade height	584.2 mm	23.0 in	

Condenser characteristics/unit

Type	Low-level jet, tray type		
Pressure	13.5 kPa	4.0 in Hg	
Cooling water temperature	26.7 °C	80.0 °F	
Outlet water temperature	48.0 °C	118.4 °F	
Cooling water flow rate	9,650.0 Mg/h	21.3 × 10 ⁶ lbm/h	

(1) Units 7-10: pressure is 779.1 kPa (113.0 lbf/in²).

Table 6 (cont.)

Gas extractor characteristics/unit

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	13.5 kPa	4.0 in Hg
Capacity	$\sim 3,100 \text{ m}^3/\text{h}$	$\sim 1,830 \text{ ft}^3/\text{min}$
Steam consumption	26.49 Mg/h	$0.0534 \times 10^6 \text{ lbm/h}$

Heat rejection system characteristics/unit

Type	Cross-flow, mechanical-draft cooling tower	
Number of cells	5	
Water inlet temperature	48.0 °C	118.4 °F
Water outlet temperature	26.7 °C	80.0 °F
Design wet-bulb temperature	18.3 °C	65.0 °F
Water flow rate	10.84 Gg/h	$23.9 \times 10^6 \text{ lbm/a}$
Water pump power	930 kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m^3/s	(NA) ft^3/min
Fan motor power	605 kW	

Table 7

Country	United States
Unit name	The Geysers, Units 11 and 12
Owner	Pacific Gas and Electric Company
Year of start-up	1976 (Unit 11), 1978 (Unit 12)
Plant type	Natural, direct dry steam

Turbine characteristics/unit

Manufacturer	Tokyo Shibaura Electric Company, Ltd. (Toshiba)	
Type	Tandem-compound, four-flow, 6 × 4, impulse	
Rated capacity	106.0	MW
Maximum capacity	110.0	MW
Speed	3600	rev/min
Steam inlet pressure	781.2 kPa	113.3 lbf/in ²
Steam inlet temperature	179.4 °C	355.0 °F
Noncondensable gas content	~ 1.0 % by weight of inlet steam	
Exhaust pressure	13.5 kPa	4.0 in Hg
Turbine steam flow rate	820.1 Mg/h	1.808 × 10 ⁶ lbm/h
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²
Last stage blade height	584.2 mm	23.0 in

Condenser characteristics/unit

Type	Low-level jet, tray type	
Pressure	13.5 kPa	4.0 in Hg
Cooling water temperature	26.7 °C	80.0 °F
Outlet water temperature	48.0 °C	118.4 °F
Cooling water flow rate	~ 28,500 Mg/h	~ 62.8 × 10 ⁶ lbm/h

Table 7 (cont.)

Gas extractor characteristics/unit

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	13.5 kPa	4.0 in Hg
Capacity	$\sim 6,200 \text{ m}^3/\text{h}$	$\sim 3,660 \text{ ft}^3/\text{min}$
Steam consumption	$\sim 53 \text{ Mg/h}$	$\sim 0.12 \times 10^6 \text{ lbm/h}$

Heat rejection system characteristics/unit

Type	Cross-flow, mechanical-draft cooling tower	
Number of cells	10	
Water inlet temperature	48.0 °C	118.4 °F
Water outlet temperature	26.7 °C	80.0 °F
Design wet-bulb temperature	18.3 °C	65.0 °F
Water flow rate	32.0 Gg/h	$70.6 \times 10^6 \text{ lbm/h}$
Water pump power	1860 kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m^3/s	(NA) ft^3/min
Fan motor power	1210 kW	

Table 8

Country	United States
Unit name	The Geysers, Unit 13
Owner	Pacific Gas and Electric Company
Year of start-up	1979
Plant type	Natural, direct dry steam

Turbine characteristics

Manufacturer	General Electric Company	
Type	Tandem-compound, four-flow, 5 × 4, impulse-reaction	
Rated capacity	135.0 MW	
Maximum capacity	~ 140.0 MW	
Speed	3600 rev/min	
Steam inlet pressure	786 kPa	114 lbf/in ²
Steam inlet temperature	170 °C	338 °F
Noncondensable gas content	~ 1.0 % by weight of inlet steam	
Exhaust pressure	10.2 kPa	3.0 in Hg
Turbine steam flow rate	~ 1,200 Mg/h	~ 2.64 × 10 ⁵ lbm/h
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²
Last stage blade height	426.7 mm	16.8 in

Condenser characteristics

Type	Surface, shell and tube	
Pressure	18.6 kPa	5.5 in Hg
Cooling water temperature	26.7 °C	80.0 °F
Outlet water temperature	48.0 °C	118.4 °F
Cooling water flow rate	(NA) Mg/h	(NA) lbm/h

Table 8 (cont.)

Gas extractor characteristics

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	10.2 kPa	3.0 in Hg
Capacity	(NA) m ³ /h	(NA) ft ³ /min
Steam consumption	(NA)	

Heat rejection system characteristics

Type	Cross-flow, mechanical-draft cooling tower	
Number of cells	(NA)	
Water inlet temperature	48.0 °C	118.4 °F
Water outlet temperature	26.7 °C	80.0 °F
Design wet-bulb temperature	13.3 °C	65.0 °F
Water flow rate	(NA) Gg/h	(NA) lbm/h
Water pump power	(NA) kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min
Fan motor power	(NA) kW	

Table 9

Country	United States
Unit name	The Geysers, Unit 14
Owner	Pacific Gas and Electric Company
Year of start-up	1979
Plant type	Natural, direct dry steam

Turbine characteristics

Manufacturer	Tokyo Shibaura Electric Company, Ltd. (Toshiba)	
Type	Tandem-compound, four-flow, 6 × 4, impulse	
Rated capacity	113.5	MW
Maximum capacity	117.5	MW
Speed	3600	rev/min
Steam inlet pressure	784 kPa	113.7 lbf/in ²
Steam inlet temperature	179 °C	355 °F
Noncondensable gas content	~ 1.0 % by weight of inlet steam	
Exhaust pressure	10.2 kPa	3.0 in Hg
Turbine steam flow rate	880 Mg/h	1.94×10^6 lbm/h
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²
Last stage blade height	584.2 mm	23.0 in

Condenser characteristics

Type	Surface, shell and tube	
Pressure	10.2 kPa	3.0 in Hg
Cooling water temperature	26.7 °C	80.0 °F
Outlet water temperature	48.0 °C	118.4 °F
Cooling water flow rate	32,000 Mg/h	70.6×10^6 lbm/h

Table 9 (cont.)

Gas extractor characteristics

Type	Steam jet ejector	
Number of stages or sets	2	
Suction pressure	10.2 kPa	3.0 in Hg
Capacity	(NA) m ³ /h	(NA) ft ³ /min
Steam consumption	27 Mg/h	0.06 × 10 ⁶ lbm/h

Heat rejection system characteristics

Type	Cross-flow, mechanical-draft cooling tower	
Number of cells	10	
Water inlet temperature	48.0 °C	118.4 °F
Water outlet temperature	26.7 °C	80.0 °F
Design wet-bulb temperature	18.3 °C	65.0 °F
Water flow rate	32 Gg/h	70.6 × 10 ⁶ lbm/h
Water pump power	~ 1860 kW	
Draft fan type	Vertical, axial	
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min
Fan motor power	~ 1210 kW	

Table 10

Country	United States
Unit name	The Geysers, Unit 15
Owner	Pacific Gas and Electric Company
Year of start-up	1978
Plant type	Natural, direct dry steam

Turbine characteristics

Manufacturer	General Electric Company	
Type	Single-cylinder, double-flow, 5 × 2, impulse-reaction	
Rated capacity	55.0	MW
Maximum capacity	60.0	MW
Speed	3600	rev/min
Steam inlet pressure	784.0 kPa	113.7 lbf/in ²
Steam inlet temperature	170.0 °C	338.0 °F
Noncondensable gas content	~ 1.0 % by weight of inlet steam	
Exhaust pressure	10.2 kPa	3.0 in Hg
Turbine steam flow rate	~ 500 Mg/h	~ 1.1 × 10 ⁵ lbm/h
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²
Last stage blade height	426.7 mm	16.8 in

Condenser characteristics

Type	Surface, shell and tube	
Pressure	13.5 kPa	4.0 in Hg
Cooling water temperature	26.7 °C	80.0 °F
Outlet water temperature	49.1 °C	120.4 °F
Cooling water flow rate	~ 15,900 Mg/h	~ 35.0 × 10 ⁶ lbm/h

Table 10 (cont.)

Gas extractor characteristics

Type	Steam jet ejector			
Number of stages or sets	2			
Suction pressure	10.2	kPa	3.0	in Hg
Capacity	(NA)	m ³ /h	(NA)	ft ³ /min
Steam consumption	~ 23	Mg/h	~ 0.05 × 10 ⁶	lbm/h

Heat rejection system characteristics

Type	Cross-flow, mechanical-draft cooling tower			
Number of cells	5			
Water inlet temperature	49.1	°C	120.4	°F
Water outlet temperature	26.7	°C	80.0	°F
Design wet-bulb temperature	18.3	°C	65.0	°F
Water flow rate	~ 15.9	Gg/h	~ 35 × 10 ⁶	lbm/h
Water pump power	~ 900 kW			
Draft fan type	Vertical, axial			
Air flow rate/fan	(NA)	m ³ /s	(NA)	ft ³ /min
Fan motor power	~ 625 kW			

Table 11

Country	United States
Unit name	The Geysers, Unit 16 and 17
Owner	Pacific Gas and Electric Company
Year of start-up	1981
Plant type	Natural, direct dry steam

Turbine characteristics/unit

Manufacturer	Tokyo Shibaura Electric Company, Ltd. (Toshiba)		
Type	Tandem-compound, four-flow, 6 × 4, impulse		
Rated capacity	110.0	MW	
Maximum capacity	115.0	MW	
Speed	3600	rev/min	
Steam inlet pressure	784.0 kPa	113.7 lbf/in ²	
Steam inlet temperature	169.0 °C	336.2 °F	
Noncondensable gas content	~ 1.0 % by weight of inlet steam		
Exhaust pressure	10.2 kPa	3.0 in Hg	
Turbine steam flow rate	~ 880 Mg/h	~ 1.94 × 10 ⁶ lbm/h	
Maximum allowable pressure	(NA) kPa	(NA) lbf/in ²	
Last stage blade height	584.2 mm	23.0 in	

Condenser characteristics/unit

Type	Surface, shell and tube		
Pressure	10.2 kPa	3.0 in Hg	
Cooling water temperature	26.7 °C	80.0 °F	
Outlet water temperature	48.9 °C	120.0 °F	
Cooling water flow rate	~ 32,000 Mg/h	~ 70 × 10 ⁶ lbm/h	

Table 11 (cont.)

Gas extractor characteristics/unit

Type	Steam jet ejector		
Number of stages or sets	2		
Suction pressure	10.2 kPa	3.0 in Hg	
Capacity	(NA) m ³ /h	(NA) ft ³ /min	
Steam consumption	~ 27 Mg/h	~ 0.06 × 10 ⁶ lbm/h	

Heat rejection system characteristics/unit

Type	Cross-flow, mechanical-draft cooling tower		
Number of cells	10		
Water inlet temperature	48.9 °C	120.0 °F	
Water outlet temperature	26.7 °C	80.0 °F	
Design wet-bulb temperature	18.3 °C	65.0 °F	
Water flow rate	~ 32 Gg/h	~ 70 × 10 ⁶ lbm/h	
Water pump power	~ 1860 kW		
Draft fan type	Vertical, axial		
Air flow rate/fan	(NA) m ³ /s	(NA) ft ³ /min	
Fan motor power	~ 1210 kW		

Table 12

Constituents of steam at The Geysers

[Reed and Campbell, 1975]

<u>Constituents</u>	<u>Concentration, mg/kg</u>			<u>Average flow into 110 MW unit⁽¹⁾</u>
	<u>Low</u>	<u>Average</u>	<u>High</u>	
Carbon dioxide, CO ₂	290	- 3260	- 30600	2700
Hydrogen sulfide, H ₂ S	5	- 222	- 1600	180
Methane, CH ₄	13	- 194	- 1447	160
Ammonia, NH ₃	9.4	- 194	- 1060	160
Boric acid, H ₃ BO ₃	12	- 91	- 233	75
Hydrogen, H ₂	11	- 56	- 218	46
Nitrogen, N ₂	6	- 52	- 638	43
Ethane, C ₂ H ₆	3	- 8	- 19	6.6
Arsenic, As	0.002	- 0.019	- 0.050	0.016
Mercury, Hg	0.00031	- 0.005	- 0.018	0.004

(1) Based on a steam flow of 821 Mg/h (1.81×10^6 lbm/h) to the turbine.

Table 13

Composition of gas streams from gas ejectors at The Geysers⁽¹⁾

[Reed and Campbell, 1975]

<u>Constituents</u>	Avg. concentration	Avg. flow from 110 MW unit ⁽³⁾
	<u>% by weight</u>	<u>kg/h</u>
Carbon dioxide, CO ₂	59.9	2500
Nitrogen, N ₂	25.8 ⁽²⁾	1100 ⁽²⁾
Oxygen, O ₂	8.4 ⁽²⁾	350 ⁽²⁾
Methane, CH ₄	3.8	160
Hydrogen sulfide, H ₂ S	1.2	50
Hydrogen, H ₂	0.9	38

(1) Based on measurements by PG&E of nine units over the period 1967-1974.

(2) Nitrogen and oxygen are from air entering at the turbine.

(3) Based on a steam flow of 821 Mg/h (1.81×10^6 lbm/h) to the turbine.

Table 14

Estimated emissions from cooling towers on

uncontrolled units at The Geysers

[Reed and Campbell, 1975]

<u>Constituents</u>	Avg. concentration	Avg. flow from 110 MW unit ⁽¹⁾
	<u>mg/kg</u>	<u>kg/h</u>
Ammonia, NH ₃	240	160
Carbon dioxide, CO ₂	210	140
Hydrogen sulfide, H ₂ S	200	130
Hydrogen, H ₂	12	8

(1) Based on a flow rate of 658 Mg/h (1.45×10^6 lbm/h) of water vapor from the tower.

Table 15

Maximum measurements of radon emissions at The Geysers

[Reed and Campbell, 1975]

<u>Location</u>	<u>Concentration</u> ⁽¹⁾
Steam from wells	8.3 picocurie/liter
Ejector gas from plant	5.3 microcurie/liter
Cooling tower water	0.21 picocurie/liter
Ambient air outside plant	0.026 picocurie/liter

(1) Measurements by PG&E.

Note: California Department of Health requires radon concentrations
be less than 3 picocurie/liter in uncontrolled areas.

Table 16

Capital investment by PG&E at The Geysers geothermal power project

[Dan, et al, 1975; Cossette, 1978]

<u>UNIT</u>	<u>MW</u>	<u>CUMULATIVE MEGAWATTS</u>	<u>DATE OF COMMERCIAL OPERATION</u>	<u>PG&E CAPITAL INVESTMENT</u>	<u>PG&E CUMULATIVE CAPITAL INVESTMENT</u>
1	11	11	9/25/60		
2	13	24	3/19/63	\$ 4,010,000	\$ 4,010,000
3	27	51	4/28/67		
4	27	78	3/02/68	7,610,000	11,620,000
5	53	131	12/15/71		
6	53	184	12/15/71	12,756,000	24,376,000
7	53	237	8/18/72		
8	53	290	11/23/72	10,982,000	35,358,000
9	53	343	10/25/73		
10	53	396	11/30/73	13,520,000	48,878,000
11	106	502	11/20/76	14,404,000	63,282,000
12**	106	608	7/01/78*	21,473,000*	84,755,000*
13**	135	743	7/01/79*	28,934,000*	113,689,000*
14**	110	853	2/01/79*	27,966,000*	141,655,000*
15**	55	908	9/01/78*	17,339,000*	158,994,000*
16***	110	1018	5/01/81*	42,449,000*	201,443,000*
17***	110	1128	5/01/81*	41,592,000*	243,035,000*

* Estimated

** Under Construction

*** Permits Pending

Table 17

Busbar price of electricity at The Geysers: Units 11 and 14

[Ramachandran, 1977]

	Unit 11 (Existing)	Unit 14 (Under const.)
Installed capacity, MWe (net)	110	110
Capital investment, \$/kW ⁽¹⁾	170 ⁽²⁾	232 ⁽³⁾
Required price of electricity: ⁽⁴⁾		
Capital charges, mill/kW·h ⁽⁵⁾	4.0	5.6
Operation and maintenance, mill/kW·h	0.6	0.6
Steam price, mill/kW·h ⁽⁶⁾	13.0	13.0
Total	17.6	19.2

(1) All figures are in 1976 dollars. Capital investment includes total installed plant cost, interest during construction, working capital, organization, and start-up expenses.

(2) Includes direct-contact condenser and iron catalyst treatment for H₂S abatement.

(3) Includes shell-and-tube surface condenser and Stretford H₂S abatement plant.

(4) Revenue required by the utility (PG&E) based on regulated utility economics.

(5) Conversion from \$/kW to mill/kW·h is based on 17% fixed charge rate and 80% capacity factor.

(6) By existing steam pricing formula.

Table 18

Estimated cost of condensate treatment to achieve

99% H₂S abatement at The Geysers [Ramachandran, 1977].

Method of treatment ⁽²⁾	Capital investment ⁽¹⁾		Operating cost	Total
	<u>\$/kW</u>	<u>mill/kW·h</u>	<u>mill/kW·h</u>	<u>mill/kW·h</u>
Peroxide system	9-11	0.22-0.27	0.43-1.55	0.65-1.82
Ozone system	16-35	0.4-0.9	0.44-0.72	0.84-1.62

(1) All figures are in 1976 dollars. Conversion from \$/kW to mill/kW·h is based on 17% fixed charge rate and 80% capacity factor.

(2) Both methods assume 10% of inlet H₂S concentration is dissolved in condensate; varies from 125 - 500 mg/kg of the steam. Also assumes unit equipped with integrated surface condenser and Stretford system.

Table 19

PG&E power plant reliability: geothermal versus fossil

[Matthew, 1975]

<u>Performance Factor</u>	<u>The Geysers System</u>		<u>Fossil Plants</u>	
	<u>1960-1975</u>	<u>Avg. '61-'74</u>	<u>Non-reheat⁽¹⁾</u>	<u>Reheat⁽²⁾</u>
Capacity Factor ⁽³⁾	70-96%	75.6%	24.8%	54.0%
Availability Factor ⁽⁴⁾	70-96%	86.8%	91.5%	87.6%
Forced Outage Rate	—	6.2%	1.3%	2.5%
Scheduled Outage Rate	—	7.2%	7.0%	9.8%

(1) 100 MW; Turbine inlet conditions: $P = 8.7 - 9.1 \text{ MPa (1265-1315 psi)}$;
 $T = 482-510^{\circ}\text{C (900-950}^{\circ}\text{F)}$.

(2) 165-330 MW; Turbine inlet conditions: $P = 12.5 - 16.6 \text{ MPa (1815-2415 psi)}$;
 $T = 538-565^{\circ}\text{C (1000-1050}^{\circ}\text{F)}$.

(3) Capacity factor = generation/(unit rating $\times$ period).

(4) Availability factor = (period - outage period)/period.

Table 20

Resource utilization efficiency of The Geysers units⁽¹⁾

<u>Unit No.</u>	$\frac{T_1}{^\circ\text{C } (^\circ\text{F})}$	$\frac{h_1}{\text{kJ/kg (Btu/lbm)}}$	$\frac{w^o}{\text{kJ/kg (Btu/lbm)}}$	$\frac{w}{\text{kJ/kg (Btu/lbm)}}$	$\frac{\eta_u}{}$
1	176 (348)	2792 (1200.5)	755.7 (324.9)	382.9 (164.6)	0.51
2	176 (348)	2799 (1203.2)	735.5 (316.2)	388.2 (166.9)	0.53
3	172 (341.8)	2792 (1200.2)	732.2 (314.8)	394.7 (169.7)	0.54
4	172 (341.8)	2792 (1200.2)	732.2 (314.8)	390.1 (167.7)	0.53
5-6	179 (355)	2792 (1200.4)	780.6 (335.6)	435.0 (187.0)	0.56
7-10	179 (355)	2793 (1200.6)	779.9 (335.3)	435.0 (187.0)	0.56
11-12	179 (355)	2792 (1200.5)	780.4 (335.5)	436.4 (187.6)	0.56
13	170 (338)	2769 (1190.3)	774.1 (332.8)	384.5 (165.3)	0.50
14	179 (355)	2792 (1200.4)	781.1 (335.8)	436.6 (187.7)	0.56
15	170 (338)	2769 (1190.6)	773.1 (332.4)	383.3 (164.8)	0.50

(1) Based on a sink temperature of 27°C (80°F).

(PRELIMINARY DATA)

Country	United States
Unit name	Magamax ⁽¹⁾ , East Mesa
Owner	Magma Electric Company
Year of start-up	1978
Plant type	Dual-Binary cycle

Turbine characteristics

Manufacturer	York Division of Borg-Warner Corporation	
Type	Double-flow, tandem-design, 3 × 2, radian-inflow	
Rated capacity	9.0 MW ⁽²⁾	
Maximum capacity	10.5 MW	
Speed, turbine/generator	7000/3600 rev/min	
Secondary working fluid	isobutane (i-C ₄ H ₁₀)	
S.w.f. inlet pressure	3.45 MPa	500 lbf/in ²
S.w.f. inlet temperature	174 °C	345 °F
S.w.f. exhaust pressure	0.41 MPa	60 lbf/in ²
S.w.f. exhaust temperature	110 °C	230 °F
S.w.f. mass flow rate	468 Mg/h	1.031 × 10 ⁶ lbm/h

Geothermal fluid characteristics

Inlet pressure (after pumps)	1.86 MPa	270 lbf/in ²
Inlet temperature	182 °C	360 °F
Outlet pressure (after hx's)	0.81 MPa	117 lbf/in ²
Outlet temperature	82 °C	180 °F
Mass flow rate	655 Mg/h	1.444 × 10 ⁶ lbm/h

- (1) Magmamax Process, U.S. Pat. No. 3757516.
- (2) A parallel turbine, built by Mafi-Trench, with propane as the working fluid is rated at 2.2 MW, with a maximum capacity of 3.0 MW. Propane turbine inlet conditions are 96.1°C (205°F), 3.27 MPa (474 lbf/in²); exhaust conditions are 38.9°C (102°F), 0.98 MPa (142 lbf/in²); flow rate 124.5 Mg/h (0.274 × 10⁶ lbm/h).

Table 21 (cont.)

Condenser characteristics

Type	Surface-type, shell-and-tube		
Pressure	0.41 MPa	59 lbf/in ²	
Cooling water temperature	16.7 °C	62 °F	
Outlet water temperature	26.4 °C	79.5 °F	
Cooling water flow rate	(NA) Mg/h	(NA) lbm/h	

Gas extractor characteristics

Type	(None)		
Number of stages or sets	-		
Suction pressure	- KPa	-	in Hg
Capacity	- m ³ /h	-	ft ³ /min
Power consumption	-		

Heat rejection system characteristics

Type	Phased cooling, storage ponds with sprays		
Number of cells	2 ponds		
Water inlet temperature	26.4 °C	79.5 °F	
Water outlet temperature	16.7 °C	62 °F	
Design wet-bulb temperature	14.4 °C	58 °F	
Water flow rate	(NA) Gg/h	(NA) lbm/h	
Water pump power	(NA) kW		
Draft fan type	(None)		
Air flow rate/fan	- m ³ /s	- ft ³ /min	
Fan motor power	- kW		

Table 22

Country	United States
Unit name	Heber Binary Demonstration
Owner	San Diego Gas and Electric Company
Year of start-up	1981
Plant type	Binary cycle

Turbine characteristics

Manufacturer	(To be determined)	
Type	(To be determined)	
Rated capacity	45.0	MW
Maximum capacity	65.0	MW
Speed, turbine/generator	(NA)	rev/min
Secondary working fluid	mixture: iso-butane/iso-pentane	
S.w.f. inlet pressure	3,500.0 kPa	500.0 lbf/in ²
S.w.f. inlet temperature	146.0 °C	295.0 °F
S.w.f. exhaust pressure	498.5 kPa	72.3 lbf/in ²
S.w.f. exhaust temperature	74.2 °C	165.6 °F
S.w.f. mass flow rate	3,486.8 Mg/h	7.687×10^6 lbm/h

Geothermal fluid characteristics

Inlet pressure	1,050.0 kPa	153.0 lbf/in ²
Inlet temperature	183.0 °C	360.0 °F
Outlet pressure	917.0 kPa	133.0 lbf/in ²
Outlet temperature	67.2 °C	153.0 °F
Mass flow rate	3,049.1 Mg/h	6.722×10^6 lbm/h

Table 22 (cont.)

Condenser characteristics

Type	Surface, shell and tube, single-pass, counterflow		
Pressure	498.5	kPa	72.3 lbf/in ²
Cooling water temperature	32.2	°C	90.0 °F
Outlet water temperature	42.3	°C	108.2 °F
Cooling water flow rate	30,746	Mg/h	67.783 × 10 ⁶ lbm/h

Gas extractor characteristics

Type	(None)		
Number of stages or sets	—		
Suction pressure	—	kPa	— in Hg
Capacity	—	m ³ /h	— ft ³ /min
Power consumption	—		

Heat rejection system characteristics

Type	Cross-flow, mechanical-draft cooling tower		
Number of cells	10		
Water inlet temperature	42.3	°C	108.2 °F
Water outlet temperature	32.2	°C	90.0 °F
Design wet-bulb temperature	26.7	°C	80.0 °F
Water flow rate	30.7	Gg/h	67.783 × 10 ⁶ lbm/h
Water pump power	5,000 kW (1)		
Draft fan type	Vertical, axial		
Air flow rate/fan	(NA)	m ³ /s	(NA) ft ³ /min
Fan motor power	— kW (1)		

(1) Total for water pumps and fan motors.

Table 23

Site-specific technical and economic comparisons for
a 750 MW hybrid fossil-geothermal power plant⁽¹⁾

[Thomas, 1977]

	<u>Geothermal Resource⁽²⁾</u>			
	<u>RHS</u>	<u>CHS</u>	<u>EM</u>	<u>LV</u>
Reservoir temperature, °C	274	260	200	177
Well flow rate, Mg/h	454	406	234	181
Cost per well, \$1000 ⁽³⁾	700	700	400	700
No. producing wells	5	5	9	11
Capital cost, \$/kW ⁽³⁾	489	493	533	521
Electricity cost, mill/kW·h ⁽³⁾	20.4	25.3	28.3	30.5

(1) Based on a subcritical Rankine cycle.

(2) RHS = Roosevelt Hot Springs, UT

CHS = Coso Hot Springs, CA

EM = East Mesa, CA

LV = Long Valley, CA.

(3) In 1977 dollars.

Table 24

Cycle properties for nominal design case of Raft River
isobutane binary power plant [Ingvarsson, 1976].

<u>State point</u> ⁽¹⁾	<u>Temperature</u>		<u>Mass flow rate</u>	
	<u>°C</u>	<u>°F</u>	<u>Mg/h</u>	<u>10⁶ lbm/h</u>
1	41	105	424	0.934
2	82	180	278	0.613
3	116	240	278	0.613
4	116	240	278	0.613
5	54	130	278	0.613
6	53	128	424	0.934
7	38	101	424	0.934
8	82	180	146	0.321
9	82	180	146	0.321
10	51	123	146	0.321
11	143	290	472	1.04
12	121	250	472	1.04
13	106	222	472	1.04
14	88	190	472	1.04
15	62	144	472	1.04
16	24	75	3048	6.72
17	35	95	3048	6.72

(1) With reference to Fig. 33.

Table 25

United States geothermal electric development program - to 1983

<u>Year</u>	<u>Total MWe at year end</u>	<u>New geothermal power plants</u>
1977	502.0	(None)
1978	674.2	106 MW, PG&E No. 12; 55 MW, PG&E No. 15; 11.2 MW, Magmamax dual binary
1979	929.2	135 MW, PG&E No. 13; 110 MW, PG&E No. 14; 10 MW, Republic Geothermal
1980	980.55	48 MW, Republic Geothermal; 3.35 MW, Raft River
1981	1245.55	110, 110 MW, PG&E Nos. 16, 17; 45 MW, SDG&E Heber demonstration
1982	1567.55	110, 110 MW, PG&E Nos. 18, 19; 52 MW, UP&L; 50 MW, PSNM
1983	1787.55	110, 110 MW, PG&E Nos. 20, 21.

Table 26

Projected electrical generating capacity in states
using geothermal energy in 1985

<u>State</u>	<u>Electricity generation, 10⁹ kW·h</u>			<u>Power requirement, MW</u>	
	<u>1975⁽¹⁾</u>	<u>1985⁽²⁾</u>	<u>1985⁽³⁾</u>	<u>1985⁽²⁾</u>	<u>1985⁽³⁾</u>
California	314.24	390.72	434.98	44,600	49,700
Nevada	41.08	51.08	56.86	5,800	6,500
New Mexico	61.91	76.98	85.70	8,800	9,800
Utah	18.81	23.39	26.04	2,700	3,000
Totals	436.04	542.17	603.58	61,900	69,000

(1) [Kidman, et al, 1977].

(2) Based on a 2% average annual rate of growth.

(3) Based on a 3% average annual rate of growth.

Figure captions

- Fig. 1 The Geysers: Cross-section drawn northeast and perpendicular to the major structural trend [McNitt, 1965].
- Fig. 2 The Geysers steam reservoir - an artist's impression [PG&E News Bureau (A)].
- Fig. 3 Typical well casing program - The Geysers [Reed and Campbell, 1975].
- Fig. 4 Map of The Geysers area showing location of Units 1-15 [Dan, et al., 1975].
- Fig. 5 Units 1 and 2 - The Geysers [PG&E News Bureau (B)].
- Fig. 6 Units 1 and 2, elevation view - The Geysers [Bruce, 1961].
- Fig. 7 Heat balance diagram Unit 1 - The Geysers [Bruce, 1961].
- Fig. 8 Units 3 and 4 - The Geysers [PG&E News Bureau (C)].
- Fig. 9 Heat balance diagram Unit 3 - The Geysers [Lengquist and Hirschfeld, 1976].
- Fig. 10 Heat balance diagram Units 5 and 6 - The Geysers [Matthew, 1975].
- Fig. 11 Units 5 and 6 - The Geysers [PG&E News Bureau (D)].
- Fig. 12 Units 7 and 8 - The Geysers [PG&E News Bureau (E)].
- Fig. 13 Schematic/heat balance diagram Unit 13 - The Geysers [PG&E, 1975].
- Fig. 14 Schematic/heat balance diagram Unit 14 before H₂S abatement modification - The Geysers [Ramachandran, 1977].
- Fig. 15 Schematic/heat balance diagram Unit 14 with Stretford H₂S abatement system - The Geysers [Ramachandran, 1977].
- Fig. 16 Heat balance diagram Unit 15 before H₂S abatement modification - The Geysers.
- Fig. 17 Typical flow diagram of Stretford H₂S removal process [Laszlo, 1976].
- Fig. 18 Estimated H₂S emissions from The Geysers power plants [Ramachandran, 1977].

- Fig. 19 Heat flow contours - East Mesa KGRA [BurRec, 1977].
- Fig. 20 Thermal gradient map - East Mesa KGRA [Combs, 1971].
- Fig. 21 Residual Bouguer gravity anomaly map - East Mesa KGRA: Contour values in mGal ($1 \text{ mGal} = 10 \mu\text{m/s}^2$) [Biehler, 1971].
- Fig. 22 Seismic ground-noise map - East Mesa KGRA: Contour values in dB relative to $1(\text{nm/s})^2/\text{Hz}$ in passband 3-5 Hz [Douze, 1971].
- Fig. 23 Process flow diagram for Magmamax plant - East Mesa [Anderson, 1976 (A); Hinrichs, 1978 (A)].
- Fig. 24 Plant layout diagram for Magmamax plant - East Mesa [Anderson, 1976(B); Hinrichs, 1978 (A)].
Legend: A = Brine inlet; B = Brine outlet; C = Isobutane heaters, boilers, superheaters (typ.); D = Isobutane turbine, gear box, generator; E = Recuperator; F = Isobutane condensers; G = Propane superheater; H = Propane turbine, gear box, generator; I = Propane condenser.
- Fig. 25 Process flow diagram for Heber binary demonstration plant [SDG&E, 1977 (A)].
Legend: 1 = Brine inlet, outlet; 2 = Hydrocarbon working fluid; 3 = Brine/HC heat exchanger; 4 = HC turbine; 5 = Generator; 6 = HC condenser; 7 = HC accumulator; 8 = Cooling water; 9 = Cooling tower; 10 = Cooling water make-up; 11 = Cooling tower blow-down.
- Fig. 26 (a) Process flow diagram and (b) cycle diagram for single-flash hydrothermal power plant.
- Fig. 27 (a) Process flow diagram and (b) cycle diagram for double-flash hydrothermal power plant.
- Fig. 28 (a) Process flow diagram and (b) cycle diagram for separated steam/flash hydrothermal power plant.
- Fig. 29 (a) Process flow diagram and (b) cycle diagram for geothermal-preheat hybrid fossil-geothermal power plant [DiPippo, et al., 1977].
- Fig. 30 (a) Process flow diagram and (b) cycle diagram for fossil-superheat hybrid fossil-geothermal power plant [DiPippo, et al., 1978].

- Fig. 31 Compound hybrid fossil-geothermal power plant [Khalifa, et al., 1978 (A)].
- Fig. 32 Geothermal Loop Experimental Facility - typical process flow diagram [Ellis, 1978 (B)].
- Fig. 33 Process flow diagram for Raft River double-boiling isobutane binary cycle power plant [Ingvarsson, 1976].
- Fig. 34 Growth of installed geothermal electrical generating capacity in the United States.

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Fig. 6 Units 1 and 2, elevation view - The Geysers [Bruce, 1961].

PERFORMANCE

THROTTLE FLOW lb/h 240,000
 GENERATOR ELEC. OUTPUT 12,500 kW
 AUXILIARY POWER (ELECTRICAL)
 CIRCULATING WATER PUMPS 229.0
 COOLING TOWER FANS 96.2
 EXCITER 69.0
 OTHER 7.8
 TOTAL 402 kW

NET UNIT OUTPUT 12,098 kW
 HEAT INPUT 293×10^6 Btu/h
 NET HEAT RATE 24,215 Btu/kW·h
 REFERRED TO 60 °F

CONDITIONS

GENERATOR POWER FACTOR = 1.0
 CONDENSER BACK PRESSURE 4.0" Hg
 DRY BULB AIR TEMPERATURE = 96 °F
 WET BULB AIR TEMPERATURE = 66.5 °F
 GAS SHOWN ENTERING COOLING TOWER IS AIR ABSORBED BY WATER. GASES TO-AND FROM COOLING TOWER DO NOT INCLUDE COOLING AIR BUT ONLY THAT WHICH IS ABSORBED AND DEGASSED. ANY AIR ABSORBED IN COOLING WATER IN HOT WELL IS NOT INCLUDED.

LEGEND

---- MAIN STEAM LINE
 --- WATER LINES
 - - - STEAM LINES
 - - - GAS LINES

S POUNDS PER HOUR STEAM
 W POUNDS PER HOUR WATER
 G POUNDS PER HOUR GASES
 F DEGREES FAHRENHEIT
 H STEAM ENTHALPY
 A PRESSURE PSI ABSOLUTE
 G PRESSURE PSI GASE

Fig. 7 Heat balance diagram Unit 1 - The Geysers [Bruce, 1961].

Fig. 8 Units 3 and 4 - The Geysers [PG&E News Bureau (C)].

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Fig. 11 Units 5 and 6 - The Geysers [PG&E News Bureau (D)].

Fig. 12 Units 7 and 8 - The Geysers [PG&E News Bureau (E)].

LEGEND

S= STEAM, Mg/h

W= WATER, Mg/h

H= ENTHALPY, kJ/kg

C= TEMPERATURE, °C

P= PRESSURE, kPa

Fig. 13 Schematic/heat balance diagram Unit 13 - The Geysers [PG&E, 1975].

DATA ESTIMATED FROM GEYSERS UNIT 14 DESIGN SPECIFICATIONS BEFORE STRETTFORD SYSTEM MODIFICATION.

* SOURCE OF H₂S EMISSION.

Fig. 14 Schematic/heat balance diagram Unit 14 before H₂S abatement modification - The Geysers [Ramachandran, 1977].

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Fig. 23 Process flow diagram for Magmamax plant - East Mesa [Anderson, 1976 (A); Hinrichs, 1978 (A)].

J. HILBERT ANDERSON INC. YORK, PA			
DESIGNED BY	NTS	DRAWN BY	J. E. Rogers
CHECKED BY		APPROVED BY	
PROCESS FLOW FOR MAGMAMAX PLANT MAGMA ELECTRIC CO. EAST MESA, CA			
DATE	12-18-76	PROJECT NO.	13-C-540

Fig. 24 Plant layout diagram for Magmamax plant - East Mesa [Anderson, 1976(B); Hinrichs, 1978 (A)].

Legend: A = Brine inlet; B = Brine outlet; C = Isobutane heaters, boilers, superheaters (typ.); D = Isobutane turbine, gear box, generator; E = Recuperator; F = Isobutane condensers; G = Propane superheater; H = Propane turbine, gear box, generator; I = Propane condenser.

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 condenser; 7 = HC accumulator; 8 = Cooling water; 9 = Cooling tower;
 10 = Cooling water make-up; 11 = Cooling tower blow-down.

(a) SCHEMATIC DIAGRAM

(b) CYCLE DIAGRAM

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Fig. 27 (a) Process flow diagram and (b) cycle diagram for double-flash hydrothermal power plant.

Fig. 28 (a) Process flow diagram and (b) cycle diagram for separated steam/flash hydrothermal power plant.

(a)

(b)

Fig. 30 (a) Process flow diagram and (b) cycle diagram for fossil-superheat hybrid fossil-geothermal power plant [DiPippo, et al., 1978].

Fig. 31 Compound hybrid fossil-geothermal power plant. F/S = Flasher/Separator; F = Flasher; ST1, ST2 = Steam turbine 1,2; SG = Steam generator; SH = Superheater; RH = Reheater; FSH = Fossil superheater; HPT, LPT = High-, Low-pressure turbine; GHX = Geothermal heat exchanger; FWH = Feedwater heaters [Khalifa, et al., 1978 (A)].

Fig. 32 Geothermal Loop Experimental Facility - typical process flow diagram [Ellis, 1978 (B)].

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Fig. 34 Growth of installed geothermal electrical generating capacity in the United States.