GEOTHERMAL POWER AND PROBLEMS

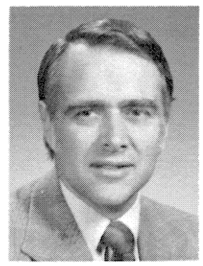
by

Terry E. McIlraith

Mechanical Engineer

Pacific Gas and Electric Company

San Francisco, California



Terry E. McIlraith is a mechanical engineer with Pacific Gas and Electric Company in San Francisco. He has been with PG and E for the past ten years and is currently the steam turbine-generator system engineer on The Geysers geothermal power plants. Previous company experience included seismic design and analysis of mechanical components for nuclear power plants, and gas turbine analysis and regenerator replacements on the Canada-California gas transmission pipeline.

Prior to joining PG and E he worked for a consulting firm designing cyclotrons, linear accelerators, nuclear weapons, and aircraft engine turbo-superchargers.

Mr. McIlraith graduated from the University of California in Mechanical Engineering, receiving his B.S. and M.S. in 1960 and 1961. He is a registered mechanical and a registered nuclear engineer in the State of California, and is a member of ASME and AOPA.

ABSTRACT

Geothermal energy is becoming an increasingly important source of electrical power in today's world. Presented here is a review of the world wide geothermal situation and the development of "The Geysers" geothermal resource by Pacific Gas and Electric Company and the companies that explore, drill wells and supply the steam. It is now the world's largest developed geothermal electric project with 15 operating units generating more than 900 megawatts. Twenty years of operating experience has demonstrated the practical and reliable features of the project.

Operating conditions differ greatly from the traditional fossil fueled thermal generating plants with boilers and clean steam. The steam produced from the wells has large quantities of gases and impurities. This geothermal steam causes unique corrosion, erosion and scale deposition problems for turbines and auxiliary equipment. The steam contains hydrogen sulphide which must be removed for a clean environment. Mountainous terrain adds to the problems of plant construction.

WORLD VIEW

Today's world is demanding more and more energy at a time when energy is becoming difficult to obtain even at higher and higher prices. One of these energy sources, geothermal energy, which is heat from the earth's core, was considered of only minor importance 30 years ago. Today it is being developed by many nations around the world as a reliable domestic energy source (Table I). It has been under development for 20 years in northern California and now provides 8% of that area's electrical energy and by 1990 will increase to 12%. Within the next two years, there will be 13 countries with commercial geothermal power. During the next 40 years, the five types of geothermal resources, described below, may be providing commercial energy (see Table II).

TABLE I. WORLDWIDE GEOTHERMAL ELECTRIC POWER AS OF JULY 1979 [10].

	No. of units in operation	Installed capacity, MW	Future capacity, MW
China	1	1	([b])
El Salvador	2	60	35
Iceland	3	32	30
Italy	37	420.6	([b])
Japan	6	165	55
Mexico	4	150	30
New Zealand	14	202.6	([b])
Philippines	3	59.2	710
Turkey	1	0.5	([b])
U.S.S.R.	1	5	([b])
United States	13	663	967.55
Total	85	1758.9	1827.55

[a]Under construction or in planning for 1982. Additional capacity may come from countries not presently using geothermal energy for electricity, such as Costa Rica, Kenya, Nicaragua, and others.

[b]Estimates not available.

Vapor Dominated Hydrothermal

Vapor dominated hydrothermal is saturated or superheated steam generated by underground water and heated by hot magma from the earth's core (Figure 1). The first commercial vapor dominated hydrothermal plant went into operation in 1913 at Lardarello, Italy. Japan and the United States (at the Geysers in California) now have commercial plants using this resource (Figures 2 and 3).

Wells are drilled to obtain the steam trapped in the earth. This steam is created from water heated by the hot magma deep in the earth. The steam is generally in the 300-400°F range at about 100 to 150 psig when it reaches the surface. This steam is passed through moisture and particulate separators on its way to the steam turbine. Cooling towers are used to cool the condensate for condenser operation. There is 20% excess condensate in this system which is pumped back into the earth using an injection well. Therefore, there is no makeup water required for power cycle cooling requirements.

There are problems with this type of plant. The steam contains hydrogen sulfide which must be removed to meet environmental requirements of various governmental agencies. Also, the condensate is very corrosive. The separators do not remove all of the solids which cause erosion of turbine blades and nozzles. There are only a few known sites in the world that can provide dry steam.

TABLE II. CLASSIFICATION OF RESOURCES FOR GEOTHERMAL POWER APPLICATIONS [4].

Resource	Temperature Characteristic	Salinity*	First Commercial Operation
Hydrothermal			
Vapor dominated	340° to 385°F	-	1913
Liquid dominated	300° to 600°F	0.1-26%	1958
Geopressured	300° to 400°F	4-10%	1986
Hot dry rock	300° to 600°F	-	1990
Magma	1,200°F	-	2020+

*Note: seawater about 3.5%

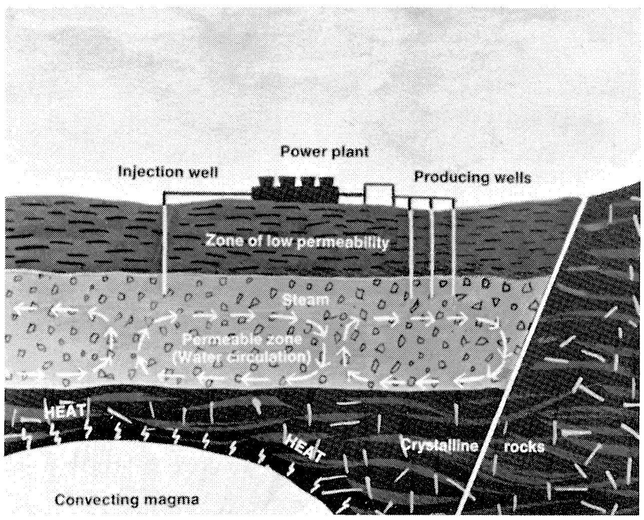


Figure 1. Geothermal Energy Cycle where Heat from the Earth's Core is Conducted to Water-Bearing Strata and Generates Steam.

Liquid Dominated Hydrothermal (Brine)

Liquid dominated hydrothermal is hot water or brine under pressure in the 300°F to 600°F temperature range. The first commercial liquid dominated hydrothermal plant is located at Wairakei, New Zealand, and began operation in 1958.

The well drilling is similar to the vapor dominated wells except that the liquid is more corrosive than the steam. There are several processes available for utilizing this resource type.

a. Flash Steam Process

The Wairakei plant uses the flashed steam process (Figure 4). This process uses one or two stages of flashing. The pressures are generally less than 100 psig and more mass flow is required for the same amount of energy as compared to the vapor dominated hydrothermal process. The turbines are also larger (and more expensive) to accommodate the large volumetric flow rate of steam. The steam usually contains noncondensible gases which must be removed and processed before venting to the atmosphere. The liquids are corrosive and the precipitation of minerals can be a problem.

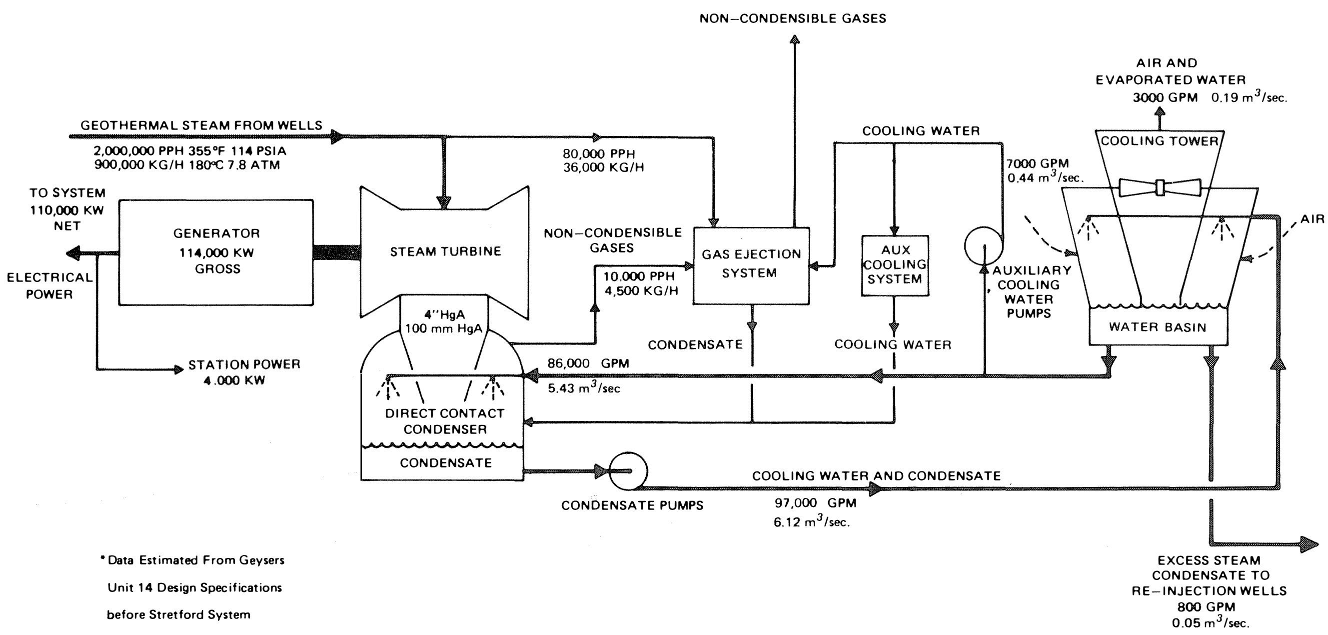


Figure 2. Typical Geysers Power System Cycle without Stretford H_2S Abatement System. This a Vapor Dominated Hydrothermal 110,000 kW Net Capacity Unit.

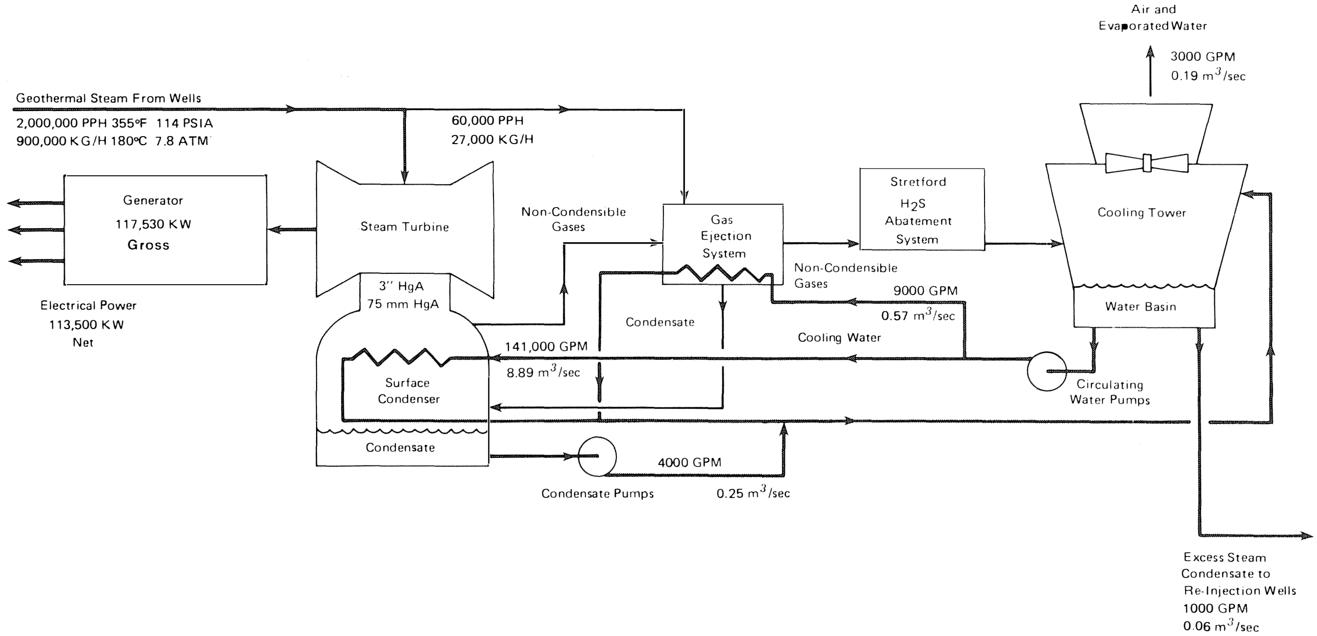


Figure 3. Typical Geysers Power System Cycle with Stretford H_2S Abatement System. This is a Vapor Dominated Hydrothermal 110,000 kW Net Capacity Unit.

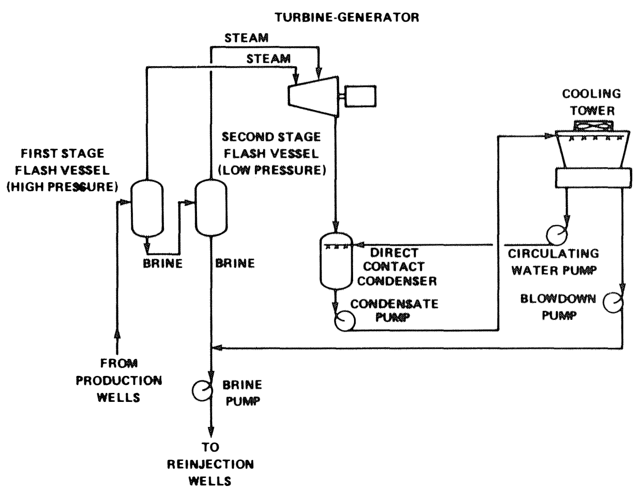


Figure 4. Typical Two Stage Flash Steam Process for a Liquid Dominated Hydrothermal Unit. [4]

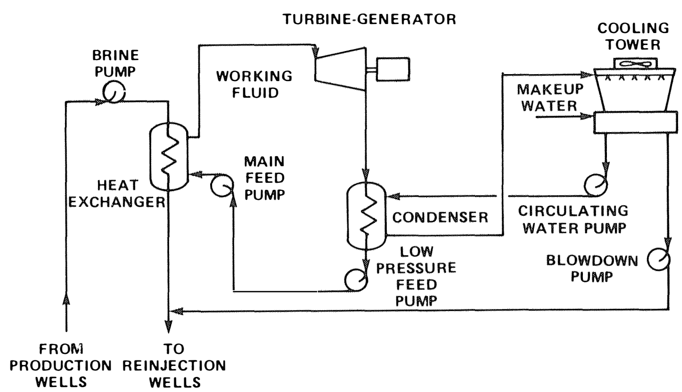


Figure 5. Typical Binary Process for a Liquid Dominated Hydrothermal Power Plant. [4]

b. Binary Process

The binary process is especially useful with low temperature brine in the 212-380°F range. The process is a closed Rankine cycle using a working fluid heated in a heat exchanger (boiler) by hot geothermal brine (Figure 5). The working fluids are usually light hydrocarbons with a low boiling temperature. There are pilot plants now in operation in Japan and the U.S. at East Masa, New Mexico. This process can use a lower well head temperature brine. It reduces the brine to a lower exit temperature than in the flashed process yielding more energy per pound of brine used. A more compact turbine can be used. The geothermal fluids do not enter the turbine, reducing contaminates associated with maintenance problems. Since 100% of the brine passes through the heat exchanger and is then reinjected into the earth, there is no air pollution problem from hydrogen sulfide or other noncondensible gases. The cooling tower requirements are greater for the binary process over the flashed process because of lower desired turbine exhaust temperatures. Scaling in the heat exchanger on the brine side can also be a problem.

Experimental work is being done on a direct contact heat exchanger which would eliminate the scaling problem, reduce the heat exchanger cost, and give a closer approach temperature of the two fluids. There would be some loss of the working fluid and some carry-over of the brine and noncondensible gases into the turbine adding to the operating cost.

c. Hybrid Combustion

A study was made of the possibility of using geothermal brine in a standard fossil fuel plant where the brine would preheat the boiler feedwater before entering the boiler. Also considered was using the flashed steam process with a fossil fueled boiler to superheat the clean flashed steam. There are many practical problems to be solved such as solids carry-over, H_2S removal, making fossil fuel available at a geothermal site, and others.

Geopressure

The geopressure energy exists in hot brine containing dissolved natural gas under high pressure. It is found at depths from 8,000 feet down to as much as 30,000 feet. The abnormally high pressures are due to the fluid being at the greater depths and being trapped and forced to support the earth above it. The temperatures are about 325°F and pressures as great as 15,000 psi are found. The natural gas is in the range of 20 to 25 cubic feet/barrel of brine. The natural gas may be recovered in separators which operate at pressures above the saturation pressure of the fluid in order to reduce water vapor carry-over. The hydraulic pressure may be converted to useful energy using hydraulic turbines to drive generators. The heat energy of the brine may be recovered as described above under liquid dominated hydrothermal (Figure 6).

The problems with this resource are, as expected, erosion, corrosion, scaling, and extreme well-head pressures that can lead to well blowout. In addition, unique to this resource, there are possible problems of land surface subsidence, induced seismicity, and fluid disposal at shallower depths.

The Gulf Coast area, continuous from Mexico to Mississippi, has large potential geopressure deposits.

Hot Dry Rock

Hot dry rock is a rock system that has insufficient natural water but contains sufficient heat energy conducted from the earth's core at a high enough temperature to be of commercial interest. These rocks will require that water injection wells be drilled and the rock fractured in order to recover the energy from production wells. It is estimated that much more geothermal energy may be obtained from hot dry rock than from all of the hydrothermal energy that may be available. Field test work is being done in this area by Los Alamos Scientific Laboratory, Albuquerque, New Mexico.

Magma

Magma energy is stored in the form of hot molten rock, at about 1200°F, deep in the earth. Test drilling is now being done in Hawaii. The plan is to insert a heat exchanger into the hot magma.

LOCAL VIEW ("THE GEYSERS")

History

The Pacific Gas and Electric Company (PGandE) Geysers Power Plant is now the world's largest developed geothermal field with 15 operating units generating 908 megawatts of power. The first attempt at developing this field, located north of San Francisco, occurred in the early 1920's. A small company was formed, and eight shallow wells were drilled. Two ten horsepower reciprocating steam engine generators were installed to supply lighting for a local resort. However, the equipment could not withstand the scaling, corrosive, and abrasive effects of the natural steam. Also, the time was not right as California had sufficient low cost hydroelectric power available.

There are not true geysers in this field. Geysers are water spouts. Only natural steam vents or fumaroles are found here. It is a vapor dominated hydrothermal field.

In 1955 the Magma Power Company drilled a very successful well. Then in cooperation with the Thermal Power Company, more wells were drilled which had a combined capacity of 300,000 lbs/hr of steam at 115 psig with a small amount of superheat. Commercial use of this steam appeared feasible, and in 1958 a contract was signed with Pacific Gas and Electric Company to build an eleven megawatt plant. Pacific Gas and Electric Company bought an old discarded turbine

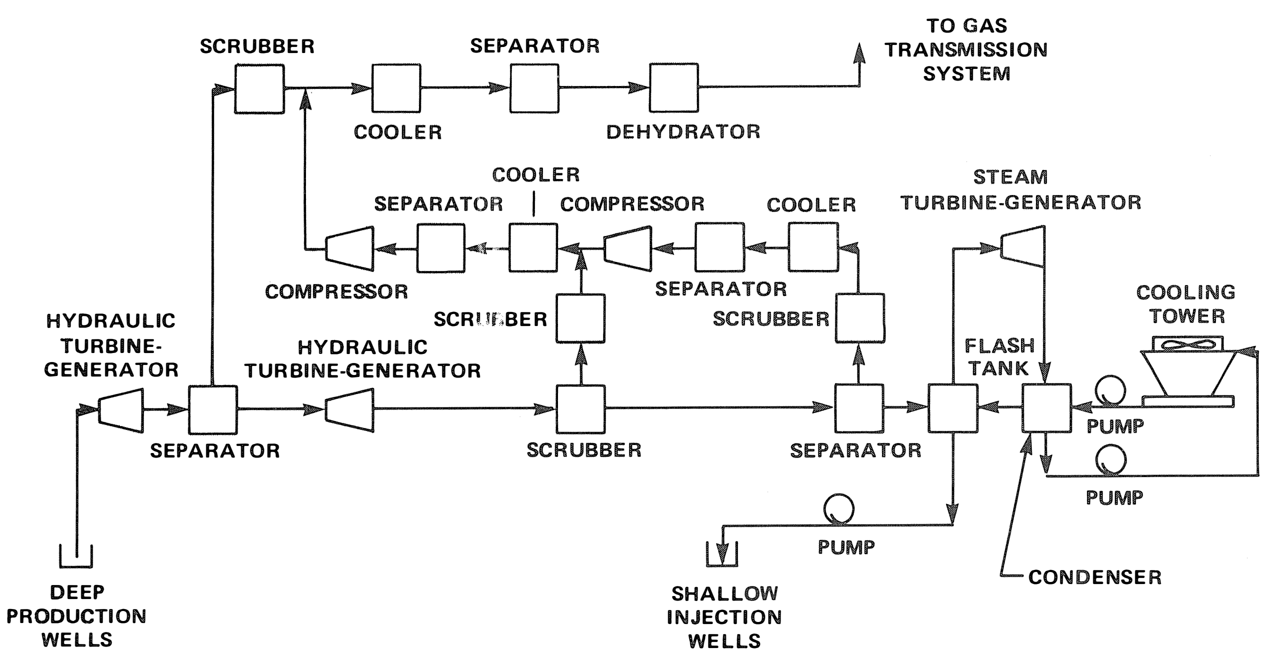


Figure 6. Flow Diagram for Geopressured Gas and Power Plants. [5]

generator that had previously been owned and operated by the company to power a street car line. The refurbished equipment went on line in 1960 and is still operating. However, its output is only a little more than 1% of the current total field capacity. Today the wells are still drilled by other companies, and the steam is sold to PG and E under contract (Table III).

Drilling, Gathering, and Reinjection

The average well now being drilled at the Geysers produces 150,000 lbs/hr of steam. Most of the units now being built are rated at about 110 megawatts net output and require 2,000,000 lbs/hr of steam or about 14 wells initially. The production of the wells decline with time. Therefore, additional wells must be drilled during the 30-year plant life (Figures 7 and 8). The additional wells are drilled at a rate of about one every year and a half. We expect that a total of about 35 wells will be needed during the plant's lifetime.

The wells are now drilled on 20 to 40 acre plots. Therefore, 700 to 1,400 acres are required for each 110 megawatt plant. The wells must be within one mile of the plant to keep heat and head losses low. This is why there are many small plants instead of one large one at the Geysers site. The new wells now average about 7,500 feet in depth with a maximum of 10,000 feet.

The cost of drilling a 5,000 foot well is $2\frac{1}{2}$ times that of a 2,500 foot well. One 10,000 feet deep is four times that of the 5,000 foot well. Also, the 10,000 foot well has greater friction losses and typically produces only 80 percent as much as a 5,000 foot well.

A typical well is drilled in four steps. The first 200 feet is a 26 inch hole in which 20 inch diameter casing is cemented in place. Then down to about 2,000 feet a $17\frac{1}{2}$ inch hole is drilled with a $13\frac{3}{8}$ inch diameter cemented casing. Next the well is drilled to a depth of 4,000 or 5,000 feet stopping near the top of the steam zone. This part is a $12\frac{1}{4}$ inch hole with a $9\frac{5}{8}$ inch cemented casing. Then, an $8\frac{3}{4}$ inch hole is drilled on down into the steam bearing strata. Additional casing is installed at the top of the well for added safety. The top 200 feet of the well is finished with a total of three layers of steel and cement.

The geological formations in geothermally active areas generally contain harder rock than found in drilling for gas and oil. This is true of the Geysers field. This hard rock causes extremely low penetration rates even with special drilling bits. Also the higher temperatures and the corrosive effect of gases and fluids decrease the life of the drilling equipment. The top part of the well is drilled using conventional drilling mud to circulate the drill bit cuttings to the surface. The lower part of the hole, where the steam is, is at a very low pressure so the

TABLE III. PACIFIC GAS AND ELECTRIC COMPANY THE GEYSERS POWER PLANT DEVELOPMENT

Date of Commercial Operation	Unit Number	Net Kilowatts	Cumulative Net Kilowatts	Steam Supplier	Original Plant Cost	Cumulative Original Plant Cost	Location (County)
Sep 25, 1960	1	11,000	11,000	U-M-T)	$	$	Sonoma
Mar 19, 1963	2	13,000	24,000	U-M-T) –	3,802,000	3,802,000	Sonoma
Apr 28, 1967	3	27,000	51,000	U-M-T)			Sonoma
Nov 2, 1968	4	27,000	78,000	U-M-T) –	7,534,000	11,336,000	Sonoma
Dec 15, 1971	5	53,000	131,000	U-M-T)			Sonoma
Dec 15, 1971	6	53,000	184,000	U-M-T) –	11,953,000	23,289,000	Sonoma
Aug 18, 1972	7	53,000	237,000	U-M-T)			Sonoma
Nov 23, 1972	8	53,000	290,000	U-M-T) –	11,953,000	35,242,000	Sonoma
Oct 15, 1973	9	53,000	343,000	U-M-T)			Sonoma
Nov 30, 1973	10	53,000	396,000	U-M-T) –	13,492,000	48,732,000	Sonoma
Nov 20, 1975	11	106,000	502,000	U-M-T	19,737,000	68,471,000	Sonoma
Mar 1, 1979	12	106,000	608,000	U-M-T	35,000,000*	103,471,000*	Sonoma
Jun 17, 1979	15	55,000	663,000	Thermogenics	36,000,000*	139,471,000*	Sonoma
May 15, 1980	13	135,000	798,000	Aminoil	54,000,000*	193,471,000*	Lake
Aug 1980#	14***	110,000	908,000	U-M-T	59,000,000*	252,471,000*	Sonoma
Aug 1982#	17***	110,000	1,018,000	U-M-T	68,000,000*	320,471,000*	Sonoma
Oct 1982#	18***	110,000	1,128,000	U-M-T	70,000,000*	390,471,000*	Sonoma
Nov 1983#	16##	110,000	1,238,000	Animoil	89,000,000*	479,471,000*	Lake
Dec 1984###	20*#	110,000	1,348,000	U-M-T	86,000,000**	565,471,000**	Sonoma
Aug 1986###	19###	55,000	1,403,000	---	60,000,000**	625,471,000**	---
Aug 1986###	21###	110,000	1,513,000	---	98,000,000**	723,471,000**	---

KEY: Steam Developers: U-M-T — Union Oil, Magma Power & Thermal Power Companies
Thermogenics — Thermogenics, Inc.
Aminoil — Aminoil USA, Inc.

* Estimated
** Forecast
*** Under Construction
\# Scheduled
\## Permits Pending
\### Planned
*# Site Selection in Progress

NOTE: Net kilowatts is gross kilowatt rating less estimated station use.

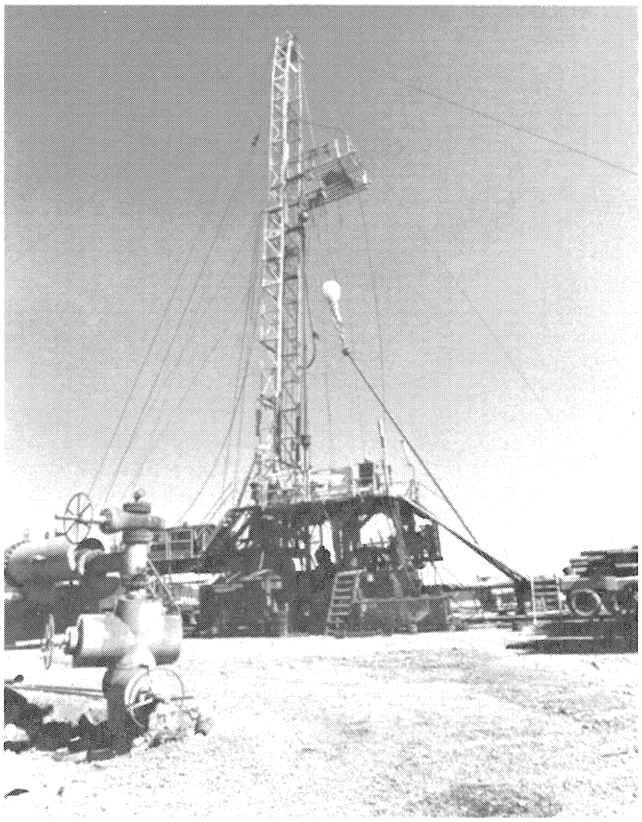


Figure 7. 150 Foot Tall Well Drilling Rig at The Geysers. The Rig is Portable and the Hinged Derrick is Self-erecting.

mud will not come back to the surface. Also, the mud would bake hard at the temperatures encountered. Therefore, the conventional mud tanks, pumps, blenders, and shakers are replaced at this point by air compressors, rock traps, and mufflers. The drill bit cuttings are blown back to the surface by the air. As the well deepens, it becomes a mixture of air and steam traveling at near sonic velocities. The high speed particles cause extreme erosional wear on the equipment.

After a well is completed, it is never completely shut in. During periods when the steam is not needed, it is allowed to bleed to the atmosphere at about one-half of one percent of the well's normal production rate. If a well was completely shut in, the steam would condense at the top and the liquid would fall back into the well. This would cause rocks to fall off the sides of the hole. Before it could be put back into production, it would have to be cleaned out so that the rocks and particles could not be carried down stream to the separators or possibly beyond to the steam turbine. Also, if the well was completely shut in, the casing would cool and shrink giving rise to stresses on the casing and cement. Therefore, it is important to keep the well hot at all times by bleeding a small amount of steam.

The gathering system consists of pipelines, valves, relief valves, and moisture and particle separators (Figures 9 and 10). The pipelines range in size from 10 inches at the well heads up to 42 inches at the power plants. These pipelines are designed for expansion with loops and slide shoes on pipe supports. The expansion can be as much as 14 feet for a mile of pipeline. Near each well head is a separator to remove moisture and solids. There is very little moisture at the well head. Additionally, there are moisture and solids separators on each of the steam lines just before they enter the power plant. These separators are horizontal centrifugal types that are 99% efficient in removing particles 10 microns and larger in size.

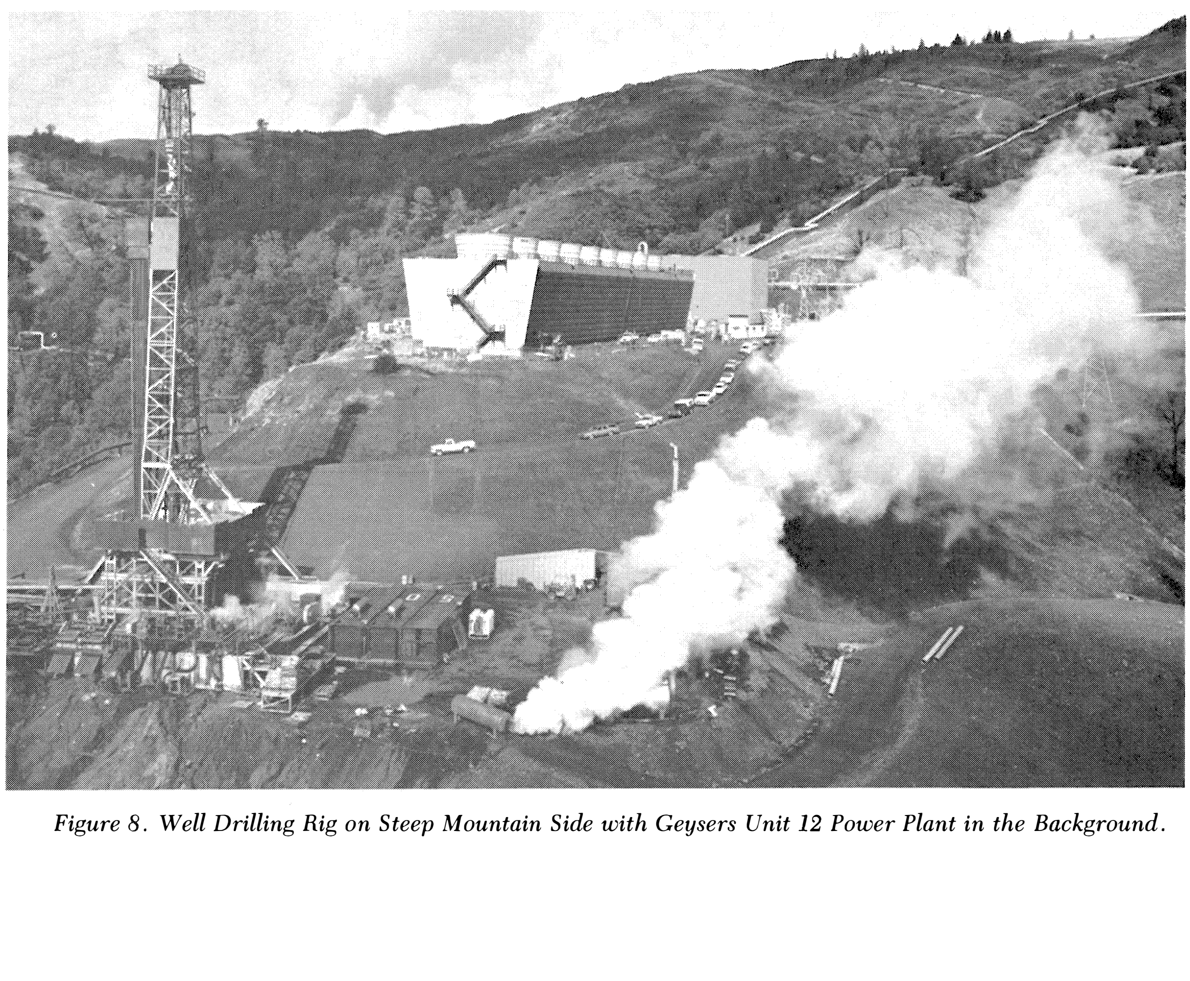


Figure 8. Well Drilling Rig on Steep Mountain Side with Geysers Unit 12 Power Plant in the Background.

Figure 9. Geysers Units 3 and 4 Showing Steam Gathering System with Expansion Loops.

Figure 10. Mountainous Terrain of The Geysers Power Plant with Units 5 and 6 on the Left and Units 3 and 4 on the Right.

The well head pressures reach 480 psig when shut in. The pipeline is designed for 150 psig. Therefore, for emergency shut downs, a relief valve designed to pass the full flow opens releasing the steam through a large pit filled with rocks to muffle the sound.

The power plant operation is such that 80 percent of the steam condensate is evaporated and 20 percent must be reinjected into the field. This water cannot be discharged into the local streams that have domestic or agricultural use, so the water is pumped from a holding tank to an injection well. The steam pressure is about 500 psi at the bottom of the well. Therefore, these wells, which are 4,000 feet or more deep, accept the water without having to use pumps.

Regulation

It takes about nine years to complete one project. Much of this time is required for regulatory procedures. There are permits required from numerous governmental agencies for drilling wells, building gathering systems, obtaining right-of-ways for transmission lines, and building the power plant. An attempt has been made to standardize the turbine-generators and their buildings on four of the units now being built in order to speed up the design, procurement, and installation stages.

Plant Site Selection

Typically three potential sites are evaluated based upon the following considerations:

1. It is desirable to have the site within one mile of the producing wells to minimize energy loss.
2. The layout of surface features is planned for blending harmoniously with the environment as much as is practical. In the rugged terrain of the Geysers, suitable sites with minimum exposure are very limited and a thorough evaluation of alternate sites is necessary.
3. The power plant must be located on a competent foundation material, away from surface faulting and existing or potential slide hazards. Thorough geological and soil investigations are performed with holes drilled to a depth below proposed foundation levels. The technical advice of geologists is vital at this step.
4. The site should have the most economical overall site development evaluation. This requires provisions for:
   a) Easy accessibility by all weather roads with not over 10% grade, without excessive cuts into steep ridges, and constructed on stable material.
   b) Availability of land which does not conflict with interests of government agencies or private parties.
   c) Proximity to a transmission line corridor.
   d) Minimum excavation.

In principle, the site selection should represent an optimum solution of a cost/benefit analysis, wherein costs and benefits of construction and costs and benefits of environmental factors are weighed and balanced.

Construction

Construction on a unit starts during the dry season after regulatory approval of the project is received. The construction of a typical 110 megawatt plant requires approximately 30 months. The work occurs in three major phases: (1) site preparation, (2) foundation and building construction, and (3) equipment installation.

The construction of a typical 110 mW power plant, excluding transmission line and towers, requires about 4,000 cubic yards of concrete, 270 tons of reinforcing steel, and 240 tons of structural steel. Excavation of a plant site is primarily a balanced cut-and-fill operation. The volume of excavated material ranges from 70,000 to 150,000 cubic yards.

Two to three months are required to clear and grade the site. This must be accomplished during the dry season to minimize site erosion. Excavation and placement of foundations require about six months. Concrete batch plants are set up at each site and removed after the turbine pedestal is constructed. Water must be hauled to the batch plants. Water within three miles is considered almost on site.

Structural steel is shop fabricated in the San Francisco Bay area. Erection of the structural steel requires about three months. The erection of the cooling tower overlaps the structural steel work and requires about three months to complete.

Electrical and mechanical equipment is delivered to the site about a year after site preparation begins. Major equipment components are assembled during the installation phase. The generator stator is the largest single piece of equipment, weighing about 140 tons for a 110 mW unit. Transporting the stator up the last 16 to 20 miles of winding mountain road takes about 48 hours.

The largest stator installed is at Unit 13 and weighs 166 tons. This 158 mVA generator stator was transported on three connected flat deck trailers having eleven pairs of steerable axles with a total of 88 wheels (Figure 11). The rig has no motive power but does have a hydraulic system which permits independent steering of each pair of axles and lateral leveling of the deck. A large temporary crane is installed at the site to lift the major turbine-generator components into place. Assembly and installation of the plant equipment, piping, conduits, and cables take about twelve months. Testing and, finally, commercial operation of the unit begins about two years after the start of site preparation (Figures 12 and 13).

Figure 11. Transporting the 166 Ton Geysers Unit 13 Generator Stator Up Steep Mountain Roads to the Plant Site.

Mechanical Equipment

The most thermodynamically efficient use of the dry steam resource at the Geysers is to expand it directly through a steam turbine (Figure 3). The exhaust from the turbine enters

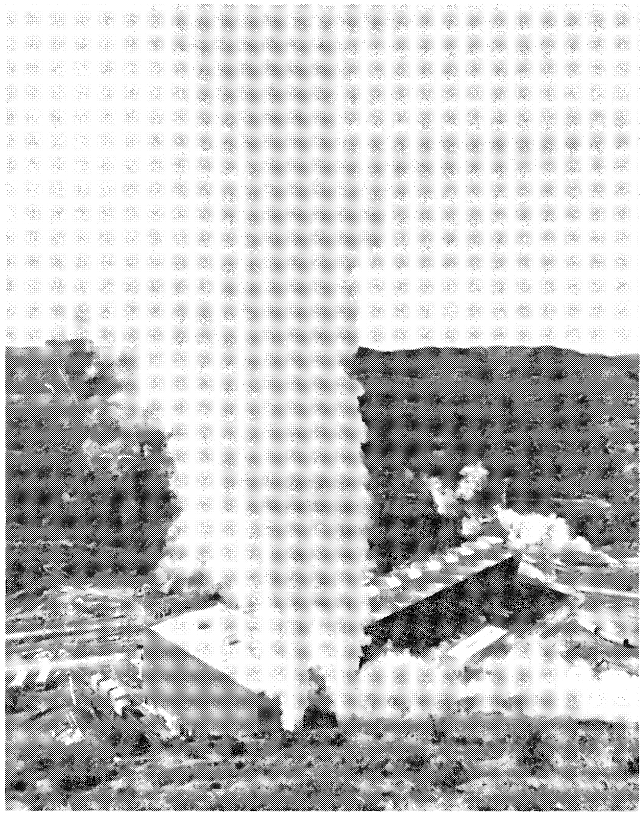


Figure 12. Geysers Unit 11 during Steam Blow Prior to Initial Start-up. This is Required to Clean Out Construction Debris from Pipes.

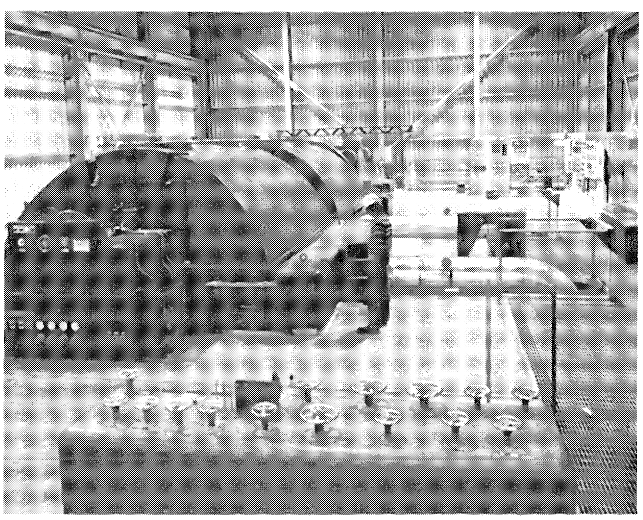


Figure 13. Interior View of Geysers Unit 12 Showing Valve and Gauge Panel in the Foreground and the Front Standard of the Tandem Steam Turbines with the Generator in the Background.

a condenser cooled by water from a cooling tower. The condenser also creates a vacuum by condensing the steam leaving the turbine. This almost doubles the energy extracted from the steam as compared to exhausting directly to the atmosphere. Steam operated gas ejectors remove the noncondensible gas from the condenser. The amount of gas removed is as much as 5,000 times that removed from a conventional fossil-fired plant of the same size, and approximately 4% of the steam is used to operate the gas removal system.

In the newer plants, the steam enters the turbine at 338 to 355°F and 114 psia, expands through the turbine, and exhausts into a condenser designed to operate at about 3 inches Hg absolute. More energy may be extracted by lowering the condenser pressure. However, there is a lower limit that is controlled by the temperature of the available cooling water. The lack of surface water sources for cooling requires the use of cooling towers. To lower the temperature of the cooling water requires more expensive cooling towers. Also, the condenser becomes larger and more costly. As exhaust pressures are lowered below 3 inches Hg absolute, the steam velocity in the last turbine stage becomes excessively high causing increased erosion from moisture and particulate impingment on the blading and nozzles.

The induced draft cooling towers have been designed for a wet bulb temperature of 65°F. This value is exceeded less than three percent of the time. When it is, the cooling water temperature rises and so does the turbine exhaust pressure reducing the output of the unit.

The condensers on the first four units are of the barometric (high level) direct contact type. Direct contact condensers mix the cooling water with the steam exhaust using spray nozzles. The first four units are 11 to 27 megawatts. Units 5 through 12 are 55 to 110 megawatts and the height and size of a barometric condenser for these would be impractical. These units use low level direct contact condensers with the turbine exhaust discharging downward directly into the condenser in a conventional manner. The direct contact condensers trap much of the noncondensible gases in the water and carry them to the cooling towers where the gases then escape to the environment. Starting with Unit 13 and the units now being built, surface condensers similar to condensers in conventional fossil fuel power plants are used. The noncondensible gases are ducted from the surface condenser to a hydrogen sulfide abatement facility.

Steam from the wells is relatively noncorrosive. However, at the point where condensation starts, corrosion becomes a problem. Therefore, most equipment down stream of the turbine is made of stainless steel. The turbine blades are made of 12% chrome steel which is resistant to erosion and corrosion and has improved vibration damping characteristics. Because of the corrosive steam/moisture, the fatigue limit is considerably lowered. For this reason, the blade width is increased to reduce the bending stress due to the steam force (Figures 14 through 19).

The blades have radial drain grooves at stages where moisture is expected to form (Figure 20). These grooves are intended to prevent moisture from impinging on the next stage. The last stage has the outer portion of the blades stellite-clad to protect it from moisture erosion.

The nozzles are also made of chrome steel. The diaphragms are made of steel plate instead of a casting to facilitate repair of eroded and corroded parts. The nozzles are welded to the diaphragms and have pockets built into them for removing moisture.

The turbine rotor is a forging made of alloy steel without nickel which is sensitive to the corrosive environment. The casings are made of carbon steel. The turbines are steam sealed by conventional methods.

The 55 megawatt turbines are single two-flow turbines. The 110 to 135 megawatt turbines are two coupled, two-flow

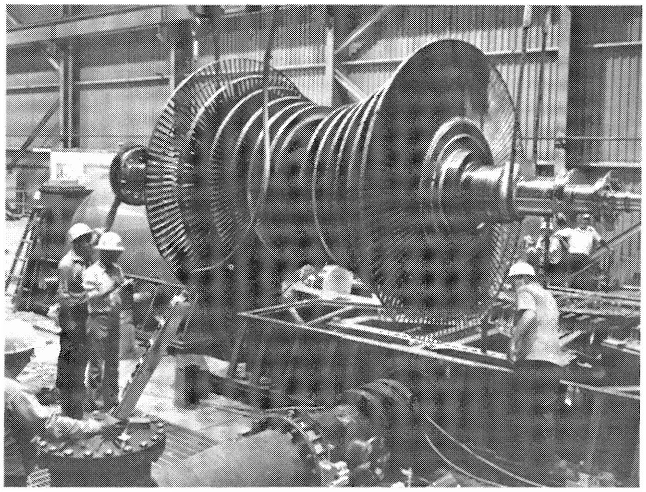


Figure 14. Installing Turbine Rotor at Geysers Unit 9.

turbines sometimes referred to as four-flow turbines. The heat rate is typically between 21,000 and 22,000 Btu per kilowatt-hour. This is high as compared to a fossil unit and is due to the low temperatures and pressures of the available geothermal steam.

The units are unmanned and have automatic controls which will shut them down in an emergency and purge the generator of the hydrogen coolant. These units are run as base-load (maximum capacity) generation sources since they are the lowest cost generation source after hydroelectric plants. Also, it is not practical in terms of well maintenance to vary the steam flows.

Hydrogen Sulfide Abatement

The noncondensable gases in the steam at The Geysers are, in addition to causing equipment problems, an air pollution problem (Table IV). The main problem gas is the toxic noncondensable hydrogen sulfide (H_2S). A metallic catalyst system using iron has been installed on many of units built before Unit 13. This system uses iron sulfate in the

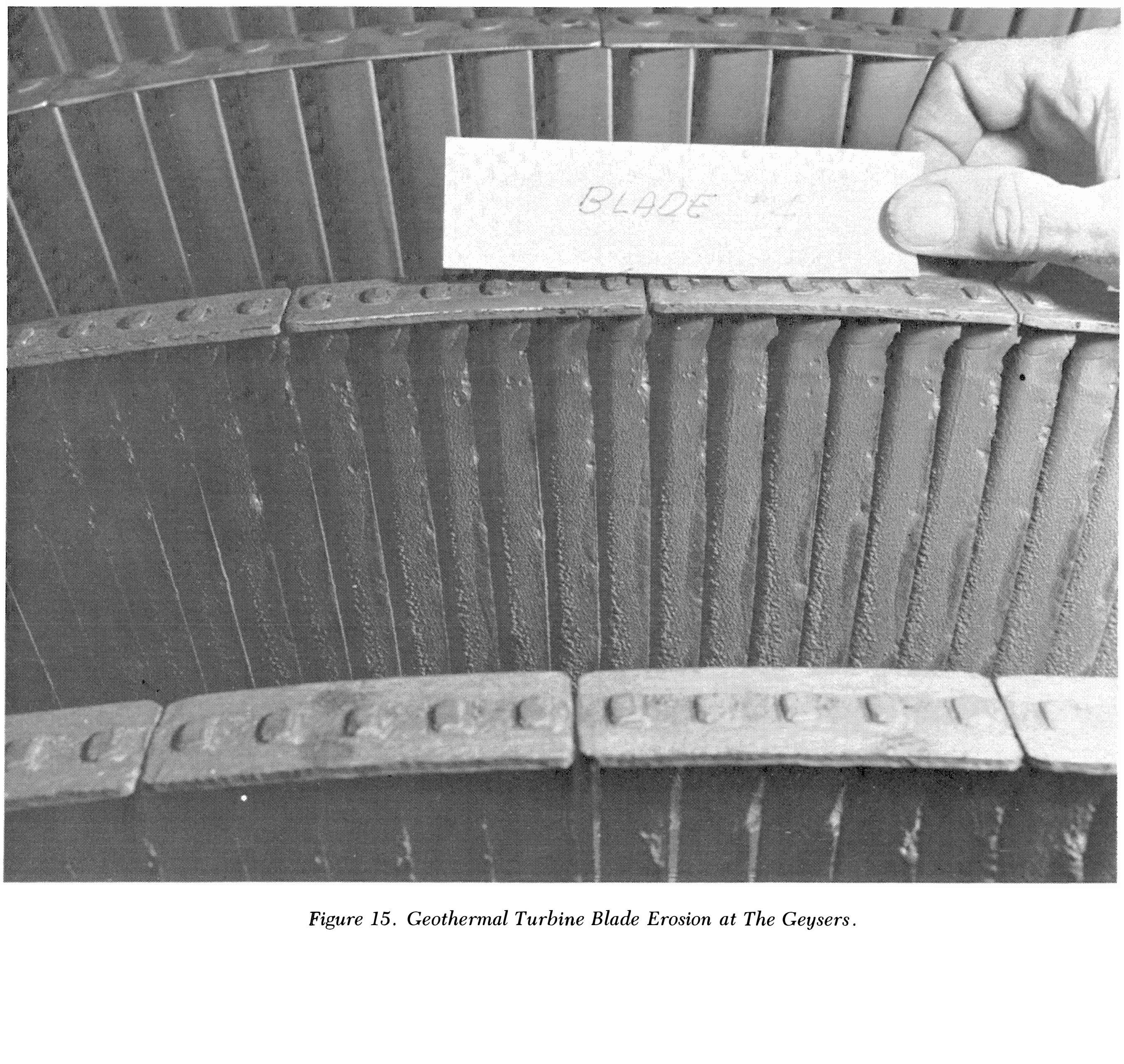


Figure 15. Geothermal Turbine Blade Erosion at The Geysers.

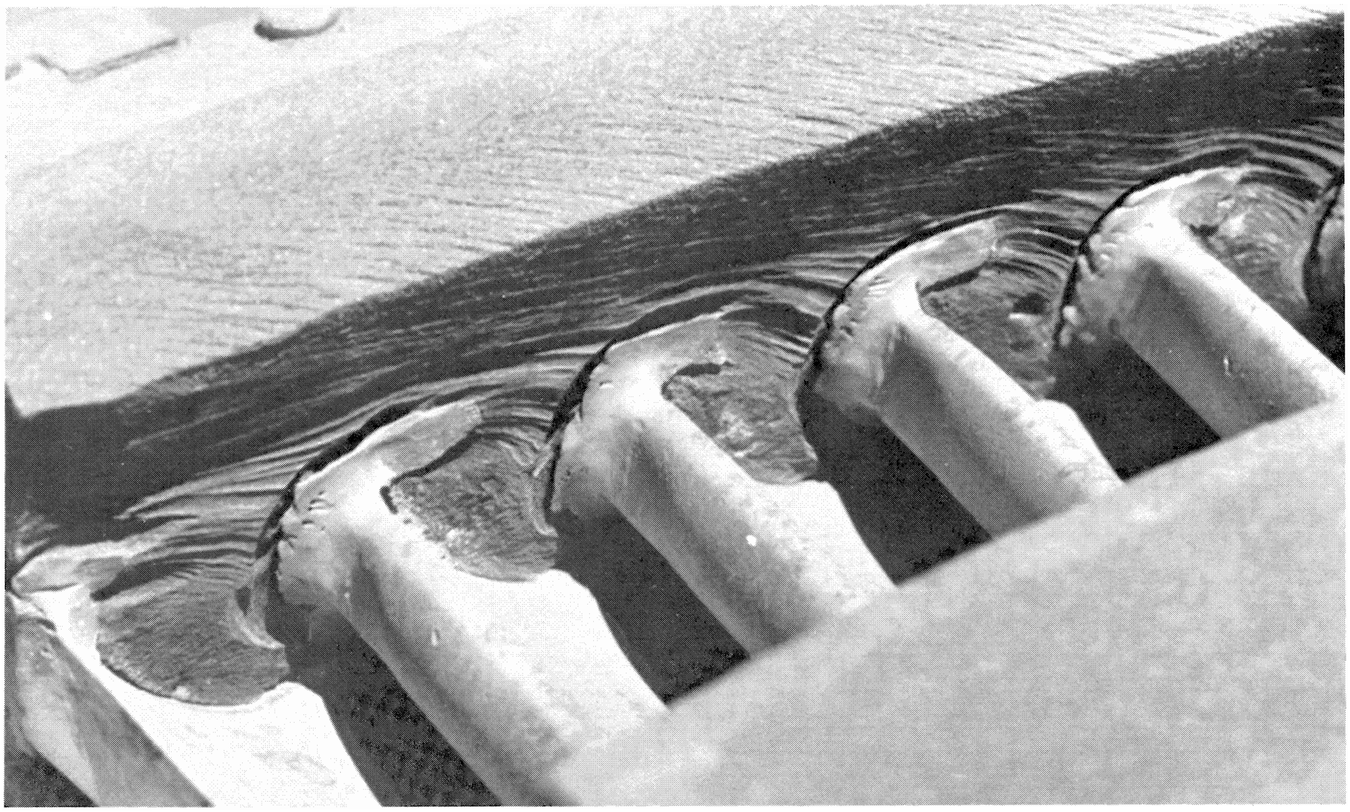


Figure 16. Turbine Nozzle Diaphragm Erosion at The Geysers. The Nozzles are Made of Chrome Steel and the Diaphragms are Carbon Steel Plate. This One has Seen Seven Years of Service.

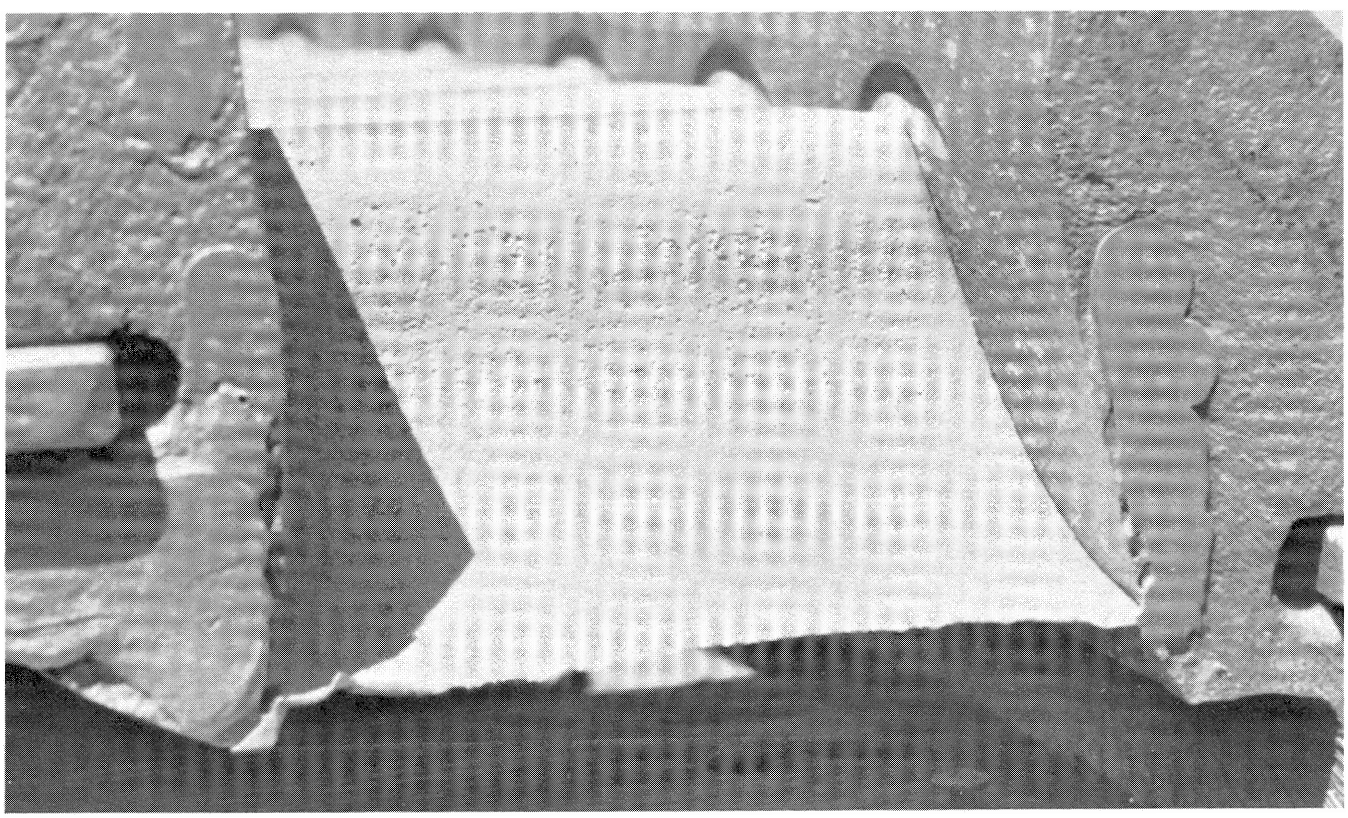


Figure 17. Erosion Pitting of Steam Turbine Nozzle Surface After Seven Years of Service at The Geysers.

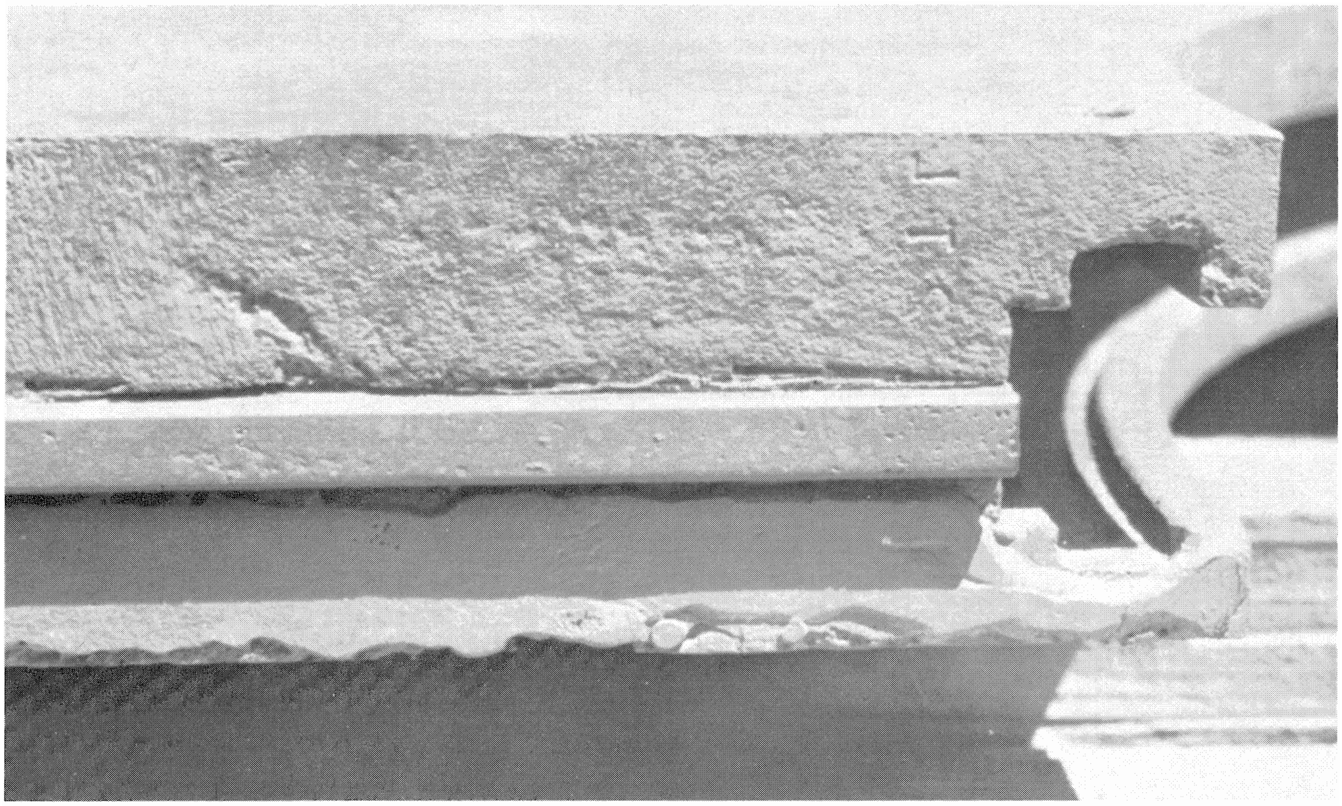


Figure 18. Corrosion of Diaphragm Parting Line Surface After Seven Years of Service at The Geysers.

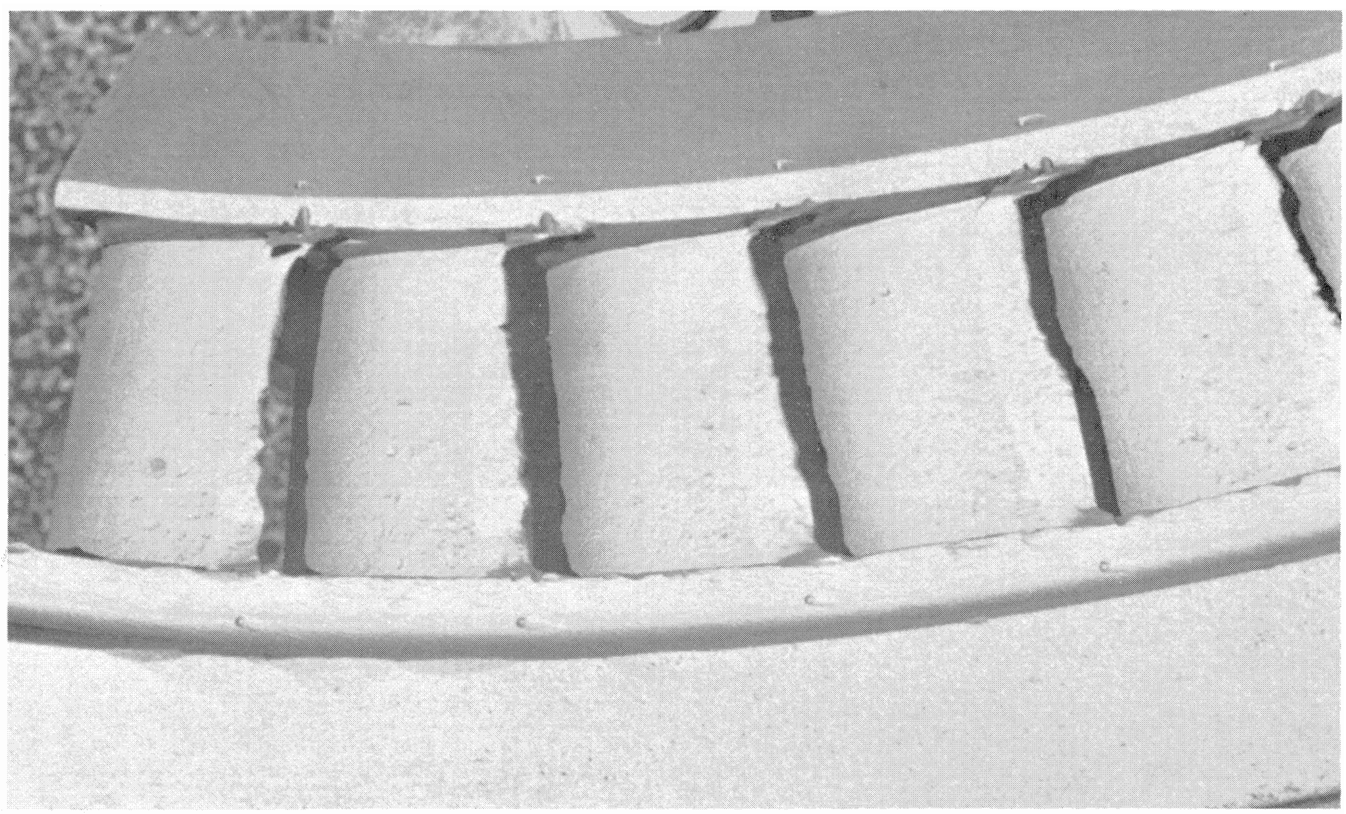


Figure 19. Erosion of the Nozzles of a Steam Turbine at The Geysers After Seven Years of Service.

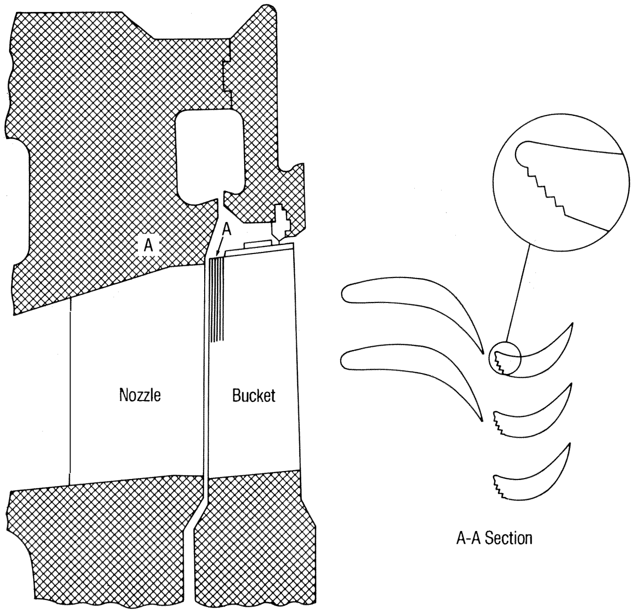


Figure 20. Turbine Nozzle and Blade Showing Moisture Drain Grooves.

TABLE IV. NONCONDENSIBLE GAS COMPOSITION AT THE GEYSERS [14]

Gas	Range	Field average
Carbon dioxide	55-86%	78%
Methane	1-10%	5%
Hydrogen sulfide	2- 7%	5%
Ammonia	2- 8%	6%
Hydrogen	1- 3%	2%
Nitrogen	1-30%	4%
Argon	trace	trace
Radon	trace	trace
Total noncondensibles	0.1%-2%	0.54%

Notes:
1. Individual components are expressed as per cent by weight of total noncondensibles.
2. Total noncondensibles are expressed as per cent by weight of total steam flow.

cooling water to remove the H_2S. However, it was found that the catalyst could not be regenerated quickly enough and the sludge formed in the circulating water system created troublesome equipment problems. Also the water became more corrosive to the equipment. This required installation of an expensive sludge removal system.

In order to meet the abatement requirements, caustic soda and hydrogen peroxide are added to the circulation water along with the iron catalyst. This abatement method is far from satisfactory and methods of upstream abatement (upstream of the turbine) are now being tested in pilot plants.

An upstream abatement system could have a side benefit of reducing equipment corrosion problems. One method involves a large heat exchanger where the steam is condensed; the gases drawn off, and the condensate then reboiled. A second upstream method removes the H_2S by scrubbing the steam with a copper sulfate solution.

Units 13 and after are equipped with the Stretford system (Figures 21 and 22). This is a downstream system where the gas is separated from the steam condensate in the condenser. This requires the use of a surface condenser where a higher fraction of the gas may be separated from the steam than in the direct contact type. The gas is processed in the Stretford equipment where the H_2S is washed with an aqueous solution containing sodium carbonate, sodium vanadate, and anthraquinone disulfonic acid (ADA). The process converts the H_2S to elemental sulfur and then separates the sulfur from the solution. The solution is regenerated and reused. Even though the Stretford process works quite well, some H_2S dissolves in the condensate and is released to the atmosphere in the cooling tower. Several secondary abatement methods are being considered to solve this problem. One of them is being used at Units 13, 14,

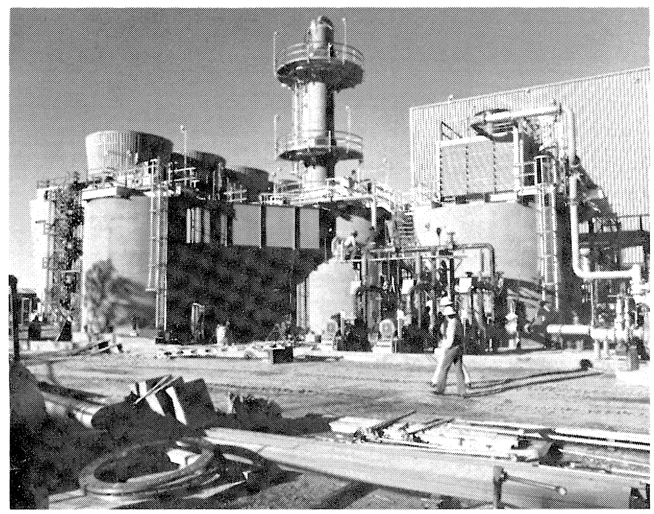


Figure 21. Geysers Power Plant Unit 15 During Construction. The Stretford H_2S Abatement Facility is in the Foreground.

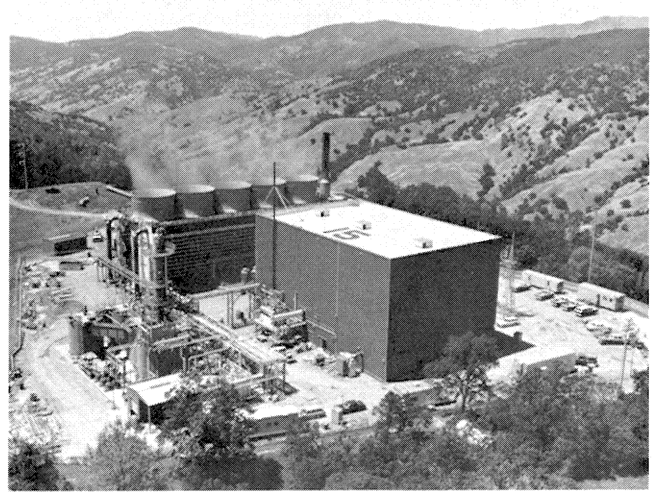


Figure 22. The 57,000 kW Net Geysers Unit 15. The Stretford H_2S Abatement Facility is in the Left Foreground.

and 15. This is a hydrogen peroxide — iron catalyst method. The hydrogen peroxide oxidizes the dissolved H_2S to soluable sulfates which are reinjected into the wells.

SUMMARY

Experience has already shown geothermal power generation to be a commercial success. In spite of the problems mentioned above, it is an attractive generation source that will be developed worldwide. Since it is domestic energy, any nation developing geothermal power will reduce its dependence on foreign energy sources and help its balance of trade/payments position. In 1980 The Geysers Power Project will eliminate the need in Northern California for about nine million barrels of oil annually. This could grow to twenty million annually by 1990. Much research is now being done in many areas of geothermal energy. As economic pressure for energy grows and as technical advancements are made, the growth of energy available from the earth's core may be phenomenal.

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