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**MATERIALS SELECTION GUIDELINES FOR
GEOTHERMAL ENERGY UTILIZATION
SYSTEMS**

*485 - Bins
25 - NTIS
2781 - Special*

By
Peter F. Ellis, II
Marshall F. Conover

January 1981

Work Performed Under Contract No. AC02-79ET27026

Radian Corporation
Austin, Texas

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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FOR
GEOTHERMAL ENERGY UTILIZATION
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by

Peter F. Ellis, II
Marshall F. Conover

Prepared for:

United States Department of Energy
Division of Geothermal Energy
Washington, D.C. 20545

under

Contract No. DE-AC02-79ET27026

January 1981

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QUICK REFERENCE SITE LOCATOR

EL SALVADOR	AHUACHAPAN
ICELAND	HIGH TEMPERATURE AREAS
	LOW TEMPERATURE AREAS
ITALY	BORACIFEROUS REGION
JAPAN	HATCHOBARU
	MATSUKAWA
	OTAKE
MEXICO	CERRO PRIETO
NEW ZEALAND	BROADLANDS
	WAIRAKEI
UNITED STATES OF AMERICA	BACA, NM
	BRADY HOT SPRINGS, NV
	CASA DIABLO, CA
	EAST MESA, CA
	HEBER, CA
	KLAMATH FALLS, OR
	MADISON AQUIFER, SD
	RAFT RIVER, ID
	SALTON SEA, CA
	THE GEYSERS, CA
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January 1981
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1.0 INTRODUCTION

This manual is prepared for the Department of Energy's Division of Geothermal Energy by Radian Corporation under DOE Contract No. DE-AC02-79ET27026. The manual includes geothermal fluid chemistry, corrosion test data, and materials operating experience. Systems using geothermal energy in El Salvador, Iceland, Italy, Japan, Mexico, New Zealand, and the United States are described. The manual provides materials selection guidelines for surface equipment of future geothermal energy systems when used as shown in Figure 1.0-1.

FIGURE 1.0-1. DETERMINATION OF MATERIAL SELECTION GUIDELINES

1.1 Background

The goal of the National Geothermal Program is to promote the development of geothermal energy as an economically effective, reliable, operationally safe, and environmentally acceptable alternative energy source. One aspect of geothermal development that merits attention is materials reliability. The objectives of the materials work in DOE's Division of Geothermal Energy are (1) identification of reliable materials for geothermal applications and (2) reduction of materials costs where they have a significant effect on the cost of geothermal energy use.

Materials-related problems can limit any technology in terms of cost, reliability, and downtime. Geothermal energy systems are no exception, and it is therefore prudent to examine corrosion and other materials problems. The availability of durable, cost-effective materials for systems that process geothermal fluids definitely affects geothermal energy development.

1.2 Purpose

This manual is a collection and interpretive summary of data on materials performance in various geothermal fluids. The information may alleviate lengthy testing of large numbers of materials at each new geothermal site. It provides help in screening potential construction materials using past experiences, and provides some guidelines for selecting materials for surface equipment of future geothermal energy systems.

The manual also establishes a framework of background information that defines an approach to materials selection. It identifies the utilization modes and equipment used to produce electricity and process heat, discusses the importance of fluid chemistry, and defines the forms and mechanisms of corrosive attack that have been observed in geothermal process streams.

1.3 Scope

Geothermal resources include steam-dominated sources, liquid-dominated sources, geopressurized sources, and hot dry rock sources. There are numerous geothermal resource areas in the world. Some resources in the U.S. which have potential for utilization as direct thermal or indirect electrical energy have been designated known geothermal resource areas (KGRA's).

This manual considers materials performance in liquid- and steam-dominated world resources with maximum temperatures within the economic electric power generation and direct utilization ranges. Predictions about the corrosiveness of fluids from these resources can be made based on the fluid characteristics. Fluid and steam transmission lines, separators, heat exchange and energy conversion equipment, heat rejection equipment, and surface components of disposal systems are considered.

Useful data on materials performance are the results of process industries operations using saline fluids as well as geothermal power plants and direct utilization systems. Materials performance data are available for seawater desalination plants, foreign operating geothermal power plants (in Iceland, Italy, Japan, Mexico, and New Zealand), and The Geysers, a U.S. power plant utilizing a steam-dominated resource. Materials performance data are also available from direct utilization systems in the United States and abroad. The selection of suitable materials which will withstand a specific corrosive environment is technologically and economically complex. This manual provides technological guidance for such materials selection in above-ground systems. Economic assessment is outside the scope of this manual.

This manual supersedes and replaces Materials Selection Guidelines for Geothermal Power Systems (DeBerry, Ellis and Thomas 1978) and

contains all of the data presented in that document, which considered seven liquid-dominated resources in the United States.

1.4 Selection Guidelines

Substantial information must be considered in selecting reliable construction materials. Once a geothermal resource is selected, the mode of extraction of the heat energy can be specified. Selection of the mode is based on the physical and chemical characteristics of the resource. The process steps in a given use-mode and the composition of the fluid define specific process stream characteristics (e.g., chemical composition, temperature, pressure, and fluid velocity). This knowledge is essential because it defines the various environments in which construction materials will be subject to corrosion.

The next step is to consider the results of previous materials performance tests and the operating experience in existing facilities. This information helps predict which materials will be most resistant to attack under the specific conditions in each process stream. It is important to consider whether the test conditions or operating conditions are the same as those in the process stream of interest. It is also necessary to consider all the possible modes of failure for materials in geothermal fluids. The effects of fabrication practices, equipment configuration, and stresses during operation must also be taken into account. Using these sources of information, materials can be selected, or the need for further testing can be defined.

Most corrosion failures are caused by well known phenomena. Minimizing these failures often depends upon understanding the environment to which the materials are exposed and being aware of past materials experience. Close cooperation is required between corrosion and design engineers who must consider the characteristics of the geothermal resource, the use mode to be applied, the durability of potential materials under these conditions, and the economic effect of materials selections. Materials considerations should continue from the design phase through plant construction and start-up to operation.

1.5 Overview

The information in this manual is presented in five sections and seven appendices.

Section 2 identifies the key chemical species that are significant in determining corrosiveness of geothermal fluids. Geothermal fluids are complex, variable mixtures whose characterization is difficult but essential if materials tests results are used to predict materials performance in other systems. Seven key corrosive species that are responsible for the corrosiveness of geothermal environments are presented.

Section 3 defines the utilization modes of geothermal energy as well as the various physical fluid parameters that affect corrosiveness. Diagrams of nine possible power cycles for the generation of electricity from geothermal fluids are presented. One power cycle is applicable to steam-dominated resources, five are for liquid-dominated sources recovered by natural pressure, and three are for liquid-dominated sources recovered by pumping. General fluid properties that influence the applicability of power cycles to a particular geothermal resource are discussed. The corrosiveness of individual process streams in power cycles is described in terms of pressure, velocity, and temperature variations. Finally, two basic modes for direct utilization of geothermal energy are addressed, and factors influencing the choice of direct use modes are explored.

Section 4 presents both detailed and summarized results of materials performance tests and applicable operating experiences from forty-six sites throughout the world. Each site section begins with a description of the geothermal resources' chemical and physical parameters. This is followed by a summary of the site's materials test data. Test methods are discussed along with test results. Actual operating experiences relative to materials problems are given for many geothermal power plants. These experiences are particularly important to designers of future facilities since failures and problem areas may not be encountered during short-term materials tests.

Section 5 discusses the application of various non-metallic materials in geothermal environments.

The seven appendices are: (A) Corrosion Behavior of Specific Alloy Classes in Geothermal Fluids, (B) Corrosion in Seawater Desalination Plants, (C) Worldwide Geothermal Power Production, (D) DOE-sponsored Utilization Projects, (E) Plant Availability, (F) Relative Costs of Alloys, and (G) Composition of Alloys.

REFERENCE

DeBerry, D.W., Ellis, P.F., and Thomas, C.C, 1978. Materials Selection Guidelines for Geothermal Power Systems, DOE Contract No. EG-77-C-04-3904, NTIS Pub. Code ALO-3904-1, Austin, TX, Radian Corporation.

2.0 CORROSIVE AND SCALE-FORMING SPECIES IN GEOTHERMAL PROCESS STREAMS

The corrosiveness of geothermal streams is a complex interaction between fluids (their chemistry, temperature, velocity, and pressure) and materials used in geothermal systems. In Section 2.1, several factors which control the corrosive nature of the geothermal fluid are identified, and the effects of each factor are discussed.

Section 2.2 is a brief discussion of scale-forming constituents of geothermal fluids, including silica, calcium carbonate, and calcium sulfate.

2.1 Key Corrosive Species

Geothermal fluids contain several chemical species that have a significant effect on the corrosion of metallic construction materials. These key species, which were identified from corrosion literature and data on chemical composition of fluids from liquid-dominated geothermal resources, are as follows.

- Oxygen
- Hydrogen ion (pH)
- Chloride ion
- Hydrogen sulfide
- Carbon dioxide species
- Ammonia species
- Sulfate ion

A quantitative prediction of their corrosive effects is complicated by the following factors.

- Different materials respond to the same fluid component in different ways and to different degrees.
- The interaction of two or more chemical species may give results different from those obtained with the individual species.
- The importance of a species depends on the form of attack (uniform corrosion, pitting, crevice corrosion, stress corrosion cracking, or corrosion-fatigue).

Other components that are less common or aggressive can also produce corrosive effects in some geothermal fluids. Examples are fluoride ion, heavy metals, and boron.

The following paragraphs briefly summarize Appendix A, Corrosion Behavior of Specific Alloy Classes in Geothermal Fluids. Table 2.1-1 is an index to Appendix A and can be used to locate more detailed discussions on the effects of the corrosive species.

Oxygen - Dissolved oxygen is the most serious contaminant of geothermal fluid, steam, and condensate. It cannot exist in thermodynamic equilibrium with hydrogen sulfide and therefore is not a normal component of most geothermal fluids. Aeration of geothermal fluids has been shown to cause a tenfold or greater increase in the uniform corrosion rate of carbon steel in many geothermal environments. The introduction of just 30 ppb oxygen can quadruple the corrosion rate of carbon steel in a geothermal fluid (Ellis 1980). The effect of oxygen on the uniform corrosion rate of other materials is less well known.

Oxygen contamination may cause localized corrosion by forming occlusion cells (oxygen concentration cells or aeration cells). In conjunction with chloride ions at certain temperatures, oxygen can cause pitting of some stainless steels without forming occlusions. Under these conditions, oxygen will also promote crevice corrosion. Less than 100 ppb dissolved oxygen can cause stress corrosion cracking of some austenitic stainless steels in geothermal fluids.

A few materials, especially aluminum alloys, require some dissolved oxygen to maintain their passivation films. Such alloys may corrode severely in oxygen-free geothermal streams.

Hydrogen Ion (pH) - In most oxygen-free geothermal environments, the corrosion of carbon and low alloy steels is largely controlled by the reduction in hydrogen ions. The corrosion rates of these steels decrease rapidly as pH increases, as illustrated for AISI 1020 steel in Figure 2.1-1.

Decreasing pH also affects many corrosion-resistant alloys. Passivity is often pH-dependent, and loss of passivity may allow pitting, crevice corrosion, or stress corrosion cracking.

Chloride Ion - The uniform corrosion rate has been shown to be proportional to the square root of the chloride ion concentration (Foley 1970), or

$$\text{Mils/yr} = K (\text{ppm Chloride})^{\frac{1}{2}}$$

where K is a proportionality constant. This relationship is valid where the solution is neutral, air-free, and near ambient temperatures, and the chloride ion concentration ranges from less than one to 18,000 ppm. The validity of the relationship has not been demonstrated at elevated temperatures.

TABLE 2.1-1. MAIN ENVIRONMENTAL FACTORS AND LOCATIONS IN APPENDIX A
OF FURTHER DISCUSSION

MAIN ENVIRONMENTAL FACTORS	MATERIAL	EFFECT	LOCATION IN APPENDIX A
Oxygen	Mild and low alloy steels	Uniform corrosion	A.1.1, Figure A.1-1
		Pitting and crevice corrosion	A.1.1.1
		Fatigue endurance limits	A.1.2.2
	Stainless steels	SCC	A.2.1.2.1
	Titanium alloys	Pitting and crevice corrosion	A.3.1.2.1
Hydrogen Ion (pH)	Mild and low alloy steels	Uniform and localized corrosion	A.1.1.1
		Uniform corrosion	A.1.1.1, Figure A.1-4
		SCC	A.1.1.2
		SSC	A.1.1.3.6
	Stainless steels	Pitting and crevice corrosion	A.2.1.1.2
		SCC	A.2.1.2.1, Figure A.2-6
	Titanium alloys	Pitting and crevice corrosion	A.3.1.2.2, Figure A.4-2
	Copper alloys	SCC	A.5
Chloride Ion	Mild and low alloy steels	Uniform, pitting and crevice corrosion	A.1.1.1.2, Figure A.1-5 Figure A.1-6
		SCC	A.1.1.2
		SSC	A.1.1.3.7
		Uniform and localized corrosion in geo-thermal steam	A.1.2.1
	Stainless steels	Pitting and crevice corrosion	A.2.1.1.1, Figure A.2-1
		SCC	A.2.1.2, A.2.1.2.1, Figure A.2-5
		SCC in condensate	A.2.3
	Titanium alloys	Pitting and crevice corrosion	A.3.1.2.1, Figure A.4-1
		SCC	A.3.1.4
Hydrogen Sulfide	Mild and low alloy steels	Uniform, pitting, and crevice corrosion	A.1.1.1.4
		SCC	A.1.1.3
		Hydrogen blistering	A.1.1.4
		Corrosion fatigue	A.1.2.2
		Erosion-corrosion in steam lines	A.1.2.3

TABLE 2.1-1. (Continued)

MAIN ENVIRONMENTAL FACTORS	MATERIAL	EFFECT	LOCATION IN APPENDIX A
Carbon Dioxide	Stainless steels	Pitting and crevice corrosion	A.2.1.1.4
		SSC	A.2.1.4
	Nickel alloys	SSC and hydrogen embrittlement	A.4.1.3
	Copper alloys	Uniform corrosion	A.5
	Cobalt alloys	SSC resistance	A.6.1
	Mild and low alloy steels	CO ₂ vapor pressure and flow rate effect on design	A.1.1
		Uniform, pitting and crevice corrosion	A.1.1.1.4
		Corrosion fatigue	A.1.2.2
	Stainless steels	Pitting and crevice corrosion	A.2.1.1.4
	Mild and low alloy steels	Uniform corrosion	A.1.1.1.4
Ammonia	Stainless steels	Uniform, pitting and crevice corrosion	A.2.1.1.4
	Copper alloys	SCC, "season cracking"	A.5
Sulfate ion	Mild and low alloy steels	Uniform, pitting and crevice corrosion	A.1.1.1.4
	Stainless steels	Pitting	A.2.1.1.4
Transition metal ions	Aluminum alloys	Pitting and crevice corrosion	A.6.3
Temperature	Mild and low alloy steels	Uniform, pitting and crevice corrosion	A.1.1.1.3, Figures A.1-7 and A.1-8
		SSC	A.1.1.3.5
	Stainless steels	Pitting and crevice corrosion	A.2.1.1.3, Figure A.2-2
		SCC	A.2.1.2.2, Figure A.2-6
	Titanium alloys	Pitting and crevice corrosion	A.3.1.2.1, Figure A.4-1
Flow velocity	Mild and low alloy steels	General effects	A.1.1
	Stainless steels	General effects	A.2
	Nickel alloys	Applicability in high flow rates	A.4.1

FIGURE 2.1-1. CORROSION RATE OF AISI 1020 STEEL AS A FUNCTION OF pH
IN (1) DEGASSED SALTON SEA FLUID AT 450°F AND (2) DEGASSED
SEA WATER AT 250°F.
Sources: George, Manning, and Schreiber 1975;
Needham et al. 1979

The results of tests of carbon and low alloy steels in simulated geothermal fluid of varying chloride concentration are presented in Figure 2.1-2. The tests were run in autoclaves at 480°F and a total pressure of 100 psig. The pH was adjusted to 4.5 to 4.8 with carbon dioxide (Shannon 1980). The corrosion rate of carbon steels appears to increase about tenfold as chloride concentration is increased from 6000 ppm to 66,000 ppm.

Another major effect of chloride in the geothermal fluid is the breakdown of passivity of passivated alloys. Rapid pitting, crevice corrosion, and stress corrosion cracking of some stainless steels can occur in even dilute chloride solutions if oxygen is present. The chloride threshold for chloride stress corrosion cracking (SCC) of many austenitic stainless steels may be about 5 ppm (Neumann and Griess 1964). Chloride ions are extremely mobile. Due to electrochemical processes, chloride ions can concentrate to near saturation in pits or crevices. For this reason, the chloride concentration of the bulk fluid may be misleading.

Hydrogen Sulfide - Perhaps the most severe effect of hydrogen sulfide is its attack on certain copper and nickel alloys, especially cupronickels and other copper alloys containing nickel, as well as Monels. These metals have performed well in seawater but are practically unusable in geothermal fluids containing hydrogen sulfide. The threshold of attack is less than 30 ppb hydrogen sulfide.

The effect of hydrogen sulfide on iron-based materials is less predictable; accelerated attack occurs in some cases, and inhibition occurs in others. High-strength steels are often subject to sulfide stress cracking (SSC). Hydrogen sulfide may also cause hydrogen blistering of steels. Oxidation of hydrogen sulfide in aerated geothermal process streams increases the acidity of the stream, and this increases corrosiveness. Hydrogen sulfide in the plant atmosphere causes rapid failure of copper or silver electrical contacts.

Carbon Dioxide Species - Dissolved carbon dioxide occurs naturally in many geothermal fluids and has a major corrosive effect on carbon and low alloy steels. Carbon dioxide is one of the most important species in the control of the pH of geothermal fluids. In many cases, the low pH resulting from carbon dioxide dissolved in condensed steam is the factor controlling corrosion of geothermal steam lines. Increasing the partial pressure of carbon dioxide reduces the pH of solutions. For dilute sodium chloride (3500 ppm chloride) solutions, the following relationship has been shown (de Waard and Milliams 1975a):

$$\text{pH} = -0.5 \log P_{\text{CO}_2} + 4.17 \times 10^{-3} T + 2.57$$

FIGURE 2.1-2. EFFECT OF CHLORIDE CONCENTRATION ON UNIFORM CORROSION OF CARBON AND LOW ALLOY STEELS. (480°F, pH 4.5 to 4.8, TOTAL PRESSURE 1000 PSIG, LESS THAN 0.01 ppm DISSOLVED OXYGEN)

Source: Shannon 1980

where: P_{CO_2} = partial pressure of carbon dioxide in bars

T = absolute temperature ($^{\circ}K$)

Carbonic acid (dissolved carbon dioxide) has been shown to provide an alternate reaction pathway for proton reduction. This is a critical and often rate-controlling step in the corrosion of steel in air-free waters (de Waard and Milliams 1975a; 1975b). The reaction is:

The net result is the same as the proton reduction reaction, but the rate is not controlled by the concentration of hydrogen ions. Thus, dissolved carbon dioxide increased the corrosion rate of steel by lowering the pH, increasing hydrogen ion diffusion, and providing an alternative route for proton reduction. De Waard and Milliams (1975a) devised a modified Arrhenius equation which predicts the corrosion rate of grit-blasted steel in dilute (3500 ppm) chloride solution. In logarithmic format, the equation is:

$$\text{Log mpy} = 0.67 \log P_{CO_2} - 5.55 \times 10^{-3} T - \frac{2.32 \times 10^{-3}}{T} \times 11.071$$

where

P_{CO_2} = partial pressure of carbon dioxide in bars

T = absolute temperature ($^{\circ}K$)

This kinetic relationship applies to bare carbon steels exposed to many lower chloride geothermal fluids and to carbon steels wetted by condensate in contact with air-free geothermal steam. The relationship was found to be valid from 32 $^{\circ}F$ to 180 $^{\circ}F$. Above 180 $^{\circ}F$, stable iron carbonate films are formed which slow the corrosion rate as compared to predicted values.

Ammonia Species - Ammonia is known for its ability to cause SCC (season cracking) of many copper alloys (Fontana and Greene 1967; George, Manning, and Schreiber 1975; Staehle 1967). There is some evidence that ammonia may increase the corrosion of carbon steel in air-free sea water (George, Manning, and Schreiber 1975). Significant quantities of ammonia will affect the condensate pH. The equations for determining pH may not be valid when significant quantities of ammonia are present.

Sulfate Ion - Sulfate plays a minor role in most geothermal fluids. In some low-chloride streams, sulfate will be the main aggressive anion. Even in this case, it rarely causes the same severe localized attack as chloride.

Transition Metal Ions - Heavy or transition metal ions might also be included as key species. Their action on most materials at low concentrations is not well known. However, the poor performance of aluminum alloys in geothermal fluids may be due in part to low levels of copper or mercury. Salton Sea geothermal fluids contain many transition metal ions at greater than trace concentrations. Some oxidized forms of transition metal ions (ferric ion, cupric ion, etc) are corrosive, but in geothermal fluids transition element ions are present in the lowest oxidation state (most reduced ionic form). Oxygen can convert ferrous ion to ferric ion, which is another reason to exclude oxygen from geothermal streams.

2.2 Scaling (Solids Deposition)

Scaling or solids deposition is another aspect of geothermal fluids that influences materials performance. Precipitation of species from or onto equipment surfaces can affect corrosion rates. Suspended particles may cause erosion. The composition of the scale and the rate of precipitation depend on fluid composition and specific process stream conditions, which are beyond the scope of this report. Only a brief discussion of silica, calcium carbonate, and calcium sulfate scaling is given.

Silica (SiO_2) - Silica is not a corrosive species but does cause major scaling problems in many high temperature waters. At pH less than 8, the solubility of silica primarily depends on temperature and is not dependent on pH. The silica is present as a monomer (H_4SiO_4). When cooled below the saturation temperature for amorphous silica, the silica monomer precipitates (Ellis and Mahon 1977; Barnes and Rimstidt 1976). Figure 2.2-1 gives the saturation temperature of amorphous silica as a function of silica in solution prior to flashing. If the concentration of silica in the input stream is known, the occurrence of amorphous silica precipitation can be predicted. Using the appropriate flash-corrected curve in Figure 2.2-1, the saturation temperature and the expected final temperature are compared.

For example, if geothermal water containing 700 ppm silica is to be cooled without flashing (no water loss), read down the 700 ppm silica line. The intersection of the 700 ppm line and the "UNFLASHED" line shows that the saturation temperature is approximately 325°F. Below this temperature, silica precipitation will occur. If 20 percent of the fluid containing 700 ppm silica is to be flashed into steam, the intersection of 700 ppm silica on the "20 percent flash" curve indicates a saturation temperature of approximately 365°F. The "20 percent flash" curve is corrected for the water loss from the input (700 ppm) solution. The same

FIGURE 2.2-1. SATURATION TEMPERATURE FOR AMORPHOUS SILICA.
 NOTE: IF THE SATURATION TEMPERATURE FOR THE CONCENTRATION OF SILICA IN THE INPUT FLUID IS SIGNIFICANTLY HIGHER THAN THE FINAL STREAM TEMPERATURE, SCALING BY AMORPHOUS SILICA WILL RESULT. NOT VALID IF INITIAL OR FINAL pH GREATER THAN OR EQUAL TO 8.

Source: Barnes and Rimstidt 1976.

result would be produced by calculating a concentration correction and using the "UNFLASHED" line.

The kinetics of silica polymerization are complex, and the rate depends on both the degree of supersaturation and temperature. The reactions may be chain reactions catalyzed by chloride and hydroxide. Sodium ions, potassium ions, and sulfate ions have little effect (Ellis and Mahon 1977).

Because the kinetics of scale deposition are sluggish at ambient temperatures, the location of the siliceous scale is dependent on residence time of the supersaturated fluid. Studies have shown that acidification slows the rate of precipitation (Ellis and Mahon 1977). Acidification of Salton Sea fluid (pH 5 to 6) to pH 4.5 delays precipitation for at least three months (Austin et al. 1977).

At pH greater than 8, ionization of silica occurs, which greatly increases the solubility of silica. Above pH 8, Figure 2.2-1 is no longer valid. At the East Mesa desalinization facility, the flashed geothermal fluid pH is 9.5 to 9.7. Silica concentrations of 500 to 600 ppm are acceptable from a scaling standpoint (U.S. Bureau of Reclamation 1977).

In most cases geothermal water can be assumed to be in equilibrium with quartz if the reservoir temperature is greater than about 300°F. Comparison of the quartz solubility expression (Ellis and Mahon 1977):

$$\text{Silica (ppm)} = 5.86 \times 10^5 e^{-3531/T}$$

where Silica = equilibrium concentration of silica in water in contact with quartz.

T = absolute temperature (°K)

with the unflashed curve in Figure 2.2-1 indicates that silica scaling should not be a major problem for resources with reservoir temperatures less than approximately 300°F, provided no flashing occurs.

Calcium Carbonate - Most high temperature geothermal waters are close to saturation with calcium carbonate (Ellis and Mahon 1977). For solutions at unit activity:

$$\log K_s = -1.183 \times 10^{-2} t - 8.03$$

where t = temperature (in °C).

K_s = solubility product of calcium carbonate.

The relationship in the formula indicates that calcium carbonate solubility decreases as temperature increases. The solubility is pH dependent and therefore, in geothermal environments, is very sensitive to carbon dioxide partial pressure. Figure 2.2-2 illustrates the effect of carbon dioxide partial pressure and temperature on calcium carbonate solubility in pure water.

This figure shows that as long as carbon dioxide partial pressure is maintained, cooling of a geothermal fluid will not cause calcium carbonate scaling. The loss of dissolved carbon dioxide at any point where flashing occurs often causes serious calcium carbonate scaling. Calcium carbonate plugging of well bores has been observed at Cerro Prieto, East Mesa, and Brady Hot Springs. At East Mesa, scale forms at any point where flashing occurs (e.g., at orifices, valves, or elbows).

Increasing ionic strength reduces the activity of calcium ion and carbonate. Therefore, the solubility of calcium carbonate increases with increasing ionic strength, as shown in Figure 2.2-3.

Calcium Sulfate - The solubility of calcium sulfate in pure water is 2090 ppm at 86°F and 1620 ppm at 212°F (Handbook of Chemistry and Physics 1966). Thus, if the concentration of calcium ion and sulfate ion is high enough in the initial fluid, cooling may cause scale formation. Solubility is not sensitive to pH in the range of geothermal fluids.

FIGURE 2.2-2. SOLUBILITY OF CALCIUM CARBONATE IN PURE WATER AS A FUNCTION OF CARBON DIOXIDE PARTIAL PRESSURE AND WATER TEMPERATURE

Source: Ellis and Mahon 1977

FIGURE 2.2-3. EFFECT OF IONIC STRENGTH AND TEMPERATURE ON SOLUBILITY OF CALCIUM CARBONATE AT CONSTANT CARBON DIOXIDE PARTIAL PRESSURE (180 psia)

Source: Ellis and Mahon 1977

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3.0 EFFECTS OF UTILIZATION MODE ON GEOTHERMAL MATERIALS SELECTION PROBLEMS

The corrosiveness of a geothermal environment is controlled by the temperature, pressure, velocity, concentration of certain key corrosive species in the fluid or steam, the interaction of key species, and the nature of the alloy exposed to the environment.

In Section 2, several corrosive species were identified and their individual effects discussed. In this section, the expected ranges of temperature, pressure, and velocity of geothermal process streams will be defined. The interaction of these chemical and physical factors and their effects on the general corrosiveness of geothermal process streams will be discussed.

This section of the handbook is divided into two parts. Section 3.1 defines nine possible power cycles: one for steam-dominated sources, five for liquid-dominated sources recovered by natural pressure, and three for liquid-dominated sources recovered by pumping. The three pumped-source power cycles are similar to those for sources recovered by natural pressure except for the down-hole pumping equipment and potentially higher temperatures and pressures of the primary geothermal fluid. Appendix C presents a worldwide listing of currently operational and proposed geothermal power plants, while Appendix E discusses geothermal plant availability.

These geothermal power cycles are defined to acquaint materials and corrosion engineering personnel with the environments which may be encountered. The cycles provide data on which corrosion and scaling experiments can be based. The cycles also delineate the range of environmental parameters for which materials data must be collected and catalogued for a geothermal materials data system.

Process flow diagrams, process stream conditions, and major equipment items are presented for each power cycle. General fluid properties that influence the applicability of power cycles to a particular geothermal resource are discussed. Finally, three power cycles are considered in detail. The general corrosiveness of various streams is described in terms of variations in chemistry and temperature.

Section 3.2 discusses the direct utilization of geothermal resources, and resources with temperatures too low for economically feasible power generation are considered. The temperature below which direct utilization is unfeasible is dependent on a number of resource-specific factors. However, it has been suggested that approximately 120°F represents the lower limit for cost effective space-heating using geothermal resources without heat pump augmentation (Culver 1976). This temperature is the lower limit for geothermal resources considered in Section 3.2. Two general systems of direct utilization are considered in Section 3.2: mono-fluid systems and bifluid systems, and several generalizations about

materials problems are presented. The materials problems of lower temperature resources utilized by heat pump augmentation are beyond the scope of this document. Appendix D presents a listing of DOE-sponsored direct utilization projects.

3.1 Geothermal Power Cycles

A thermodynamic power cycle is the process employed to extract and utilize geothermal energy to produce electricity. The methods used in the power cycle to produce steam or other vapor to drive a turbine depend on the characteristics of the geothermal fluid. The four general types of geothermal resources found in the United States are steam-dominated, liquid-dominated, hot dry rocks, and geopressed resources. National interest in electrical generation is focused on the first two types of resources, and it is these resources for which typical power cycles are described.

3.1.1 Description of Nine Power Cycles

Nine generalized power cycles are potentially applicable to steam- and liquid-dominated geothermal resources (DeBerry, Ellis, and Thomas 1978). They are listed and classified in Table 3.1-1 according to whether the source is steam- or liquid-dominated and whether it is recovered by natural pressure or pumping.

TABLE 3.1-1 POTENTIAL GEOTHERMAL POWER CYCLES

<u>Steam-Dominated Sources (SD)</u>	
•	Rankine Cycle (SDR)
<u>Liquid-Dominated, Natural Pressure Sources (LDN)</u>	
•	Single Flash Steam Cycle (LDN-SF)
•	Dual Flash Steam Cycle (LDN-DF)
•	Direct Binary Cycle (LDN-B)
•	Flashed Steam Binary Cycle (LDN-FSB)
•	Two-Phase Expander Cycle (LDN-TPX)
<u>Liquid-Dominated, Pumped Sources (LDP)</u>	
•	Direct Binary Cycle (LDP-B)
•	Flashed Steam Binary Cycle (LDP-FSB)
•	Two-Phase Expander Cycle (LDP-TPX)

The power cycles include three major process steps: recovery of the geothermal fluid from the well, production of steam or other vapor to drive a turbine, and discharge of the spent geothermal fluid. Power cycles differ mainly in the methods used to generate steam or other vapor to drive the turbine. The Rankine Cycle uses steam directly from steam-dominated sources. Single and dual flash cycles employ a change in pressure to

generate steam from a liquid-dominated source. Binary cycles use a second liquid as an intermediate heat transfer medium. In direct binary cycles, heat exchange with the geothermal fluid vaporizes the second liquid to drive the turbine. In flashed steam binary cycles, steam is separated from the geothermal fluid and used to vaporize the second liquid. Two-phase expander cycles use a mixture of both vapor and liquid from the geothermal fluid to drive the turbine.

Power cycles are also classified by the method of geothermal fluid recovery from the well. Liquid-dominated resources can be recovered either by natural pressure or by a downhole pump. Recovery by natural pressure has the advantage that little hardware is required down the borehole, which reduces the cost and complexity of equipment installation and maintenance. Downhole pumping can be used to increase well production and well-head temperature, keep noncondensable gases dissolved, and prevent uncontrolled chemical changes caused by flashing of the well fluid during the recovery process.

Figures 3.1-1 through 3.1-9 are process flow sheets for the nine power cycles listed in Table 3.1-1. These diagrams show the primary flow paths, major equipment items, fluid mass per unit of geothermal fluid introduced into the cycle, bulk fluid temperature and pressure, and the anticipated bulk velocity of the fluid in each stream. The diagrams are paired with equipment lists for each cycle (Tables 3.1-2 through 3.1-10).

Heat balances were calculated using ideal cycles according to the first law of thermodynamics. Steam table (Meyer et al. 1968) values were used for all fluid properties. Heat balances and geothermal fluid concentrations for a specific plant design therefore differ from the range of values given in the flow sheets. The differences are due to the deviation of geothermal fluid thermodynamic data from the pure water thermodynamic data of the steam tables and the thermodynamic irreversibilities associated with each piece of equipment. Other assumptions used in calculating the heat balances are noted on each flow sheet.

An equipment list (Tables 3.1-2 through 3.1-10) has been formulated for each of the nine possible potential power cycles. The major components within each equipment item have been given with the associated bulk temperature and the geothermal resource physical phase (liquid/steam/vapor) in contact with the equipment. Localized geothermal fluid velocities within a piece of equipment may differ significantly from the bulk geothermal fluid velocity indicated on the flow sheets. The localized velocity must be considered in material selection and in design of materials compatibility experiments. Because components of a major piece of equipment will probably be made from different materials, they are listed separately under each equipment item.

The equipment lists are not intended to be exhaustive. However, equipment types and operating conditions which closely correspond to

FIGURE 3.1-1. DIRECT (RANKINE) CYCLE FOR STEAM DOMINATED GEOTHERMAL RESOURCE (SDR)
Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-2. EQUIPMENT LIST FOR DIRECT CYCLE USING STEAM-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq.	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor		✓ ✓ ✓		327-373
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out Preventer		✓ ✓ ✓ ✓		240-368
3	Stm/Wtr Sep.	Press. Vessel Internal Baffles & Mist Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓		340-368
4	Turbine	Casing & Fixed Blades Rotor, Blades & Shrouds Seals Nozzle Block Valves (gate/globe/needle) Relief Valve Gauges (press/temp) Strainers		✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		115-368
5	Main Condenser	Shell Tubes Ferrules & Packing Gaskets Baffles Valves (gate/globe/needle) Gauges (press/temp) Ejector Seals Non-condensing Gas Piping Condensing Spray Jets Internal Piping	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		80-125
6	Inter Condenser	same as 5	✓	✓		80-125
7	After Condenser	same as 5	✓	✓		80-125
8	Condensate Pumps	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓		95-120
9	Cooling Tower	Cold Water Basin Frame Work Splash Bars Splash Plates Downspouts Sprayers Drift Eliminators Fanstack Fanguard ^b Valves (gate/globe/needle) Screens Fan ^b Fan Drive Motor ^b Fan Gear Set ^b Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		80-125
10	Circ Water Pump	same as 8	✓			80-125

^a Refers to equipment numbers in Figure 3.1-1.

^b Forced draft system only

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- FLUID AT TURBINE OUTLET 2 WT% LIQUID
- ECONOMIC OPTIMUM FLASH POINT OCCURS AT EQUAL TEMPERATURE DIFFERENCE
 - A. WELL HEAD AND FLASH TANK
 - B. FLASH TANK AND CONDENSER
 REF. BE-458, PG. 4-4
- STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM NO. 5
- CONSTANT ENTHALPY ACROSS FLASH TANK
- PRESSURE OF 2.5 TO 5.0 IN Hg FOR ALL CONDENSERS
- 10% PRESSURE DROP FROM STREAM NO. 1 TO NO. 2
- COOLING WATER AT 80°F
- MASS RATIO FOR NONCONDENSABLE GAS IS 0.03 LB./LB. OF STREAM NO. 1

◇ STREAM NUMBER
○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1		TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (ft/s)	COMMENT
	7%	20%				
1	1.0	1.0	335 - 500	110 - 881	10 - 75	WELL HEAD
2	1.0	1.0	325 - 498	100 - 671	10 - 75	PLANT BOUNDARY
3	0.18 - 0.28	0.30 - 0.38	225 - 317	17.0 - 85.0	50 - 150	TURBINE INLET CONDITIONS
4	0.12 - 0.08	0.02 - 0.70	225 - 317	17.0 - 85.0	5 - 30	FLUID DISCARD
5	0.12 - 0.02	0.02 - 0.70	225 - 317	40 - 400	3 - 10	FLUID REINJECTION
6	0.03 - 0.18	0.18 - 0.28	100 - 134	2.5 - 5.0 IN Hg	250 - 400	TURBINE OUTLET
7	1.12	0.12	225 - 317	17.0 - 85.0	50 - 150	STEAM TO EJECTORS
8	0.03	0.03	100 - 134	2.5 - 5.0 IN Hg	50 - 150	NONCONDENSABLE GAS
9	2.17 - 3.31	5.5 - 6.8	100 - 134	2.5 - 5.0 IN Hg	3 - 10	CONDENSATE
10	2.5 - 4.9	2.5 - 4.9	100 - 134	2.5 - 5.0 IN Hg	3 - 10	—
11	6.1 - 7.1	8.3 - 11.7	100 - 134	15 - 30	3 - 10	COOLING WATER DISCHARGE
12	5.0 - 8.8	7.8 - 11.4	80	40	3 - 10	COOLING WATER SUPPLY
13	0.03	0.03	118 - 134	12 - 20	30 - 80	VENT GAS

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FIGURE 3.1-2. SINGLE FLASH STEAM CYCLE FOR NATURAL PRESSURE LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDN-SF)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-3. EQUIPMENT LIST FOR SINGLE FLASH STEAM CYCLE USING NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor Pump		✓	✓ ✓ ✓	335-500
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out Preventer			✓ ✓ ✓ ✓	335-500
3	Flash Tank	Press. Vessel Internal Baffles & Mist Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	335-500
4	Steam Scrubber	Press. Vessel Scrubber Elements Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓	335-500
5	Turbine	Casing & Fixed Blades Rotor, Blades, & Shrouds Seals Nozzle Block Valves (gate/globe/needle) Gauges (press/temp) Relief Valve & Silencer Strainers		✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		109-500
6	Condenser (Main)	Shell Tubes Ferrules & Packing Gaskets Baffles Valves (gate/globe/needle) Gauges (press/temp) Ejector Seals Non-condensable Condensing Spray Jets Internal Piping	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓			80-135
7	Condenser (Inter)	same as 6	✓	✓		80-135
8	Condenser (After)	same as 6	✓	✓		80-135
9	Condensate Pump	same as 12	✓			80-135
10	Cooling Tower	Cold Water Basin Splashbars & Splashplates Downspouts Sprayers Drift Eliminators Fanstock & Fanguard ^b Valves (gate/globe/needle) Screens Fan ^b Fandrive Motor & Gear Set ^b Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		80-135
11	Circ Water Pump	same as 12	✓			80-135
12	Reinjection	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓			180-320

^a Refers to equipment numbers in Figure 3.1-2

^b Forced draft system only

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- FLUID AT TURBINE OUTLET 2 WT % LIQUID
- ECONOMIC OPTIMUM FLASH POINT OCCURS AT EQUAL TEMPERATURE DIFFERENCE
 - A. FIRST STAGE SEPARATOR AND SECOND STAGE FLASH
 - B. SECOND STAGE FLASH AND CONDENSING TEMPERATURE - REF. DE-455 PGL 4.4
- STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM NO. 9
- CONSTANT ENTHALPY ACROSS FLASH TANK
- PRESSURE OF 1.5 - 2.5 psia FOR ALL CONDENSERS
- 10 psia PRESSURE DROP FROM STREAM NO. 1 TO STREAM NO. 2
- COOLING WATER AT 80°F
- MASS RATIO FOR NONCONDENSABLE GAS IS 0.03 LB./LB. OF STREAM NO. 1

STREAM NUMBER

EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1		TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (fps)	COMMENT
	7%	20%				
1	1.0	1.0	320 - 400	90 - 247	3 - 10	WELL HEAD
2	1.0	1.0	313 - 396	80 - 237	3 - 10	PLANT BOUNDARY
3	0.27	0.20	312 - 396	80 - 237	50 - 154	FIRST STAGE STEAM
4	0.23	0.80	315 - 396	80 - 237	3 - 10	FIRST STAGE FLUID
5	0.01 - 0.14	0.08 - 0.12	214 - 265	15.5 - 38.5	50 - 154	SECOND STAGE STEAM
6	0.79 - 0.63	0.68 - 0.72	214 - 265	15.5 - 38.5	3 - 10	SECOND STAGE FLUID TO REINJECTION/DISPOSAL
7	0.05 - 0.18	0.18 - 0.20	115 - 134	1.5 - 2.5	250 - 408	TURBINE EXHAUST HOOD
8	1.8 - 3.8	5.8 - 9.1	115 - 134	1.5 - 2.5	3 - 10	MAIN CONDENSER OUTLET
9	0.03	0.03	115 - 134	1.5 - 2.5	30 - 60	NONCONDENSABLE GASES
10	0.12	0.12	213 - 386	80 - 237	50 - 154	STEAM TO EJECTORS
11	5.8 - 7.7	7.0 - 9.35	115 - 134	10 - 40	3 - 10	CONDENSATE AND COOLING WATER
12	5.8 - 7.5	6.7 - 9.1	80	20 - 40	3 - 10	COOLING WATER
13	0.03	0.03	115 - 134	12 - 20	30 - 60	VENT GAS

70-1188-2

FIGURE 3.1-3. DUAL FLASH STEAM CYCLE FOR LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDN-DF)
Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-4. EQUIPMENT FOR DUAL FLASH STEAM CYCLE USING NATURAL PRESSURIZED, LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq.	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor Pump		✓	✓ ✓ ✓	320-400
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out preventer			✓ ✓ ✓ ✓	320-400
3	Flash Tank (1st)	Press. Vessel Internal Baffles & Mist Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓	265-365
4	Steam Scrubber	Press. Vessel Scrubber Elements Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	265-365
5	Flash Tank (2nd)	same as 3		✓	✓	210-310
6	Steam Scrubber	same as 4		✓	✓	210-310
7	Turbine	Casing & Fixed Rotor, Blades, & Shrouds Seals Nozzle Block Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp) Strainers		✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	105-365
8	Reinjection Pump	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓			214-265
9	Condenser (Main)	Shell Tubes Ferrules & Packing Gaskets Baffles Valves (gate/globe/needle) Gauges (press/temp) Ejector Seals Non-condensable Gas Piping Condensing Spray Jets Internal Piping	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		80-135
10	Condenser (Inter)	same as 9	✓	✓		80-135
11	Condenser (After)	same as 9	✓	✓		80-135
12	Circ Water Pump	same as 8	✓			95
13	Condensate Pump	same as 8	✓			80-135
14	Cooling Tower	a Cold Water Basin b Splashbars & Splashplates c Downspouts d Sprayers e Drift Eliminators f Fanstack & Fanguard ^b g Valves (gate/globe/needle) h Screens i Fan ^b j Fan Drive Motor & Gears Set ^b k Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓		80-135

^aRefers to Equipment numbers in Figure 3.1-3

^bForced draft systems only

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- 10 psia PRESSURE DROP FROM STREAM NO. 1 TO STREAM NO. 2
- MASS RATIO FRO NONCONDENSABLE GAS IS 0.0 - 0.05 LB./LB. OF STREAM NO. 1

◇ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1	TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (fps)	COMMENTS
1	1.0	230 - 400	21 - 247	3 - 10	WELL HEAD
2	1.0	198 - 396	10 - 182	3 - 13	PLANT BOUNDARY
3	0.90 - 1.0	90 - 180	10 - 110	3 - 13	REINJECTION FLUID AT PLANT BOUNDARY
4	0.0 - 0.05	90 - 180	15 - 25	30 - 50	NONCONDENSABLE GASES

70-1109-3

FIGURE 3.1-4. DIRECT BINARY CYCLE FOR NATURAL PRESSURE LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDN-B)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-5. EQUIPMENT LIST FOR DIRECT BINARY CYCLE USING NATURAL PRESSURE,
LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No ^a	Description	Component	Liq. Stm/ Vapor	2 Phase	Temp °F
1	Well	Casing		✓	400-230
		Production Pipe		✓	
		Compactor		✓	
		Pump	✓		
2	Wellhead	Valves (gate/globe/ needle)		✓	400-200
		Gauges (press/temp)		✓	
		Tees & Crosses		✓	
		Blow-out Preventer		✓	
3	Brine/Binary Heat Exchanger	Press. Vessel		✓	370-190
		Tubes or Coils		✓	
		Valves (gate/globe/ needle)		✓	
		Relief Valve		✓	
		Silencer		✓	
		Gauges (press/temp)		✓	
		Internal Baffles & Clips	✓	✓	
4	Reinjection Pump	Casing	✓		90-180
		Shaft	✓		
		Impeller	✓		
		Packing	✓		
		Glands, Latern Rings, Bushings	✓		
		Sealing Rings	✓		
		Gauges (press/temp)	✓		
5	Vent Condenser	Press. Vessel		✓	90-160
		Tubes or Coils		✓	
		Valves (gate/globe/ needle)		✓	
		Gauges (press/temp)		✓	

^aRefers to equipment numbers in Figure 3.1-4

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- ECONOMIC OPTIMUM FLASH POINTS OCCUR AT EQUAL TEMPERATURE DIFFERENCE
 - A. FIRST STAGE SEPARATOR AND SECOND STAGE FLASH
 - B. SECOND STAGE FLASH AND BINARY CONDENSER, REF. B7-453, pg. 4-4
- CONDENSING TEMPERATURE IS 115°F
- CONSTANT ENTHALPY ACROSS FLASH TANK
- 10 psia PRESSURE DROP FROM STREAM NO. 1 TO STREAM NO. 2
- MASS RATIO FOR NONCONDENSABLE GAS IS 0.02 LB./LB. OF STREAM NO. 1

STREAM NUMBER

EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1		TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (fps)	COMMENT
	7%	20%				
1	1.0	1.0	230-500	20.9-681	10-75	WELL HEAD
2	1.0	1.0	197-498	10.9-671	10-75	PLANT BOUNDARY
3	0.07	0.20	197-498	10.9-671	50-150	FIRST STAGE STEAM
4	0.93	0.80	197-498	10.9-671	3-10	FIRST STAGE FLUID
5	0.04-0.21	0.03-0.18	156-307	4.3-74.4	50-150	SECOND STAGE STEAM
6	0.72-0.63	0.82-0.77	156-307	4.3-74.4	3-10	SECOND STAGE FLUID
7	0.06-0.25	0.20-0.35	135-287	2.8-54.9	3-10	STEAM CONDENSATE RETURN
8	0.03	0.03	130-250	15-30	30-50	NONCONDENSABLE GAS
9	0.97	0.97	130-250	2.8-55	3-10	REINJECTION FLUID

FD-1108-3

FIGURE 3.1-5. FLASHED STEAM BINARY CYCLE FOR NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDN-FSB)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-6. EQUIPMENT LIST FOR FLASHED STEAM BINARY CYCLE USING NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor Pump		✓	✓ ✓ ✓	230-500
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out Preventer			✓ ✓ ✓ ✓	230-500
3	Flash Tank (1st)	Press. Vessel Internal Baffle & Mist. Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	230-500
4	Steam Scrubber	Press. Vessel Scrubber Elements Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	225-380
5	Flash Tank (2nd)	same as 3		✓	✓	225-380
6	Steam Scrubber	same as 4		✓	✓	160-225
7	Steam/Binary Superheater	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	225-380
8	Steam/Binary Evaporator	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)	✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	160-225
9	Vent Condenser	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Gauges (press/temp)	✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	160-225
10	Reinjection Pump	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓			130-250

^a Refers to equipment numbers in Figure 3.1-5

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- 20 WT % VAPOR AT WELL HEAD
- ISENTROPIC EXPANSION THROUGH NOZZLE AND TURBINE TO 1.7 psia
- 10 psia PRESSURE DROP FROM STREAM NO. 1 TO STREAM NO. 2
- STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM NO. 1
- PRESSURE OF 1.7 psia FOR ALL CONDENSERS
- COOLING WATER AT 86°F
- MASS RATIO FOR NONCONDENSABLE GAS IS .025 LB./LB. OF STREAM NO. 1

◇ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1	TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (ft/min)	COMMENT
1	1.0	302 - 487	60 - 500	10 - 75	WELL HEAD
2	1.0	282 - 485	50 - 400	10 - 75	PLANT BOUNDARY
3	.20	282 - 485	50 - 400	50 - 150	STEAM
4	.30	282 - 485	50 - 400	3 - 10	GEOTHERMAL FLUID
5	AS REQUIRED	—	64 - 485	3 - 10	SCALE PRECIPITATE MODIFICATION AS REQ'D
6	.30	282 - 485	50 - 400	3 - 10	MODIFIED FLUID
7	10.4 - 12.8	80	15 - 30	3 - 10	COOLING WATER SUPPLY
8	3.2 - 3.4	120	20 - 100	3 - 10	MIXED C.W. AND MODIFIED FLUID
9	6.1	282 - 485	50 - 400	50 - 150	EJECTOR STEAM
11	0.025	80 - 120	15 - 30	50 - 150	NONCONDENSABLE GAS
13	7.8 - 10.1	80 - 120	15 - 30	3 - 10	COOLING WATER RETURN

70-11123

FIGURE 3.1-6. TWO-PHASE EXPANDER CYCLE FOR NATURAL PRESSURE LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDN-TPX)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-7. EQUIPMENT LIST FOR TWO-PHASE EXPANDER CYCLE USING NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor Pump	✓		✓ ✓ ✓	302-467
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out Preventer			✓ ✓ ✓ ✓	292-465
3	Steam Separator	Press. Vessel Internal Baffles & Mist Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓	292-465
4	Mixing Chamber	Press. Vessel Mixing Elements Internal Baffles Valves (gate/globe/needle) Gauges (press/temp) Metering Device	✓ ✓ ✓ ✓ ✓ ✓		✓ ✓ ✓ ✓ ✓ ✓	292-465
5	2 Phase Exp Nozzle	Venturi Valves Gauges (press/temp)	✓ ✓ ✓	✓ ✓ ✓	✓ ✓ ✓	292-465
6	Impulse Turbine	Casing & Fixed Blades Rotor, Blades & Shrouds Seals Nozzle Block Valves (gate/globe/needle) Relief Valve Gauges (press/temp) Strainer			✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	Indeter- minate
7	Barometric Condenser	Gaskets Baffles Valves (gate/globe/needle) Gauges (press/temp) Ejector Seals Non-condensable Gas Piping Spray Jets & Piping	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓ ✓ ✓	120
8	Inter Condenser	same as 7	✓	✓	✓	120
9	After Condenser	same as 7	✓	✓	✓	120
10	Condensate Pump	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓			95-120
11	Condensate Pump	same as 10	✓			95-120

^a Refers to equipment numbers in Figure 3.1-6

Source: DeBerry, Ellis, and Thomas 1978

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1	TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (fps)	COMMENTS
1	1.0	212 - 662	20 - 2800	3 - 10	WELL HEAD
2	1.0	212 - 662	20 - 2800	3 - 10	PLANT BOUNDARY
3	1.0	00 - 180	10 - 2800	3 - 10	SPENT FLUID

70-1062-3

FIGURE 3.1-7. DIRECT BINARY CYCLE FOR PUMPED, LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDP-B)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-8. EQUIPMENT LIST FOR DIRECT BINARY CYCLE USING PUMPED,
LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing			✓	212-662
		Production Pipe			✓	
		Compactor			✓	
		Pump	✓			
2	Wellhead	Valves (gate/globe/ needle)	✓	✓	✓	212-662
		Gauges (press/temp)	✓	✓	✓	
		Tees & Crosses	✓	✓	✓	
		Blow-out Preventer	✓	✓	✓	
3	Brine/Binary Heat Exchanger	Press. Vessel	✓		✓	212-662
		Tubes or Coils			✓	
		Valves (gate/globe/ needle)	✓		✓	
		Relief Valve & Silencer	✓	✓		
		Gauges (press/temp)	✓		✓	
4	Reinjection Pump	Casing	✓			80-180
		Shaft	✓			
		Impeller	✓			
		Packing	✓			
		Glands, Lantern Rings, Bushings	✓			
		Sealing Rings	✓			
		Gauges (press/temp)	✓			

^aRefers to equipment numbers in Figure 3.1-7

Source: DeBerry, Ellis, and Thomas 1978

ASSUMPTIONS

- FLUID AT WELL HEAD 20 WT % VAPOR
- ECONOMIC OPTIMUM FLASH POINTS OCCUR AT EQUAL TEMPERATURE DIFFERENCE
 - A. WELL HEAD TEMPERATURE AND SECOND STAGE FLASH
 - B. SECOND STAGE FLASH AND CONDENSER TEMPERATURE, REF. DE-455, PG. 44
- 10 psia PRESSURE DROP FROM STREAM NO. 1 TO STREAM NO. 2
- CONSTANT ENTHALPY ACROSS FLASH TANK
- CONDENSING TEMPERATURE 115°F
- MASS RATIO FOR NONCONDENSABLE GAS IS 0.03 LB./LB. OF STREAM NO. 1

- ◇ STREAM NUMBER
- EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1	TEMPERATURE (°F)	PRESSURE (psia)	VELOCITY (fps)	COMMENT
1	1.0	230 - 662	21 - 2306	3 - 10	WELL HEAD
2	1.0	198 - 661	11 - 2355	3 - 10	PLANT BOUNDARY
3	.20	198 - 661	11 - 2355	50 - 150	FIRST STAGE STEAM
4	.50	198 - 661	11 - 2355	3 - 10	FIRST STAGE FLUID
5	.03 - .18	156 - 306	4.3 - 73	50 - 150	SECOND STAGE STEAM
6	.62 - .77	156 - 306	4.3 - 73	3 - 10	SECOND STAGE FLUID
7	.20 - .38	115 - 328	17.8 - 64	3 - 10	STEAM CONDENSATE
8	.03	120 - 250	15 - 30	50 - 150	NONCONDENSABLE GASES

70-11105-3

FIGURE 3.1-8. FLASHED STEAM BINARY CYCLE FOR PUMPED LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDP-FSB) (DeBerry, Ellis, and Thomas 1978)

TABLE 3.1-9. EQUIPMENT LIST FOR FLASHED STEAM BINARY CYCLE USING PUMPED, LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No. ^a	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing Production Pipe Compactor Pump	✓ ✓ ✓ ✓		✓ ✓ ✓ ✓	230-662
2	Wellhead	Valves (gate/globe/needle) Gauges (press/temp) Tees & Crosses Blow-out Preventer			✓ ✓ ✓ ✓	230-662
3	Flash Tank (1st)	Press. Vessel Internal Baffles & Mist Elim. Valves (gate/globe/needle) Level Control Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓ ✓	230-662
4	Steam Scrubber	Press. Vessel Scrubber Elements Valves (gate/globe/needle) Relief Valves & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	185-401
5	Flash Tank (2nd)	same as 3		✓	✓	185-401
6	Steam Scrubber	same as 4		✓	✓	160-300
7	Steam/Binary Superheater	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)		✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	185-401
8	Steam/Binary Evaporator	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Relief Valve & Silencer Gauges (press/temp)	✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	✓ ✓ ✓ ✓ ✓	140-250
9	Vent Condenser	Press. Vessel Tubes or Coils Valves (gate/globe/needle) Gauges (press/temp)	✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	✓ ✓ ✓ ✓	130-250
10	Reinjection Pump	Casing Shaft Impeller Packing Glands, Lantern Rings, Bushings Sealing Rings Gauges (press/temp)	✓ ✓ ✓ ✓ ✓ ✓ ✓			130-250

^a Refers to equipment numbers in Figure 3.1-8
Source: DeBerry, Ellis, and Thomas 1978

PG-1115-3

FIGURE 3.1-9. TWO-PHASE EXPANDER FOR PUMPED, LIQUID-DOMINATED GEOTHERMAL RESOURCE (LDP-TPX)

Source: DeBerry, Ellis, and Thomas 1978

TABLE 3.1-10. EQUIPMENT LIST FOR TWO-PHASE EXPANDER CYCLE USING PUMPED,
LIQUID-DOMINATED GEOTHERMAL RESOURCE

Equip No.	Description	Component	Liq	Stm/ Vap	2 Phase	Temp °F
1	Well	Casing	✓		✓	302-662
		Production Pipe	✓		✓	
		Compactor	✓		✓	
		Pump	✓			
2	Wellhead	Valves (gate/globe/needle)	✓		✓	302-662
		Gauges (press/temp)	✓		✓	
		Tees & Crosses	✓		✓	
		Blow-out Preventer	✓		✓	
3	Mixing Chamber	Press. Vessel	✓		✓	280-662
		Mixing Elements	✓		✓	
		Internal Baffles	✓		✓	
		Valves (gate/globe/needle)	✓		✓	
		Gauges (press/temp)	✓		✓	
		Metering Device	✓		✓	
4	2Ph Exp Nozzle	Venturi	✓	✓	✓	280-662
		Valves (gate/globe/needle)	✓	✓	✓	
		Gauges (press/temp)	✓	✓	✓	
5	Impulse Turbine	Casing & Fixed Blades			✓	Indeter- minate
		Rotor, Blades, & Shrouds			✓	
		Seals			✓	
		Nozzle Block			✓	
		Valves (gate/globe/needle)			✓	
		Relief Valve			✓	
		Gauges (press/temp)			✓	
		Strainer			✓	
6	Barometric Cond.	Gaskets	✓	✓	✓	>120
		Baffles	✓	✓	✓	
		Valves (gate/globe/needle)	✓	✓	✓	
		Gauges (press/temp)	✓	✓	✓	
		Ejector		✓	✓	
		Seals	✓	✓	✓	
		Non-condensable Gas Piping		✓	✓	
		Spray Jets & Piping	✓			
7	Inter Condenser	Same as 6	✓	✓	✓	>120
8	After Condenser	Same as 6	✓	✓	✓	>120
9	Condensate Pump	Casing	✓			95-120
		Shaft	✓			
		Impeller	✓			
		Packing	✓			
		Glands, Lantern Rings, Bushings	✓			
		Sealing Rings	✓			
		Gauges (press/temp)	✓			

^a Refers to equipment numbers in Figure 3.1-9

Source: DeBerry, Ellis, and Thomas 1978

material selection or material compatibility test programs can be selected from the lists. For example, lube oil and hydrogen cooler environments are similar in service to the conditions found in condensers.

3.1.2 Effect of Geothermal Fluid Properties on Cycle Selection

The selection of a power cycle depends on the characteristics of the fluid. Fluid properties which influence the power cycle selection include (1) total dissolved solids and scaling potential, (2) pressure, (3) temperature, (4) chemical composition, and (5) concentration of non-condensable gases. The influence of these properties is discussed in this section.

Other than corrosiveness, total dissolved solids and scaling potential are perhaps the most important fluid properties to be considered when selecting a system which utilizes geothermal fluid. Although scaling is a complex phenomenon outside the scope of this discussion, scaling will trap the unwary. Minor leakage at valve packing glands and pump seals is expected in most liquid systems. Geothermal fluid with only modest quantities of total dissolved solids may leak at low rates. Over the period of a month, the deposited solids may render valves inoperative and score pump seals such that these items no longer serve their intended purpose. Consequently, the level of total dissolved solids must be combined with an estimate of leak rate to determine the volume of solids deposited. From the estimated volume of solids deposited, an estimate of system performance, maintenance requirements, etc., can be combined with the end product requirements to select the applicable energy system.

Chemical composition of the geothermal fluid must be considered from the aspect of materials required to survive the intended environment (Section 3.1.3 considers this aspect in more detail). System selection criteria must contain an estimate of material availability and the form of the material required to survive the intended environment. An aggressive chemical environment created by the geothermal fluid may dictate the type of system which will be acceptable.

The noncondensable gas concentration in the geothermal fluid must be considered when selecting heat transfer equipment, net positive suction head of pumps, and downstream volume required after pressure release devices. Each of these items significantly affects the availability of components which in turn affects the type of system selected for a given application.

Thus, the physical properties of the geothermal fluid may well limit the types of systems which can be effectively used. System selection should consider the effect of the geothermal fluid properties.

3.1.3 Effect of Fluid Properties on Materials Performance In Specific Process Streams

The corrosive nature of geothermal fluids depends mainly on the chemical composition, temperature, and localized fluid velocity. This section describes how the temperature, localized velocity, and chemical composition of the wellhead fluid are altered during the energy extraction process. Defining variations in the corrosive nature of the geothermal fluid in the specific process streams provides a useful framework for selecting construction materials and preventing materials problems.

Most of the geothermal resources used in electric power generation reviewed for this handbook have certain common characteristics. Most are liquid-dominated and have total key species (chloride + bicarbonate + carbonate + sulfate + hydrogen sulfide + ammonia) equal to or less than 16,000 ppm. At least 45 percent of the total key species is chloride ion. The properties of these resources can be summarized by the following limits.

- Total Key Species are less than 16,000 ppm but greater than 500 ppm.
- Chloride constitutes at least 45 percent of the Total Key Species.
- Noncondensable gas is less than 4 percent in the reservoir fluid. Most of the gas is carbon dioxide.
- Hydrogen sulfide and ammonia are present in low ppm amounts.
- The pH of unflashed fluid is between 5 and 7.
- The geothermal fluid as produced contains no oxygen.
- At each designed phase separation, a separation efficiency of 99.5 percent or better is assumed.

The following sections identify potential material problems in specific process streams in three power cycles for natural pressure, liquid-dominated resources. Dual flashed steam, direct binary, and flashed steam binary cycles are considered. These cycles were selected because they produce stream conditions that are representative of other cycles. The discussions refer to stream numbers on the flow diagrams in Section 3.1.1. Unless stated otherwise, it is assumed that the reservoir fluid chemistry is within the range described above.

3.1.3.1 Dual Flash Steam Cycle

This cycle is illustrated in Figure 3.1-3.

Stream 1: Wellhead Fluid

This is the highest temperature fluid in the process. The temperature is 320° to 400°F. The aqueous pH of this two-phase stream is between 5 and 6 due to the presence of dissolved carbon dioxide and hydrogen sulfide. In general, uniform corrosion will be controlled mostly by pH and temperature, while the effect of chloride will be minor. Localized corrosion (pitting and crevice corrosion) will be controlled more by chloride concentration and temperature. The nominal bulk velocity of this stream is 3 to 10 ft/sec, and this should cause no materials problems. However, very high (greater than 600 ft/sec), localized velocities may result from localized flashing of the liquid phase. Rapid erosion or droplet impingement failure of pipe elbows and valve gates may occur.

Introduction of oxygen will greatly increase corrosiveness in this environment. Steps must be taken to prevent severe corrosion by oxygen during plant outages.

Well casings and other low alloy steels are also susceptible to sulfide stress cracking, especially during shut-down. Yield strength should be less than 100 ksi (thousand pound/in²) or Rockwell Hardness C less than or equal to 22. Grades containing less than one percent nickel should be specified for use.

Stream 2: Fluid from Pretreatment to First Stage Separator

The change in corrosiveness of this stream depends on pretreatment method. Acidification to reduce scaling can increase the corrosion rate by a factor of three or four per pH unit below pH of about 5. Removal of hydrogen sulfide would have little effect on uniform corrosion of carbon steel, but would eliminate sulfide stress cracking constraints on yield strength of low alloy steels.

Streams 3 and 10: First Stage Steam to Turbine and Gas Ejectors

This 313° to 396°F steam is assumed to contain 0.5 percent or less droplet carryover from the first stage separator. About 98 percent of the entrained chloride will be scrubbed into condensate in the first several hundred feet and can be removed by condensate traps.

This steam will contain most of the carbon dioxide, hydrogen sulfide, and much of the ammonia from the reservoir fluid. Carbon dioxide is the species which has the most pronounced effect on corrosion of carbon

steel in this phase. Increasing temperature and carbon dioxide partial pressure increases the corrosion rate of carbon steel wetted by condensate films. Hydrogen sulfide has little effect on corrosion of carbon steel, but exfoliation of iron sulfide scale can damage the turbine. Sulfide stress cracking of high strength, low alloy steels will not occur unless a moisture film is present.

The in-leakage of oxygen into these streams can cause tenfold corrosion increases for carbon steel. The normal pressure of these lines (80 to 237 psia) makes oxygen in-leakage during normal operation unlikely. Suitable shut-down procedures are required.

Stream 4: First Stage Flash Liquid to Second Stage Flash Tank

This liquid stream loses a large fraction of its dissolved carbon dioxide and hydrogen sulfide in flashing. The pH probably increases by at least one pH unit. This pH increase should more than offset the increase in chloride concentration, and this stream should be less aggressive to carbon steel than Stream 2. Localized flashing and erosion by resultant high velocity droplets are still factors in this stream, and oxygen in-leakage will cause serious corrosion.

Stream 5: Second Flash Steam

This stream contains significantly less carbon dioxide than Stream 3 or 10. It may contain more ammonia. The pH of condensate films should be higher; and this, coupled with lower temperatures (214° to 265°F), should result in lower corrosion rates compared to first flash steam.

Because this steam may be close to atmospheric pressure, oxygen in-leakage is a much greater threat than for first flash steam. At steam pressures of three psig, oxygen in-leakage around valve stems, due to the venturi effect, has been observed.

Stream 6: Second Flash Liquid to Disposal

This stream has undergone changes similar to those described for Stream 4, though the absolute changes in carbon dioxide, hydrogen sulfide, and pH may be less than for the first flashed liquid. The temperature drop is 100° to 130°F, and this should offset the effect of increasing chloride concentration. This stream should be less aggressive to carbon steel than previous liquid streams. Oxygen in-leakage is an increasing hazard because the pressure of this stream is approaching atmospheric. At this stage the water is still hot enough to cause chloride stress corrosion cracking (SCC) of susceptible materials (such as austenitic stainless steels) in the presence of small amounts of oxygen. This means that the use of pumps with austenitic stainless steel components should be carefully evaluated.

The post-treatment process (most likely for prevention of injection well plugging) is presently poorly defined. If significant cooling occurs in this process, sulfide stress cracking or hydrogen blistering of downstream components (such as the reinjection well piping) could occur. This form of attack is more prevalent at lower temperatures in aqueous solutions and does not necessarily require high sulfide concentrations.

Stream 7: Turbine Exhaust to Condensers

This liquid stream should contain only a few parts per million chloride ion, but may contain considerable amounts of carbon dioxide, hydrogen sulfide, and ammonia. The stream should contain no oxygen, but the very low pressure (3 to 5 inches of mercury) means that air in-leakage may be a problem.

Streams 8, 10, and 12: Cooling Water Systems

In all presently operating geothermal power plants, the most serious materials problems occur in cooling water systems. Cooling tower aeration causes these problems by introducing oxygen into the stream, thus causing oxidation of sulfide to sulfate. This makes the cooling water acidic. Possible solutions include:

- increase the pH of the circulating stream,
- add corrosion inhibitors, and
- use nonmetallic materials or corrosion-resistant alloys.

The use of resistant materials for critical areas (e.g., hydrogen and oil coolers, instrumentation) is advisable.

3.1.3.2 Direct Binary Cycle

The binary cycle is attractive for resources with wellhead temperatures down to 280°F. Such resources do not produce enough steam to make Flashed Steam Cycles economical. This cycle may also be attractive for higher temperature resources since the enthalpy of the separated water is not wasted. Additionally, the turbine is not exposed to geothermal contaminants. Because noncondensable gases can be vented at atmospheric (or greater) pressure, they do not have to be pumped out of the turbine. This is very important if the noncondensable gas concentration is high. Process streams for this cycle are illustrated in Figure 3.1-4.

Stream 1: Wellhead Fluid

This stream is similar to Stream 1 of the Dual Flash Steam Cycle. However, for Direct Binary Cycle applications, the wells are managed to produce the highest temperature and lowest steam fraction. The wellhead fluid may be either single phase (liquid) or two-phase at the anticipated wellhead temperatures of 280° to 400°F. Localized flashing may cause rapid erosion or impingement failure of valves or elbows. Care must be exercised to prevent oxygen in-leakage.

Stream 2: Wellhead to Binary Heat Exchanger

Corrosiveness of this stream is dependent on the method of pre-treatment. The pH of the fluid entering this stream will probably be between 5 and 7. Although acidification to pH 5 should have little effect on corrosion of carbon steel, acidification below pH 5 to retard silica scaling may cause a threefold to fourfold corrosion increase per pH unit. Oxygen intrusion must be avoided.

Surface Contact Binary Heat Exchanger

The most critical geothermal component of the binary cycle is the heat exchanger. Geothermal fluid, either liquid or two-phase, enters the heat exchanger at 198° to 396°F and leaves at around 90°F.

Materials selection for this component is critical because a small leak can result in substantial contamination or loss of working fluid. At the operating inlet temperature, trace oxygen contamination of the inlet fluid could cause rapid stress corrosion cracking of many alloys.

Because of the heat exchanger's extreme temperature drop, silica scaling may be a major problem for this portion of the cycle. If carbon dioxide is not evolved, calcium carbonate scale should not be a problem. The heat exchanger materials must be able to withstand whatever cleaning and descaling techniques are used.

Direct Contact Binary Heat Exchanger (DCHX) and Secondary Fluid Stream

Fewer materials selection problems occur for direct contact heat exchangers (DCHX) than for the surface contact systems. DCHX's do not require corrosion-resistant, thin-walled heat transfer surfaces. The geothermal fluid enters the DCHX at 200° to 400°F and moves countercurrent to the secondary working fluid. The geothermal fluid is in direct contact with the working fluid, which may be isobutane, isopentane, or a mixture of the two hydrocarbons.

Water vapor and water droplet carry-over (containing chlorides and other corrosive species) from a DCHX present materials selection constraints. Tests on a demister-equipped DCHX at East Mesa, CA, showed approximately three percent (by weight) water vapor and one to three percent (by weight) water droplet carry-over in the vapor stream leaving the DCHX (Urbanek 1979). Most of the water vapor condenses before or during movement of the hydrocarbon vapor stream through the turbine. The aqueous condensate may occur as droplets, films, or pools and may contain corrosive ionic species and dissolved non-condensable gases from the geothermal fluid. No method or basis for estimating the corrosiveness of this aqueous phase was found in the literature.

In areas which are alternately wet and dry, such as the binary turbine, dissolved salts in the aqueous films may be highly concentrated. These salts can be highly corrosive. An examination of turbine components from two direct contact binary systems showed deposits of geothermal fluid solutes (Ellis 1980; McAlpin 1980).

Improved demister design may reduce the aqueous droplet carry-over. The amount of water vapor in the secondary hydrocarbon stream of a DCHX depends on the working fluid used and the operating conditions. The amount of water vapor is probably independent of the design of the DCHX.

Stream 3: Binary Heat Exchanger to Reinjection or Discharge

Stream 3 in this cycle is spent fluid from the binary heat exchanger. Chemical changes occurring in the geothermal/binary heat exchanger are more difficult to predict than in the case of flashed steam. Since less flashing occurs, the concentrations of carbon dioxide and hydrogen sulfide will not be decreased as much, and the pH increase due to carbon dioxide and hydrogen sulfide release will be less than in the case of flashed steam. Temperature effects on aqueous equilibria and gas solubility will be more important and may tend to make the cooler fluid more acidic.

Unless pH is lower than 5, the reduced temperature of this stream (about 90° to 130°F) will more than compensate for the increased carbon dioxide (compared to Dual Flash Steam Cycle, Stream 6). The low temperature and pH, and higher carbon dioxide and hydrogen sulfide concentration could cause sulfide stress cracking (SSC) of high strength low alloy (HSLA) steels. Hydrogen blistering is also possible. Nonmetallic materials may be useful for some applications in this environment.

At some sites, it may be necessary to use part of Stream 3 for cooling water. Usefulness will depend on control of the scaling tendencies of the fluid after concentration and possibly on cooling tower hydrogen sulfide emissions. Although probably lower in hydrogen sulfide and carbon dioxide than the flashed steam condensate, this stream contains far more

chloride. Cooling tower aeration will make the water far more aggressive than cooling water derived from condensate. Stress corrosion cracking would be an extreme hazard.

3.1.3.3 Flashed Steam Binary Cycle

This power cycle uses steam flashed from geothermal fluid to vaporize a secondary working fluid, probably a hydrocarbon or fluorocarbon. Use of steam, rather than geothermal fluid, circumvents the scaling problems which may occur in a direct binary system. Like the Direct Binary Cycle, the turbine is isolated from the geothermal environment. Since noncondensable gases can be ejected from the geothermal/binary heat exchanger at greater than atmospheric pressure, pumps are not required for gas removal. This is important for resources with noncondensable gases in excess of a few weight percent, where pumping to maintain turbine outlet vacuum, as in a Dual Flash Steam Cycle, would be uneconomical.

This cycle is being developed for use at the Salton Sea ($>10^5$ ppm Total Key Species). This discussion, however, will consider the typical geothermal resource.

Streams 1 and 2: Wellhead and Wellhead to First Stage Steam Separator

These streams are similar to Streams 1 and 2 of the Dual Flash Steam Cycle. Similar corrosion hazards can be expected.

Streams 3 and 5: First and Second Flash Steam

It is assumed that steam separation efficiency is 99.5 percent. The first stage will contain more noncondensable gas than the second stage steam and will be at higher temperatures.

The corrosive properties of these streams will be similar to the corrosiveness of Streams 3 and 5 of the Dual Flash Steam Cycle. Careful selection of corrosion-resistant materials for the geothermal steam/binary fluid heat exchangers is required. It must also retain good heat transfer characteristics (i.e., it must resist fouling by corrosion products). Assuming the efficient (>99.5 percent) separation of steam, scaling should be a minor problem in these heat exchangers.

Streams 4 and 6: Fluid from First and Second Flash Separators

These streams are analogous to streams of the same number in the Dual Flash Steam Cycle. Similar corrosion problems are to be expected.

Stream 7: Steam Condensate

Assuming efficient steam separation and scrubbing, this stream should contain only low concentrations of chloride ion. It may contain appreciable carbon dioxide as well as hydrogen sulfide and ammonia and may be at subatmospheric pressure. In corrosiveness, this stream is probably similar to Stream 7 of the Dual Flash Steam Cycle. Oxygen must be excluded from the system.

Cooling Water System

The cooling water system will probably use some of the condensate from Stream 7 as make-up water. Problems of the same sort as occur in cooling water for Dual Flash Steam Plants can be expected.

3.2 Direct Utilization Systems

The direct use of geothermal energy can be as varied as the temperature and corrosiveness of the geothermal fluid permits. The end use of the heat will depend on the temperature of the resource under consideration. On the one extreme, process temperatures over 500°F could be obtained at some sites. Such sites could yield high temperature liquid and/or steam for process use. Resources with temperatures as low as about 120°F may be economical for space heating; still lower temperature resources may be used for aquaculture. Because of the extreme range of geothermal conditions and the almost infinite variety of processes possible, detailed cycle diagrams similar to the thermodynamic power cycles presented in Section 3.1 are too numerous to present. However, two basic modes for direct utilization are identified and discussed in the following section.

3.2.1 Basic Use Modes for Direct Utilization of Geothermal Heat

Direct utilization systems can be divided into two basic classes on the basis of the method of handling the geothermal fluid. The choice of use mode is usually dictated by the corrosiveness of the geothermal fluid. The two basic modes are monofluid systems and bifluid systems.

In monofluid systems, geothermal fluid (liquid or steam) is circulated to all parts of the process where geothermal heat is utilized. The monofluid and bifluid systems are contrasted in Figures 3.2-1 and 3.2-2. A partial equipment list is presented in Table 3.2-1.

Bifluid systems (Figure 3.2-2) use an intermediate isolation heat exchanger to transfer the heat from the geothermal fluid to a second working fluid, usually treated water. The secondary fluid then transports the heat to the process. Bifluid systems are normally used when the corrosive or scaling properties of the geothermal water make it desirable to minimize the number and kind of components contacting the geothermal water.

KEY

STREAM NUMBER	DESCRIPTION
1	WELLHEAD
2	GEOTHERMAL SUPPLY
3	DISPOSAL

70-1824-2

TABLE 3.2-1. MONOFLUID DIRECT UTILIZATION SYSTEM

KEY

STREAM NUMBER	DESCRIPTION
1	WELLHEAD
2	GEOTHERMAL FLUID
3	DISPOSAL
4	NON-GEOTHERMAL FLUID

70-1824-2

TABLE 3.2-2. BIFLUID DIRECT UTILIZATION SYSTEM

TABLE 3.2-1. EQUIPMENT LIST FOR DIRECT UTILIZATION SYSTEMS USING LOWER TEMPERATURE RESOURCES

DESCRIPTION	COMPONENT	LIQUID PHASE
Well	Casing	✓
	Production pipe	✓
	Compactor	✓
	Pump	✓
Wellhead	Valves (gate/globe/needle/ball/butterfly)	✓
	Gauges (Temp/press)	✓
	Tees and crosses	✓
Isolation Heat Exchanger (Bifluid system only)	Valves (gate/globe/needle/ball/butterfly)	✓
	Gauges (Temp/press)	✓
	Tees and crosses	✓
	Tubes, Tubesheet, and shell; or Flat Plates	✓

The isolating heat exchanger is often located near the wellhead. Two examples of bifluid systems are (1) space heating using a downhole heat exchanger and water as a secondary fluid, and (2) systems using a conventional heat exchanger and water or an antifreeze solution as a secondary fluid.

3.2.2 Effect of Geothermal Fluid Properties on Use Mode Selection

Use mode selection should always depend on the geothermal fluid properties. The selection of a use mode depends on the characteristics of the fluid. Fluid properties which influence the system selection include (1) corrosiveness, (2) scaling potential, (3) pressure and temperature, and (4) concentration of noncondensable gases. The availability of components made from suitable materials is also a factor. After corrosiveness, scaling potential is perhaps the single most important fluid property to be considered when selecting a use mode for geothermal fluid. In most liquid-carrying systems, minor leakage at valve packing glands and pump seals is expected. Even in systems handling geothermal fluid containing small amounts of total dissolved solids, deposits can build up on valve stems and

pump seals. Within one month the deposits may affect valves and pump seals and make them inoperative. It is often best to minimize the number of valves and pumps contacting geothermal fluid (by use of a bifluid system) in order to reduce maintenance.

Chemical composition of the geothermal fluid must be considered in materials selection. Selection criteria must include material availability and the form of the material required to function in the intended environment. An aggressive chemical environment will affect the type of use mode selected.

The materials problems associated with the process side of a process heat transfer device must not be ignored. In some cases the process stream may be extremely corrosive to many of the materials which would resist the geothermal environment. In other cases, process stream requirements may dictate materials which are not acceptable for geothermal service. In such cases a bifluid system may be required, even if handling the geothermal fluid does not pose significant problems.

Each of the above factors significantly affects the selection of components and affects the type of use mode selected for direct application.

3.2.3 Effects of Fluid Properties in Higher Temperature Resources

Geothermal resources hot enough for use in electric power generation may also be used in direct applications. Direct utilization has been practiced at Brady Hot Springs, Nevada and in New Zealand.

Systems using higher temperature resources are similar to the Direct Binary or Dual Flashed Stream power cycles discussed in Section 3.1. However, in direct utilization, the turbine and condensers are replaced by geothermally-heated process equipment. Materials problems in high temperature direct applications are similar to those for power systems discussed in Section 3.1.

3.2.4 Effects of Fluid Properties in Low Temperature Resources

Low temperature geothermal resources may be economically attractive for space heating, domestic water heating, or supplying process heat. A geothermal fluid's corrosiveness is determined by its chemical components and its temperature and velocity at various points within the direct utilization system.

Most lower temperature resources discussed in Section 4 have fluid properties in the following range.

" Total Key Species (TKS)^a is less than 5000 ppm.

- Chloride fraction of TKS is 3 to 72 percent but greater than 10 ppm.
- The pH of produced fluid is 6.5 to 10.
- Total sulfide concentration is 0.01 to 5 ppm.
- Dissolved oxygen is less than 0.001 ppm, unless stream is aerated.
- Temperature ranges from approximately 120° to 220°F.

Choice of use mode for lower temperature geothermal resources is influenced by factors other than fluid characteristics. Because using custom-fabricated components is not economical in most cases, system must be designed to use standard, readily available components. Additionally, systems such as those used for home heating must be relatively easily maintained by unskilled, part-time operators.

3.2.4.1 Monofluid Direct Utilization System

A typical monofluid system is illustrated in Figure 3.2-1, and the stream numbers in the subheadings below refer to the stream numbers in that figure. At this time, the geothermal fluid pretreatment and post-treatment, if required, are undefined.

Stream 1: Wellhead

In most cases, this stream will be free of oxygen unless it is introduced at the wellhead. Corrosiveness will be largely determined by the concentrations of carbon dioxide, pH, chloride, and hydrogen sulfide.

The corrosion rate of carbon steel will probably be only a few mils per year (mpy). The presence of even ppb levels of hydrogen sulfide in the wellhead fluid can cause sulfide stress cracking (SSC) of high strength steels. This risk can be reduced by using steels with hardness less than Rc 22 (or yield strength less than 100 ksi). Grades of steel containing less than one percent nickel are recommended (an alternative is the use of fiber-reinforced plastic (FRP) casing). Silica scaling will rarely be a problem in lower temperature resources. If carbon dioxide is evolved, scaling by calcium carbonate may occur.

^a Sum of chloride (Cl^-) + sulfate (SO_4^{-2}) + bicarbonate (HCO_3^-) + carbonate (CO_3^{-2}) + hydrogen sulfide (H_2S) + ammonia (NH_3).

Stream 2: Wellhead to Process Equipment

Introduction of oxygen will greatly increase the corrosiveness of the geothermal stream. Aeration will cause steel corrosion rates of tens of mils per year. Because oxygen is very difficult to eliminate, this stream is probably more corrosive than Stream 1. The increased corrosiveness can be prevented by the continuous addition of an oxygen scavenger. This requires special equipment and will probably not be economical in most cases.

Process Equipment

Process equipment will probably consist of some type of heat transfer device. Suitable materials selection may be complicated by the fact that the process stream may require materials not compatible with the geothermal fluid. Commercially-available process equipment sometimes may not be available in suitable alloys. This is true for fan-coils in space heating systems. This equipment is available in the U.S. with either copper or cupronickel tubes, and no other alloys are standard. Virtually all geothermal fluids contain enough hydrogen sulfide to cause rapid failure of most copper or copper-nickel alloys.

The solution to this problem in Iceland is the use of all steel or cast iron components. This requires continuous pretreatment of the geothermal fluid with an oxygen scavenger.

Stream 3: Disposal

This stream may be less corrosive than Stream 2 because the temperature is lower. However, if the stream becomes more aerated, corrosiveness is increased.

3.2.4.2 Bifluid Direct Utilization System

This system is illustrated in Figure 3.2-2. The stream numbers in the subheadings below refer to stream numbers in the figure. As in the case of the monofluid system, the nature of the geothermal fluid [pre- and post-treatment (if such are required)], is currently unknown.

Stream 1: Wellhead Fluid

The corrosiveness of this stream is identical to that of Stream 1 of the monofluid system.

Stream 2: Wellhead to Isolation Heat Exchanger

As in the monofluid system, the corrosiveness of this stream will increase rapidly if oxygen is introduced. However, since the number of

leak-prone components, such as valves and pumps, is probably less than in the monofluid system, the hazard is reduced. Since the isolation heat exchanger can be placed near the wellhead, the amount of piping is reduced.

Isolation Heat Exchanger

The secondary fluid will be noncorrosive; suitable materials selection will have to consider only the corrosiveness of the geothermal fluid. Flat-plate heat exchangers are readily available in a number of materials which will probably be suitable for this service. Tube-and-shell heat exchangers of some suitable materials may also be available. In general, a flat-plate heat exchanger costs less than a tube-and-shell unit of the same heat transfer capacity, and the flat plate design is much easier to clean.

Stream 3: Disposal

The corrosive property of this stream should be comparable to Stream 3 of the monofluid system.

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4.0 SITE-SPECIFIC METALLIC MATERIALS TESTING AND OPERATING EXPERIENCE

This section presents results of metals performance tests and/or metals operating experience from 46 geothermal sites around the world. The sites are arranged alphabetically by country and may be located using the quick reference guide (tabs). Each site is discussed in a separate section with the following exceptions: Lower Temperature Areas of Iceland (Iceland-LTA), including fifteen sites; Higher Temperature Areas of Iceland (Iceland-HTA), including four sites; the Boraciferous Region of Italy (Italy-Boraciferous Region), containing ten sites; and the Madison Aquifer of South Dakota (United States-Madison Aquifer, SD), containing three sites.

Seawater desalination experience may be somewhat relevant to some geothermal applications. The desalination experience is presented in Appendix B. Non-metals performance in geothermal applications is discussed in Section 5.

The geothermal resources in this handbook have been divided into six Geothermal Resource Corrosion Classes. This division will allow the design or corrosion engineer to quickly identify those sites most likely to contain information applicable to his resource. Following the corrosion classification, the organization of the site-specific sections and data presentation format are discussed. This discussion indicates where data are located in each site-specific section and also helps in interpreting that data.

Corrosion Classification of Geothermal Resources

The 36 liquid-dominated resources discussed in this volume can be divided into five classes on the basis of (1) Total Key Species (TKS) (sum in ppm of chloride, sulfate, bicarbonate, carbonate, ammonia, and hydrogen sulfide) in produced fluid; (2) plant boundary temperature (based on existing and planned plants and existing test facilities), and (3) the corrosion behavior of carbon steel. A sixth class includes vapor-dominated resources. These six Geothermal Resource Corrosion Classes are presented in Tables 4.0-1 through 4.0-6.

This geothermal resource corrosion classification serves two purposes. It shows that most of the resources that are hot enough for economical power production and most of the lower temperature resources are rather similar in both their fluid chemistry and their corrosiveness to carbon steel. Second, it allows the design or corrosion engineer to rapidly identify those sites which are most similar to his candidate site. It is expected that similar sites will supply the most relevant information.

TABLE 4.0-1. GEOTHERMAL RESOURCE CORROSION CLASS I

<u>Defining parameters:</u>	
Resource type	Liquid-dominated
Total key species (TKS)*	Greater than 100,000 ppm
Chloride fraction in TKS	99 percent
pH (unflashed fluid)	5 to 6
pH (flashed fluid)	Greater than 6
Vol. gas in steam	Less than 2.5%
Plant inlet temperature	Greater than 390°F
<u>Sites Reviewed in Section 4:</u>	
USA - Salton Sea, CA	
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> In nonaerated, separated fluid, the uniform rate exceeds 50 mpy at 390°F but may decrease to about 15 mpy at 300°F. Serious localized corrosion. In separated nonaerated steam, the corrosion rate is 10 to 50 mpy with serious pitting. Scrubbing steam does not reduce corrosion rate. 	
<u>General Performance of Other Alloys:</u>	
<ul style="list-style-type: none"> T316 stainless steel susceptible to pitting, crevice corrosion, and stress corrosion cracking. 	

* Total chloride + sulfate + carbon dioxide species + sulfide species + ammonia species.

TABLE 4.0-2. GEOTHERMAL RESOURCE CORROSION CLASS II

<u>Defining parameters:</u>	
Resource type	Liquid-dominated
Total key species (TKS)*	1000 to 10,000 ppm
Chloride fraction in TKS	Not established
pH (unflashed fluid)	Much less than 4.5
pH (flashed fluid)	Less than 4.5
Vol. gas in steam	Not established
Plant inlet temperature	250 to 350°F
<u>Sites Reviewed in Section 4:</u>	
Japan - Matsukawa	
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> On basis of pH, the corrosion rate in nonaerated separated fluid should exceed 50 mpy. No actual data available. Corrosion rate in separated nonaerated steam is 20 to 25 mpy with crevice corrosion. 	

* Total chloride + sulfate + carbon dioxide species + sulfide species + ammonia species.

TABLE 4.0-3: GEOTHERMAL RESOURCE CORROSION CLASS III

<u>Defining parameters:</u>	
Resource type	Liquid-dominated
Total key species (TKS)*	10,000 to 20,000 ppm
Chloride fraction in TKS	45 to 99 percent
pH (unflashed fluid)	5 to 6
pH (flashed fluid)	Greater than 6
Vol. gas in steam	Not established
Plant inlet temperature	300 to 375°F
<u>Sites Reviewed in Section 4:</u>	
Mexico - Cerro Prieto	
USA - East Mesa (6-1), CA	
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> • In nonaerated separated fluid, the uniform corrosion rate is typically 5-10 mpy at temperatures of 300 to 375°F. Some localized attack occurs. • Corrosion rates in separated nonaerated steam are typically less than 5 mpy. • Aerated steam condensate is very corrosive. 	
<u>General Performance of Other Alloys:</u>	
<ul style="list-style-type: none"> • Type 316 stainless steel is susceptible to pitting and stress corrosion cracking in liquid streams. • High strength, low alloy steels are susceptible to sulfide stress cracking. • Monel 400 and cupronickels are unsatisfactory. 	

* Total chloride + sulfate + carbon dioxide species + sulfide species + ammonia species.

TABLE 4.0-4. GEOTHERMAL RESOURCE CORROSION CLASS IV

<u>Defining parameters:</u>	
Resource type	Liquid-dominated
Total key species (TKS)*	500 to 10,000 ppm
Chloride fraction in TKS	45 to 99 Percent
pH (unflashed fluid)	Greater than or equal to 5
pH (flashed fluid)	Greater than 7
Vol. gas in steam	Less than 2.5
Plant inlet temperature	250 to 390°F
<u>Sites Reviewed in Section 4:</u>	
El Salvador - Ahuachapan	New Zealand - Wairakei
Iceland - HTA (four sites)	USA - Baca, NM
Japan - Hatchobaru	USA - Brady, H.S., NV
Japan - Otake	USA - Heber, CA
New Zealand - Broadlands	USA - Raft River, ID
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> • In nonaerated fluid at 250 to 390°F, uniform corrosion rates are typically less than 5 mpy with minor pitting. • In nonaerated steam, corrosion rates are typically less than 5 mpy. • High strength low alloy steels are susceptible to sulfide stress cracking. • Aerated steam condensate is very corrosive. 	
<u>General Performance of Other Alloys:</u>	
<ul style="list-style-type: none"> • Type 316 stainless steel is susceptible to stress corrosion cracking in aerated fluid. • Corrosion-fatigue of 12 Cr turbine blades by geothermal steam is twice as severe as corrosion-fatigue by boiler quality steam. 	

* Total chloride + sulfate + carbon dioxide species + sulfide species + ammonia

TABLE 4.0-5. GEOTHERMAL RESOURCE CORROSION CLASS V

<u>Defining parameters:</u>	
Resource type	Liquid-dominated
Total key species (TKS)*	Less than 5000 ppm
Chloride fraction in TKS	3 to 72 percent
pH (unflashed fluid)	Greater than 6.5
pH (flashed fluid)	Not applicable
Vol. gas in steam	Not applicable
Plant inlet temperature	120 to 220°F
<u>Sites Reviewed in Section 4:</u>	
Iceland - LTA (15 sites)	
USA - Klamath Falls, OR	
USA - Madison Aquifer, SD (three sites)	
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> • In nonaerated fluid with pH greater than 9, uniform corrosion rates are typically less than 1 mpy. • In nonaerated fluid with pH 6 to 9, uniform corrosion rates of 1 to 5 mpy are typical. • Pitting of 0 to 30 mpy reported in nonaerated fluid. • Aeration may cause tenfold increase in corrosion rate. 	
<u>General Performance of Other Alloys:</u>	
<ul style="list-style-type: none"> • In nonaerated fluid, uniform corrosion of copper in heat transfer service is 1 to 10 mpy with severe crevice corrosion under corrosion product scale. Brasses and cupronickels are less suitable than copper for heat transfer. • Type 316 stainless steel is resistant to uniform corrosion, pitting and crevice corrosion, and stress corrosion cracking in many applications. 	

* Total chloride + sulfate + carbon dioxide species + sulfide species + ammonia species.

TABLE 4.0-6. GEOTHERMAL RESOURCE CORROSION CLASS VI

<u>Defining Parameters:</u>	
Resource type	Vapor-dominated
Noncondensable gas (Vol. percent)	Less than 5
Chloride	Less than 1 ppm (wt)
Plant inlet temperature	320 to 360°F
<u>Sites Reviewed in Section 4:</u>	
Italy - Boraciferous Region (10 sites)	
USA - The Geysers, CA	
<u>Observed Corrosion of Carbon Steel:</u>	
<ul style="list-style-type: none"> • Material test data not available in nonaerated steam carbon steel is widely used. • Aeration of steam or steam condensate causes severe corrosion. 	
<u>Generalized Performance of Other Alloys:</u>	
<ul style="list-style-type: none"> • Type 316 stainless steel susceptible to stress corrosion cracking in aerated moist stream. • Type 316 stainless steel and lead coated steel used in aerated condensate without hydrogen sulfide abatement chemicals. Hydrogen sulfide abatement chemicals increase corrosiveness of condensate. • Geothermal steam causes more severe corrosion-fatigue of 12Cr turbine blades than does boiler quality steam. 	

Site-Specific Presentation Format

Each site-specific section is divided into four parts. The first part identifies the site and discusses the mode of utilization, and the second presents the typical chemistry of the resource. The methods and results of corrosion tests are presented next, followed by operational experience, if available.

Materials test results are presented in both tabular and discussion form. The tables present information about the following modes of corrosion: uniform corrosion, pitting, crevice corrosion, and stress corrosion cracking. Intergranular corrosion and/or erosion-corrosion data are frequently included in the tables. Brief definitions of these terms, as used in this document, are presented in the following paragraphs.

Uniform Corrosion, or general corrosion, is metal loss evenly distributed over the entire metal surface. The rate of this form of attack can be determined by materials tests, and corrosion allowances can be made.

Pitting is a form of localized corrosion which causes cavities to form in the metal surface. Pitting is one of the most destructive forms of corrosion because a single perforation can cause component failure. The growth rate of individual pits varies unpredictably with time, and corrosion allowances cannot be reliably established.

Crevice Corrosion is accelerated corrosion under flanges, gaskets, rivets, or other fasteners, or under scale or other deposits. The growth rate of crevice corrosion also varies unpredictably with time, and corrosion allowances cannot be reliably established. In this handbook, pits occurring in crevices are considered to be crevice corrosion.

Stress Corrosion Cracking (SCC) refers to the sudden, delayed fracture of a material under applied or residual tensile stress resulting from the action of a chemical species specific to the material under consideration. Different key chemical species cause cracking of different classes of materials. Confusion may occur because the term SCC is used not only generically to include all forms of delayed fracture arising from tensile stress and environmental factors, but is also used by some authors to designate the delayed fracture of austenitic stainless steels caused by chloride ion.

In this document, the term SCC is used generically without differentiation with respect to causative agent in both the tables and text. In cases where it is possible to identify the actual mechanism of failure, a more descriptive term is used in the text. For example, ferrous alloys may be cracked by sulfide ion or chloride ion. In the text, these modes of SCC are designated sulfide stress cracking (SSC) and chloride stress corrosion cracking (chloride-SCC). These two modes of stress corrosion cracking are contrasted in Table 4.0-7.

TABLE 4.0-7. COMPARISON OF^a CHLORIDE-SCC AND SSC IN GEOTHERMAL ENVIRONMENTS

Chloride SCC	SSC
1. Mechanism: active path dissolution (rapid metal dissolution at crack tip)	1. Mechanism: cathodic hydrogen embrittlement.
2. Promoting species: usually chloride ion	2. Promoting species: H ₂ S in aqueous solution
3. Austenitic steels most sensitive	3. Martensitic and ferritic steels most sensitive Austenitic steels immune
4. <u>Not</u> notch sensitive	4. Notch sensitive
5. Severity increases with increasing temperature	5. Severity decreases with increasing temperature
6. ppm oxygen causes drastic increase in severity of attack	6. ppm oxygen has little if any effect on severity of attack
7. Bulk pH has little effect	7. Low bulk pH greatly accelerates failure
8. No threshold stress	8. Threshold of applied stress below which failure does not occur
9. Failure is sudden, catastrophic fracture	9. Failure is sudden, catastrophic fracture

^aChloride-SCC and SSC are subsets of stress corrosion cracking.

Intergranular Corrosion is the preferential dissolution of metal grain boundaries. Stress is not required. Failure occurs because grains fall out, and the metal loses strength.

Erosion-Corrosion is accelerated corrosion caused by high-velocity liquid or vapor. If the high-velocity stream contains droplets or particulates, this form of corrosion may be called impingement attack.

Results of corrosion tests are presented in two kinds of tables. The first is a "material selection table" which gives a general view of materials performance in a given environment. These tables are based on the results of corrosion tests. Both uniform corrosion rate and localized corrosion (pitting, crevice corrosion, and stress corrosion cracking (SCC)) are shown. Materials are classified in one of four categories (A through D) based on measured uniform corrosion rates as shown below:

Category	Measured Rate of Uniform Corrosion
A	rate $\leq$ 1 mpy
B	1 mpy $<$ rate $\leq$ 10 mpy
C	10 mpy $<$ rate $\leq$ 50 mpy
D	rate $\geq$ 50 mpy

In the screening tables, observations about localized corrosion are limited to "detected," indicated by X, or "not detected," indicated by N.

When results from more than one materials test in a specific process stream at one geothermal site are available, the results are presented in a single material selection table. Laboratory tests results are also incorporated in the table and are given in parentheses. No material selection tables are presented for lower temperature (less than 220°F) resources.

In addition to material selection tables, detailed summaries of the corrosion tests results are provided in tabular form. Uniform and localized corrosion rates are presented in numerical form. The pitting and crevice corrosion rates must be interpreted judiciously. These rates were calculated assuming a linear increase in pit or crevice depth with time. This procedure allows comparison of data obtained over a wide range of exposure times. However, localized growth rate is difficult to predict, and the assumption of a linear growth rate is not always accurate. A given pit may stop growing, grow at a slower rate for longer times, or accelerate in growth. An induction time before pit initiation is often observed, which further complicates data interpretation. As a general rule, materials which show any pitting in materials tests should be avoided.

Appendix F presents the relative cost of a broad spectrum of alloys. The compositions of alloys identified by society designation or tradename are available in Appendix G.

4.1 AHUACHAPAN, EL SALVADOR

The Ahuachapan geothermal resource is located near the town of Ahuachapan in western El Salvador. It is about 11 miles east of the Rio Paz, which forms El Salvador's international boundary with Guatemala (see Figure 4.1-1).

The geothermal resource is water-saturated (liquid-dominated) highly fractured Ahuachapan andesites. The fracturing provides the necessary permeability in the otherwise hard formation. Twenty-seven wells have been drilled at Ahuachapan to tap the 445°F water.

Typical production wells are cased from the surface to the top of the reservoir, a distance of about 1300 ft, with 9-5/8 inch casing. The 8 1/2-inch production hole through the reservoir is unlined unless sluff-in is a problem. In that case, slotted liners are used. Reinjection wells are similar to production wells except that they extend into the basement formation and are cased through the production zone (DiPippo 1979).

Exploration began at Ahuachapan in the mid-1960's. The Comision Ejecutiva Hidroelectrica del Rio Lempa (CEL) has developed this resource. The first 30 MWe generator (Unit 1) went on-line in June 1975, and the second identical unit (Unit 2) went on-line one year later.

Both Units 1 and 2 are single flash (bore-flashing) systems. Two-phase flow is separated (99.5 percent efficiency) in a Webre-type cyclone separator at the wellhead. The steam at 74 to 76 psig is transported through carbon steel pipelines to the powerhouse where the steam from five wells is combined for each of the two units. This steam passes through a second moisture separator (turbine inlet moisture separator) where the droplet content is reduced to 0.3 percent or less. The saturated steam enters the five-stage, double flow turbine at 66.4 psig and 313°F. Turbine exhaust pressure is 1.2 psia. The exhaust pressure is maintained by low level, direct contact (barometric) condensers. Noncondensable gases are extracted by two-stage steam jet ejectors.

A third unit (Unit 3), under construction, will be a dual flash system. The two-phase flow will be separated at the wellhead, and the steam will be transported to the powerhouse as is done for Units 1 and 2. It will enter the turbine at 64.5 psig and 311°F. The separated water will also be piped to the powerhouse where it will enter the second flasher. This second-flash steam will enter the low pressure (6.8 psig) section of Unit 3. Unit 3 will have a capacity of 35 MWe and will require the output of three wells.

About one-third of the wastewater at Ahuachapan is disposed of via a covered concrete channel which discharges into the Pacific Ocean,

FIGURE 4.1-1. LOCATION OF AHUACHAPAN GEOTHERMAL RESOURCE

about 47 miles away. The rest of the fluid is reinjected into the basement rock (DiPippo 1979).

4.1.1 Fluid Chemistry

The Ahuachapan geothermal fluid is a neutral chloride water containing about 18,400 ppm total dissolved solids (TDS). Flow from the well is two-phase. At the normal separation pressure (66 to 78 psig), the steam fraction is about 17 percent. The separated liquid fraction is about 83 percent. The separated liquid fraction has a pH of approximately seven and contains approximately 10,000 ppm chloride. The composition of this fluid is presented in Table 4.1-1. The separated (waste) fluid is supersaturated with silica and contains high levels of boron and arsenic (140 ppm boron and 7.8 ppm arsenic). The concentrations of boron and arsenic pose environmental hazards.

The separated steam from the wellhead separator contains less than 0.5 percent droplet carryover moisture. Noncondensable gas concentrations are also very low. Total gas is about 1330 ppm by volume or 3200 ppm by weight (CEL personal communication). The composition of this gas is presented in Table 4.1-2. The data represent the range in composition over one year for Well Ah-4, a typical production well.

4.1.2 Corrosion Tests

Weight-loss coupon studies in support of the design of Units 1 and 2 were performed in 1970-1971 by CEL. These tests are discussed below and are summarized in Table 4.1-3.

Methods

The uniform corrosion rate of 24 alloys was determined by weight-loss coupon methods. The coupons were exposed to seven geothermal environments at one well at Ahuachapan. These environments are described as two-phase bore fluid, nonaerated separated water, nonaerated separated steam, wet nonaerated steam, wet aerated steam, nonaerated condensate, and aerated condensate (CEL personal communication). The temperature, pressure, and chemistry of the test environments are not known, but it is assumed that these environments simulate the actual operating conditions.

Steam was taken from the Unit 2 turbine inlet moisture separator for the tests in steam. The composition of this steam is given in Table 4.1-4. The temperature in the low velocity test chamber was 201° to 205°F. Velocity is not known.

TABLE 4.1-1. RANGE OF COMPOSITION OF SEPARATED WATER FROM
WELL AH-4 AT AHUACHAPAN^a

COMPONENTS	CONCENTRATION
<u>Key Species</u> (ppm):	
pH	6.9 - 7.1
Chloride ion (Cl^-)	9624 - 9914
Sulfate ion (SO_4^{2-})	39.2 - 43.7
Bicarbonate ion (HCO_3^-)	21.4 - 27.1
Carbonate ion (CO_3^{2-})	—
Hydrogen sulfide (H_2S)	—
Ammonia (NH_3)	—
<u>Other Species</u> (ppm):	
Silica (SiO_2)	517 - 541
Sodium ion (Na^+)	5250 - 5390
Potassium ion (K^+)	720 - 790
Magnesium ion (Mg^{2+})	0.07 - 0.09
Boron (B)	136 - 145
Arsenic (As)	7.83

^aSeparated at 66 to 78 psig.

— : Data not available

Source: Comisión Ejecutiva Hidroelectrica del Rio Lempa (CEL)
1979

The steam from the low-velocity chamber was condensed to provide nonaerated condensate. The chemistry of this environment is unknown except for pH. The pH was 4.9 to 5.6. Temperature was 90° to 113°F.

This condensate flowed through an aerator into the next test chamber. The chemistry of this environment is unknown except that pH was 5.1 to 5.7. The temperature was 75° to 111°F.

TABLE 4.1-2. RANGE OF COMPOSITION OF SEPARATED STEAM FROM A
TYPICAL PRODUCTION WELL AT AHUACHAPAN^a

COMPONENT	CONCENTRATION	
	ppm (vol)	ppm (wt)
Carbon dioxide (CO ₂)	864 - 1648	2111 - 4025
Hydrogen sulfide (H ₂ S)	4.19 - 66.9	79.2 - 127.
Ammonia (NH ₃)	0.340 - 1.20	0.321 - 1.14
Nitrogen (N ₂)	1.90 - 30.7	2.953 - 47.7
Hydrogen (H ₂)	2.09 - 2.02	0.234 - 0.226
Droplet Carryover	—	5000

^aFrom Well Ah-4, separated at 66 to 78 psig

SOURCE: CEL 1979

Liquid from the drain of the Unit 2 moisture separator was also used as a test environment. The chemistry of this stream is presented in Table 4.1-5. The temperature ranged from 176° to 212°F.

Tests were also performed in cooling water. Table 4.1-6 presents typical chemistry of this water. Normal temperature for this stream is 82° to 97°F.

Results

The one- and three-month corrosion rate data for the seven test environments are presented in Tables 4.1-7 and 4.1-8. Only uniform corrosion data are available at this time. No information about pitting, crevice corrosion, or stress corrosion was reported. In some cases large differences were observed between one- and three-month test results, indicated in Table 4.1-7. Due to the political situation within El Salvador, it has not been possible to obtain clarification of the indicated results.

4.1.3 Operating Experience

The Ahuachapan Geothermal Power Plant produced almost one-third of the electric power generated in El Salvador in 1977. The successful operation of the Ahuachapan plant has made it a reliable part of the electricity supply system of El Salvador. The plant is reported to be

TABLE 4.1-3. SCREENING TABLE FOR AHUACHAPAN (UNIFORM CORROSION ONLY)^a

MATERIAL TESTED	NONAERATED ENVIRONMENTS					AERATED ENVIRONMENTS	
	Two-Phase Fluid	Separated Water	Dry Steam	Wet Steam	Steam Condensate	Wet Steam	Steam Condensate
<u>Low Alloy Steels</u>							
Carbon (1018)	A	A	B	B	B ^e	B ^e	C ^{6c}
Cr-Mo (4130)	--	--	A	B	B	B ^e	
Cr-Mo-V ^b	--	--	A	B	B	C	C
<u>Stainless Steels</u>							
AISI T403	--	--	--	A	A ^e	A	B
AISI T410	A	A	A	A	B ^e	A	B
FV 520 ^d (S) ^c	--	A	A	A	A	A	A
FV 702 ^d	A	A	A	A	A	A	A
AISI T304	A	A	A	A	A	A	A
AISI T316	A	A	A	A	A	A	A
AISI T321	A	A	A	A	A	A	A
AISI T347	A	A	A	A	A	A	A
USS 18-18-2	A	--	A	A	A	A	A
Carpenter 20-Cb3	A	A	A	A	A	A	A
<u>Nickel Based Alloys</u>							
Incoloy 825	A	A	A	A	A	A	A
Monel 400	A	B	B	B	A	B	B
Monel K500	B	B	B	A	A	C	B
<u>Copper Based Alloys</u>							
Deoxidized Copper	C	C	A	A	B	C	B
70-30 Brass	B	B	A	A	A	C	C
Al-Brass	B	B	A	A	A	B	B
<u>Aluminum Based Alloys</u>							
1100	--	B	C	A	B ^e	A	A
5052	--	B	--	A	B ^e	A	A
6063	--	B	--	A	B ^e	A	A
<u>Other Metals</u>							
Titanium	--	--	A ^e	A	A	A	A
Lead	--	--	--	A	A	B	B

^a No pitting, crevice corrosion, or stress corrosion cracking data are available.

^b rotor alloy unspecified composition

^c 15.6Cr, 5.5Ni, 1.7Mo, 2.0Cu, 0.05C annealed

^d 15.6Cr, 2.5Ni, 1.1Mo, 0.6Nb, 0.03C annealed

^e Unconfirmed rating

Key to Table

A - general corrosion rate <1.0 mpy

B - general corrosion rate >1.0 mpy but <10 mpy

C - general corrosion rate >10 mpy but <50 mpy

D - general corrosion rate >50 mpy

-- no data available

Source: CEL 1979

TABLE 4.1-4. COMPOSITION OF STEAM FROM UNIT 2 TURBINE INLET
MOISTURE SEPARATOR AT AHUACHAPAN

COMPONENT	CONCENTRATION	
	ppm (Vol)	ppm (Wt)
Hydrogen sulfide (H ₂ S)	54.32	102.8
Carbon dioxide (CO ₂)	1112.0	2716.0
Hydrogen (H ₂)	1.117	0.1250
Nitrogen (N ₂)	6.520	10.18
Ammonia (NH ₃)	.940	0.8887
Moisture ^a	- -	3000

^adroplet carryover

Source: CEL 1979

essentially free of major breakdowns (DiPippo 1979). In 1979 the availability factor based on forced outages was 95 percent. This factor was reduced to 84 percent when scheduled outages for maintenance are included.

4.1.3.1 Well Casing and Wellhead Equipment

Well casings at Ahuachapan are API grade J-55 casing. This low strength "sour service" casing has been satisfactory at Ahuachapan. The wells are cemented with Portland cement, and no problems have been reported.

Erosion of the gates of wellhead valves is a major problem. The very expensive master wellhead valve is protected by two secondary valves, one in the silencer bypass line and one in the wellhead-to-separator line. All valves are carbon steel gate valves. The secondary valves are cycled (from full-open to full-closed and back) once each month and survive about five or six cycles before erosion of the gates and seats causes leakage. When this occurs, the well is shut down, except for a two-inch purge line, and the eroded portions of the valves are rebuilt by welding (CEL 1979).

The flow from two of the production wells exceeds the 770,000 lbm/hr capacity of the wellhead separators. Initially these wells were throttled by the steam separator valve. The gates of the valves (one at

TABLE 4.1-5. ANALYSIS OF WATER FROM UNIT 2 TURBINE INLET MOISTURE
SEPARATOR AT AHUACHAPAN

COMPONENT	CONCENTRATION
<u>Key Species (ppm):</u>	
pH	5.8
Chloride ion (Cl^-)	2.28
Sulfate ion (SO_4^{2-})	2.90
Bicarbonate ion (HCO_3^-)	—
Carbonate ion (CO_3^{2-})	0
Hydrogen sulfide (H_2S)	—
Ammonia (NH_3)	—
<u>Other Species (ppm):</u>	
Sodium ion (Na^+)	0.025
Potassium ion (K^+)	0.030
Calcium (Ca)	0.65
Magnesium (Mg)	0.012
Boron (B)	1.42
— No data available	

Source: CEL 1979

each well) were rapidly destroyed. Flow from these wells is now controlled by austenitic stainless steel (grade not known) orifices. It has been reported that erosion of these orifices is "slight" (CEL 1979).

Serious problems occur with the austenitic stainless steel (unknown grade) splash plate in the base of the silencer. It has been reported that the plate erodes and becomes detached from the concrete it is protecting. Repairs have been required every six months to one year (CEL 1979). In light of the temperature and aeration of this environment, chloride stress corrosion cracking may have also contributed to early failure.

TABLE 4.1-6. COMPOSITION OF COOLING WATER AT AHUACHAPAN

COMPONENT	CONCENTRATION
<u>Key Species (ppm):</u>	
pH	6.8 - 8.4
Chloride ion (Cl^-)	21 - 52
Sulfate ion (SO_4^{2-})	122 - 168
Bicarbonate ion (HCO_3^-)	9.0 - 123
Carbonate ion (CO_3^{2-})	—
Hydrogen sulfide (H_2S)	—
Ammonia (NH_3)	—
Dissolved oxygen (O_2)	0.2 - 7.6
<u>Other Species (ppm):</u>	
Silica (SiO_2)	1.7 - 3.6
Sodium ion (Na^+)	85 - 141
Potassium ion (K^+)	0.1 - 0.6
Calcium (Ca^{+2})	2.5 - 7.7
Magnesium (Mg^{+2})	0.1 - 0.3

— Data not available

Source: CEL 1979

4.1.3.2 Steam Transport Pipeline

No problems have been reported with the carbon steel transport lines. These lines are designed with a 100 mil corrosion allowance for 30 years service.

4.1.3.3 Turbines

It has been reported (CEL 1979) that no failures of 12 Cr turbine blades have occurred in Units 1 or 2. The composition of inlet steam for Unit 2 is presented in Table 4.1-4.

TABLE 4.1-7. UNIFORM CORROSION RATES OF MATERIALS AFTER ONE MONTH EXPOSURE AT AHUACHAPAN

MATERIAL TESTED	UNIFORM CORROSION RATE (mpy)						
	Nonaerated Two-Phase	Nonaerated Separated Water	Nonaerated Separated Steam	Nonaerated Wet Steam	Aerated Wet Steam	Nonaerated Condensate	Aerated Condensate
<u>Low Alloy Steels</u>							
Carbon (1018)	0.272	0.398	1.35	—	7.21 ^e	2.57 ^f	42.6
Cr-Mo (4130)	—	—	0.276	9.30	5.41 ^e	3.21	37.36
Cr-Mn-V ^a	—	—	—	1.60	4.53 ^e	2.81	—
<u>Stainless Steels</u>							
AISI T403	—	—	—	—	—	—	—
AISI T410	0.022	0.0118	G	0.0168	0.345	0.296 ^f	0.909
FV 520 (SP)	—	—	—	0.0104	0.0479	0.0120	0.0155
FV 702 ^c	G	—	—	0.00480	0.102	0.0161	0.0129
AISI T304	0.00236	—	0.0094	0.00740	0.00866	0.0246 ^g	0.0117
AISI T316	0.00670	—	0.0102	0.0244	0.00787	0.0165	0.0183
AISI T321	0.0114	G	0.0217	0.0255	0.0193	0.0130	0.0128
AISI T347	0.0094	G	0.0138	0.0203	0.00906	0.0120	0.0101
USS 18-18-2 ^d	0.00670	—	—	0.0104	—	0.00858 ^g	0.0113
Carpenter 20-Cb3	0.00236	G	0.0091	0.00484	0.00866	0.00301	0.00724
<u>Nickel-Based Alloys</u>							
Incoloy 825	G	G	0.0106	0.00957	0.00945	0.00937	0.0101
Monel 400	0.129	1.81	3.35	0.768	8.43	0.148	5.67
Monel K500	1.64	1.64	1.76	0.591	4.29	0.221	1.86
<u>Copper-Based Alloys</u>							
Deoxidized Copper	36.1	27.5	0.630	0.587	27.2	0.862	9.37
70-30 Brass	0.980	1.56	0.278	0.237	23.7	0.175	12.0
Al-Brass	0.913	1.41	0.366	0.237	7.80	0.133	6.87
<u>Aluminum-Based Alloys</u>							
1100	—	4.41	LG	G	0.0571	1.85 ^g	0.415
5052	—	—	—	0.461	0.449	1.94 ^g	0.543
6063	—	—	—	0.284	0.264	1.89 ^g	0.531
<u>Other Metals</u>							
Titanium	—	—	0.00551	0.0312	0.0488	0.782	0.279
Lead	—	—	—	0.159	8.50	0.141	5.69

G : No weight loss or slight gain. Corrosion rates are very small.

LG : Large weight gain. Corrosion rate may be appreciable.

— : No data available.

^a Composition not available

^b Firth-Vickers Alloy - 15.66Cr, 5.46Ni, 1.68Mo, 1.99Cu, 0.5C (fully softened)

^c Firth-Vickers Alloy - 15.66Cr, 2.48Ni, 1.14Mo, 0.56Nb, 0.028C (fully softened)

^d US Steel - 18Cr, 18Ni, 2Si

^e Other experience indicates that these values may be low by 5 to 10 times.

^f Confirmation is being sought.

^f Confirmation of these values is being sought because of the very large increase when one month rates are compared to three month rates.

^g Confirmation of these values is being sought because of the very large decrease when one month rates are compared to three month rates.

Source: CEL 1979

TABLE 4.1-8. UNIFORM CORROSION RATES OF MATERIALS AFTER THREE MONTHS EXPOSURE AT AHUACHAPAN

MATERIAL TESTED	UNIFORM CORROSION RATE (mpy)						
	Non-aerated Two-Phase Fluid	Non-aerated Separated Water	Non-aerated Separated Steam	Non-aerated Wet Steam	Aerated Wet Steam	Non-aerated Steam Condensate	Aerated Steam Condensate
Low Alloy Steels							
Carbon (1018)	0.0843	0.262	0.508	8.63	7.34 ^e	37.7 ^f	23.0
Cr-Mo (4130)	—	—	0.307	7.54	5.7 ^f	6.39	19.1
Cr-Mo-V ^a	—	—	0.340	3.57	36.68	3.73	15.2
Stainless Steels							
AISI T403	—	—	—	0.0465	0.172	0.0249	1.18
AISI T410	0.0164	0.027	0.0402	0.0748	0.579	8.70 ^f	2.20
FV 520 (S) ^b	—	0.037	0.0102	0.0244	0.0244	0.00773	0.0256
FV 702 ^c	—	0.00969	0.0213	0.0179	0.0461	0.0187	0.00831
AISI T304	0.00523	0.000445	0.0200	0.0123	0.0213	0.00256 ^g	.00516
AISI T316	0.00295	0.00496	0.0225	0.00843	0.00724	0.0110	.00461
AISI T321	0.00480	0.0029	0.0606	0.0105	0.0204	0.00594	0.00862
AISI T347	0.00488	0.0034	0.0661	0.0181	0.0267	0.00598	0.0162
USS 18-18-2 ^d	0.00622	—	0.0299	0.00827	0.421	0.00206 ^g	.512
Carpenter 20 Cb3	0.00309	0.00200	0.00488	0.00921	0.00827	0.00535	.00776
Nickel-Based Alloys							
Incoloy 825	0.00429	0.00393	0.00665	0.00768	0.00653	0.00374	.00555
Monel 400	0.423	1.008	2.56	1.81	12.2	0.111	4.84
Monel K500	0.504	5.75	1.25	0.429	20.6	0.117	2.28
Copper-Based Alloys							
Deoxidized Copper	31.9	24.1 -	0.413	0.205	30.43	1.38	5.20
70-30 Brass	2.10	0.752	0.270	0.982	19.09	0.0807	5.12
Al-Brass ^a	5.31	0.618	0.0362	0.453	5.59	0.117	3.52
Aluminum Based Alloys							
1100	—	4.63	LG	nil	0.166	0.120 ^g	0.650
5052	—	4.33	—	0.461	0.106	0.0709 ^g	0.216
6063	—	3.43	—	0.284	0.467	0.0984 ^g	0.197
Other Metals							
Titanium	—	—	0.0815	0.0337	0.0169	0.0654	0.216
Lead	—	—	—	0.0575	4.51	0.312	6.54

LG : Large weight gain. Corrosion rate may be appreciable.
 — : No data available.

^aComposition not available

^bFirth-Vickers Alloy - 15.66Cr, 5.46Ni, 1.68Mo, 1.99Cu, 0.5C (fully softened);

^cFirth-Vickers Alloy - 15.66Cr, 2.48Ni, 1.14Mo, 0.56Nb, 0.028C (fully softened)

^dUS Steel - 18Cr, 18Ni, 2Si

^eOther experience indicates that these values may be low by 5 to 10 times.

Confirmation is being sought.

^fConfirmation of these values is being sought because of the very large increase when one month rates are compared to three month rates.

^gConfirmation of these values is being sought because of the very large decrease when one month rates are compared to three month rates.

Source: CEL 1979

Shortly after initial start-up of Unit 1, the final particulate sieve at the turbine inlet broke loose and was ingested by the turbine. The sieve was an austenitic stainless steel (unknown grade) plate with many holes machined in it. Chloride stress cracking initiated in the work-hardened metal around the holes and caused failure. The sieve was replaced (under warranty) by a fully annealed sieve which has been satisfactory.

4.1.3.4 Cooling Water System

Most of the materials problems at Ahuachapan occur in the cooling water system. Cooling water chemistry is reported in Table 4.1-8. Microbiological growth is a major problem (many organisms make sulfuric acid as a waste product). Microbiology is controlled by treatment with sodium hypochlorite. This lowers the pH and increases chloride ion concentration. Sodium hydroxide is used to adjust the pH to approximately 7.5. The exact nature of the cooling water corrosion problems was not reported (CEL 1979).

4.1.3.5 Separated (Waste) Water Disposal Systems

About two-thirds of the separated wastewater is reinjected into the basement rock underlying the geothermal reservoir. This water is maintained at greater than 300°F, and no silica precipitation problems have occurred. The water is reinjected at separator pressures (approximately 75 psig), and no booster pumps are required. No loss in reinjectability has been observed (CEL 1979).

The remaining third of the water is diverted through one of two labyrinth retention tanks where it is held up for 50 to 60 minutes. Studies have shown that silica scaling is very rapid during the time of rapid silica polymerization, but that once the silica is suspended as colloids, it will remain in solution indefinitely (Cuellar 1975). Retaining the water in a tank with minimal wall contact for one hour has been effective in preventing silica scale in the covered discharge channel to the Pacific Ocean (CEL 1979; DiPippo 1979).

4.1.3.6 Electrical System

Corrosion of copper contacts by atmospheric hydrogen sulfide has caused some problems. However, most contacts are gold. Exposed cables are aluminum. No problems with these materials have been reported.

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4.2 ICELAND - HIGH TEMPERATURE RESOURCE AREAS

Due to its abundant geothermal resources, Iceland is one of the few countries in the world where the full potential of geothermal energy is now being explored. The usable geothermal resources in Iceland have a wide range of temperatures: fluid temperatures are as low as 117°F for water used in a district heating system to nearly 540°F for water/steam mixtures used in electricity production and process heating. This wide range of temperatures divides geothermal resources in Iceland into high and low temperature areas (Bodvarsson 1964). High temperature areas (HTA's) are discussed in this section, and low temperature areas (LTA's) are discussed in Section 4.3.

HTA's have reservoir fluid temperatures greater than 300°F above a depth of 3300 feet (Gudmundsson 1976). These HTA's are located in a band across Iceland from the southwest to the northeast and are also found in the active volcanic zone. There are about thirteen HTA's in the country (Bodvarsson 1964). Of these, only six have been studied and explored. These include Hengill, Krísuvík, Svartsengi, and Reykjanes in the southwest and Krafla and Námafjall in the northeast (Gudmundsson 1976).

Fluid utilization in high temperature areas has been a relatively recent development in Iceland. Uses include district heating, electricity production, and industrial process heat supply. Table 4.2-1 shows utilization projects within the Námafjall, Krafla, Hengill, and Svartsengi high temperature areas. Their locations are shown in Figure 4.2-1. Because of the variety of utilization schemes in each of these high temperature areas, each area is discussed separately in the following section.

There are other locations in Iceland that are presently using geothermal fluids or that are in the planning stages but are not discussed here. Exploration of resources in Iceland is continuing, and several sites are being considered for district heating systems and industrial projects. The installations discussed in the following sections are those from which substantial corrosion experience has been gained.

Fluids from high temperature areas are not normally used directly, as are fluids from low temperature areas. This is due mainly to the differences in fluid composition of the two types of resources. Fluids from HTA's contain higher concentrations of silica than those from LTA's. As fluid temperature decreases (as during utilization), silica deposits may form on equipment surfaces. During flashing, precipitation of calcite can also occur. Such precipitation may eventually cause loss of fluid flow and heating capacity. Fluids from HTA's contain higher concentrations of hydrogen sulfide and carbon dioxide, which can cause corrosion. In several HTA's fluids cannot be used directly because of high chloride concentrations (Arnórsson and Sigurdsson 1974).

TABLE 4.2-1. SOME APPLICATIONS OF HIGH TEMPERATURE GEOTHERMAL RESOURCES IN ICELAND

APPLICATION	LOCATION	RESOURCE/ TEMPERATURE (°F)	UTILIZATION TEMPERATURE (°F)	TYPE ^a
District Heating	Lake Myvatn	Námafjall/413 ^b	176 - 194 ^c	Bifluid
Drying of Diatomaceous Earth	Lake Myvatn	Námafjall/500-536 ^d	361 ^d	Monofluid
Electricity Production	Lake Myvatn	Námafjall/500-536 ^d	355 ^e	-
District Heating	Hveragerdi	Hengill/392 ^b	176 - 194 ^c	Bifluid
Electricity Production	Krafla	Krafla/536-572 ^f	334 ^e	-
District Heating	Svartsengi Area (Keflavik Airport and Surrounding Area)	Svartsengi/455 ^g	185 - 257 ^h	Intimate Contact
Electricity Production	Svartsengi Area (Keflavik Airport and Surrounding Area)	Svartsengi/455 ^g	311 ^e	-

^aBifluid: Use of an intermediate isolation heat exchanger to transfer heat from the geothermal fluid to a secondary working fluid, which then transports the heat to the process.

Monofluid: Geothermal fluid is circulated to all parts of the process where geothermal heat is utilized.

Intimate Contact: Geothermal fluid is in intimate contact, by washing or immersion, with product; in this case, direct contact with steam of ground water for use in the system.

Sources: ^bThórhallsson et al. 1975

^cArnórsson and Sigurdsson 1974

^dRagnars et al. 1970

^eDiPippo 1930

^fSchwitzgebel 1979

^gArnórsson et al. 1975

^hThórhallsson 1979

FIGURE 4.2-1. UTILIZATION PROJECTS WITHIN THE NAMAFJALL, KRAFLA, HENGILL, AND SVARTSENGI HIGH TEMPERATURE AREAS

4.2.1 Námafjall

Námafjall is one of the first high temperature areas to be utilized in Iceland. Current well fluid uses include district heating of a village in the area, process heat for diatomaceous earth drying, and electricity production.

District Heating

The system at Námafjall began operation in 1971 and uses wells supplying 414°F water (Thórhallsson et al. 1975). The chemical composition of the deep well fluid and the utilized flashed fluid are shown in Table 4.2-2.

Discharge at the wellhead is separated at 150 psig. The steam is piped to the diatomaceous earth plant and the 3.0 MW electric power station (Ragnars et al. 1970). Separated water at 361°F is piped to another separator where steam is allowed to flash, leaving water at 212°F. From there the water is carried to the village through an asbestos cement line and is circulated through individual water heaters and isolation heat exchangers. Fresh water is heated in water heaters for domestic use and in isolation heat exchangers for radiator space heating.

Silica scaling problems due to use of this water have resulted in blocked heat exchangers and clogged water supply pipelines and sewer discharge lines. Heat exchangers require cleaning approximately every six months. To solve this problem, installation of a heat exchanger that will use the geothermal steam to heat fresh water to above boiling was proposed. The water will then be flashed for use in the district heating system (Thórhallsson et al. 1975). This system modification is reported to be in operation, resulting in a reduction in scaling. However, scale formation has also been reported to protect the water distribution system from corrosion (Einarsson and Rislund 1978).

Diatomaceous Earth Plant

Separated steam from Námafjall area wells is used in a variety of ways at the diatomaceous earth plant at Lake Myvatn (Lindal 1970). These include earth dryer heating, slurry heating, deicing of reservoirs in winter, and heating of slurry tanks, fuel oil, and plant buildings. Use of steam in the earth drying operation is of primary interest in this handbook since corrosion testing of carbon steel was performed before plant construction and then compared to actual corrosion in the steel steam dryers and tubes. Stainless steel (grade unknown) was used in other equipment for certain cases only. Copper and copper alloys were not used. The chemical composition of the water separated at 150 psig is shown in Table 4.2-3. Condensate chemical composition is shown in Table 4.2-4. Composition of

TABLE 4.2-2. COMPOSITION OF RESOURCE AND UTILIZED FLUIDS AT
NÁMAFJALL DISTRICT HEATING SYSTEM

FLUID CHARACTERISTICS	DEEP WELL WATER	SEPARATED WATER AT 212°F
Temperature °F	414	212
pH	7.48	10.21
Silica (ppm)	318	418
Sodium ion (ppm)	102.7	150.0
Potassium ion (ppm)	16.9	23.0
Calcium ion (ppm)	1.3	2.1
Magnesium ion (ppm)	0.02	0.04
Carbon dioxide (total) ^a (ppm)	62.2	17.9
Sulfate ion (ppm)	37.7	56.3
Hydrogen sulfide (total) ^b (ppm)	106.8	40.0
Chloride ion (ppm)	17.7	17.2
Fluoride ion (ppm)	0.9	1.2
Total Dissolved Solids (ppm)	597	879

^aCarbon dioxide + bicarbonate + carbonate

^bHydrogen sulfide + bisulfide + sulfide

Source: Thórhallsson et al. 1975

the non-condensable gases in the steam is shown in Table 4.2-5. Note the large fraction of hydrogen sulfide.

Tests on carbon steel in fluids at various conditions were conducted over a four-month period according to ASTM method A-224-46, Revision 1948. Results of these tests are shown in Table 4.2-6. Corrosion rates

TABLE 4.2-3. COMPOSITION OF FLASHED FLUID FROM STEAM SUPPLY FOR THE
DIATOMACEOUS EARTH PLANT AT LAKE MYVATN, ICELAND

FLUID CHARACTERISTICS		FLASHED FLUID
pH		9.6
Silica	(ppm)	676
Boron	(ppm)	0.59
Sodium ion	(ppm)	154.4
Potassium ion	(ppm)	30.3
Calcium ion	(ppm)	1.3
Magnesium ion	(ppm)	0.03
Total carbonates as carbon dioxide	(ppm)	86.6
Sulfate ion	(ppm)	79.0
Sulfide ion	(ppm)	106.6
Chloride ion	(ppm)	22.9
Fluoride ion	(ppm)	1.7
Total dissolved solids	(ppm)	1123

Source: Lindal 1970

TABLE 4.2-4 COMPOSITION OF CONDENSATE FROM STEAM SUPPLY FOR THE DIATOMITE
PLANT AT LAKE MYVATN, ICELAND

FLUID CHARACTERISTICS		CONDENSATE
pH		5.1
Total carbonates as carbon dioxide	(ppm)	813.2
Sulfide ion	(ppm)	194.6

Source: Lindal 1970

TABLE 4.2-5. COMPOSITON OF NONCONDENSABLE GASES IN THE STEAM SUPPLY
TO THE DIATOMACEOUS EARTH PLANT AT LAKE MYVATN, ICELAND

COMPONENT	COMPOSITION (By Volume)
Carbon dioxide	31.4%
Hydrogen sulfide	24.1%
Hydrogen	32.8%
Nitrogen	8.7%
Argon	0.2%
Methane	2.52%

Source: Lndal 1970

ranged from a minimum of 0.87 mils/yr. for dry nonaerated steam to 18.3 mils/yr. for aerated steam. Pitting was reported as slight (not quantified) for all fluids. Tests in condensate showed that nonadherent scale formed in two weeks and was flaking after four weeks (Lndal 1970).

Although the tests were performed using stationary surfaces, the steam tubes actually rotate within the earth dryer during normal operation. Inspection of the dryer tubes was conducted after two years. It was determined that the corrosion rate ranged from 1 to 2 mils/yr. Scale was evident in the tubes, but pitting was moderate. Test results and operating experience indicated that carbon steel had a long life in natural steam from this resource (Lndal 1970); however, this lifetime was not quantified.

Although no particularly severe operating problems were noted due to corrosion, scale products forming within the dryer tubes tended to fall off and clog steam traps and bleed vents. Design changes have minimized these problems (Lndal 1970).

Electricity Production

Steam separated at the well head is used to drive a small turbine at a power station built by the Laxa Power Works (Ragnars et al. 1970). It has been reported that downhole well temperatures are nearly 572F, and

TABLE 4.2-6. RESULTS OF CORROSION TESTS ON CARBON STEEL FOR DIATOMACEOUS EARTH PLANT AT LAKE MYVATN, ICELAND

FLUID	CORROSION RATE (mpy)
Steam and water	1.20
Dry steam	0.87
Aerated steam	18.3
Condensate of steam	4.07

Source: Lindal 1970

steam is delivered at 361°F. The fluid contains noncondensable gases which are approximately one percent by weight of the steam flow. The noncondensable portion is (by volume) 52 percent hydrogen sulfide, 32 percent carbon dioxide, 12 percent hydrogen, and 4 percent other gases. Total dissolved solids downhole are about 1000 ppm, of which nearly sixty percent is silica (DiPippo 1980).

The turbine is the noncondensing type with a 3.0 MW capacity. The turbine, a previously-used unit, was originally supplied with blades of BTH Helca-ATV alloy containing 10 to 12 percent chromium and 35 to 37 percent nickel. According to Ragnars et al. (1970), a new set of blades designed for existing steam conditions were ordered to replace the original blades. Durability of either set was not reported. However, no corrosion problems have been reported in carbon steel pipes used for two-phase flow or for separated steam or separated water (Einarsson and Rislund 1978).

At Námaskard (in the Námafjall area), a three-month coupon test was conducted using a test separator on a producing steam well. The average corrosion rate for carbon steel coupons in steam lines was 1.2 mpy. Pipes scaled faster than coupons. Scale in the test system was mainly pyrrhotite. However, in the past, the corrosion product had been pyrite. Scale in the separated water lines consisted primarily of silica and iron compounds. Scale in water lines was reported to be very protective (Einarsson and Rislund 1978).

4.2.2 Hengill

District Heating

Prior to 1973, the district heating system at Hveragerdi, in the Hengill HTA, used hot water wells and hot springs to heat homes and greenhouses (Thórhallsson et al. 1975). No scaling problems were noticed. In 1973 wet steam wells were connected to the existing distribution system. Temperature of the well fluid is 392°F. Water and steam from the well are piped together in steel pipes to an open tank which acts as a separator, and then to a surge tank. The separated water at 212°F flows by gravity through an earth-covered asbestos pipe to the town. Insulated steel pipes are used for the municipal distribution system. Hot water is piped to houses where it is circulated through isolation heat exchangers and water heaters. Fresh water is heated in the heat exchangers for radiator space heating and in water heaters for domestic hot water.

Fluid chemistry of the deep well water and utilized water is shown in Table 4.2-7. Silica scaling was noticed in the heat exchangers and flow control equipment soon after installation. Cleaning of scale in heat exchangers is required about every three to six months. In order to reduce silica scaling, a 35-percent dilution of the well fluid using cold water is conducted prior to flashing. The chemical composition of the diluted stream is shown in Table 4.2-7.

Corrosion testing was performed to study effects of dilution. Corrosion coupons of copper, galvanized steel, stainless steel (grade unknown), and carbon steel were exposed to the diluted fluid stream. No quantitative data were reported, but it was noted that scaling on galvanized steel was ten times greater than on the other materials tested. Inspection of heat exchanger plates after three months' exposure to both undiluted and diluted water showed that dilution reduced but did not stop scaling. Einarsson and Rislund (1978) have reported that such scale has protected the system from corrosion.

4.2.3 Krafla

Preliminary surveys of the geothermal fields near Krafla and Námafjall during 1970 to 1973 indicated that the Krafla field is considerably larger. The full power production potential of the Krafla field has been estimated at 300 to 500 MW. Both fields are parts of the same volcanic rift zone which transects Iceland from southwest to northeast. The geologic development is different in the two areas; an old, half-filled caldera contains the groundwater system at Krafla. Twenty volcanic eruptions have occurred since the end of the last glacial period. In January 1975 seven earthquakes were measured; two of them registered five on the Richter scale (Schwitzgebel 1979).

TABLE 4.2-7. COMPOSITION OF RESOURCE AND UTILIZED FLUIDS AT HVERAGERDI DISTRICT HEATING SYSTEM

FLUID CHARACTERISTIC	WELL #2, HVERAGERDI		HVERAGERDI After Dilution
	"Deep Well Water"	Separated Water at 212°F	
Temperature °F	392	212	212
pH ^a	7.76	9.58	8.95
Silica (ppm)	270	347	188
Sodium ion (ppm)	115.5	191.5	-
Potassium ion (ppm)	12.6	15.0	-
Calcium ion (ppm)	1.9	2.4	-
Magnesium ion (ppm)	0.96	0.10	-
Carbon dioxide (total) ^b (ppm)	176.0	48.0	47.8
Sulfate ion (ppm)	65.0	75.8	-
Hydrogen sulfide (total) ^c (ppm)	30.2	7.8	7.2
Chloride ion (ppm)	125.0	152.3	-
Fluoride ion (ppm)	1.9	2.1	-
Total dissolved solids (ppm)	740	879	-

^a Measured at ambient temperature

^b Carbon dioxide + bicarbonate + carbonate

^c Hydrogen sulfide + bisulfide + sulfide

-: No data available

Source: Thórhallsson et al. 1975

The Krafla plant design was finalized in early 1975, and construction started in the middle of the same year. To date a total of twelve wells has been drilled. Five of them are still operational, and one delivers superheated steam (Schwitzgebel 1979). Well depth, temperature, and steam/water ratio are as follows:

<u>Well</u>	<u>Depth</u>	<u>Temperature</u>	<u>Steam Content</u>
#6	5900 ft.	536°F	75% steam
#7	6200 ft.	536°F	70% steam
#9	4400 ft.	500°F	20% steam
#11	6950 ft.	536°F	70% steam
#12	7300 ft.	572°F	Superheated steam

The combined production capacity of these wells is between 7 and 8 MW. The low power output is due to the low permeability of the geothermal field. The field consists of two zones. Zone one reaches down to 3300 ft., and it contains calcite deposits of low permeability. The water temperature is typically 410°F. Between 3300 ft. and 3900 ft. is an impermeable layer of cap rock. Below the cap rock, waters in zone two are at temperatures of about 570°F.

The power generation system involves a dual-flash steam cycle. Both high and low pressure steams are generated at a central point and then piped to the powerhouse for use in the turbines. Each of the two turbine generators, one of which has been installed, has five stages. They are dual-pressure, double-flow in design. Steam is condensed in a direct contact condenser located immediately under the turbines. The steam turbines are designed and constructed by Mitsubishi and have a maximum capacity of 35 MW each under most favorable conditions (DiPippo 1980; Schwitzgebel 1979).

Each well produces hot water at a flow rate of 744 gal/min. The steam is produced when the water enters the high pressure (HP) steam separator under about 132 psia pressure. The well fluid flashes and separates into steam and water at 347°F. The HP steam is then directed through carbon steel piping to the powerhouse, passed through a moisture separator, and brought to the HP stages of the turbine under about 113 psia. The water effluent, the 347°F water from the HP separator, is led into the low pressure (LP) steam separator (the flasher). A second steam separation occurs at the flasher under about 32 psia and yields 248°F steam and water. The 248°F. water effluent from the LP separator is released into a concrete channel leading to the cooling pond. The steam produced in the LP separator is passed through a moisture separator and brought to the LP stages of the turbine.

The steam flows through the turbine and into the condenser where it is condensed by a cool water spray (72°F) from the cooling tower. A

small portion of the steam, about one percent, consists of non-condensable gases (carbon dioxide, hydrogen sulfide). They are released to the atmosphere through gas ejectors, intercondensers, and silencers.

In the main condenser, the pressure drops to 1.7 psia, and the steam condenses to 115°F hot water which then flows from the condenser basin to the pumps. The highly corrosive condensate is pumped by four 500 horsepower pumps, two for each condenser, through stainless steel piping to the top of the cooling towers. From there the water flows down the packed towers. Large motor-driven fans in the cooling tower shafts draw cool air through the towers. The water is cooled from 115°F to about 72°F if the outdoor temperature is 59°F.

The pressure differential between the condenser and the cold water basin in the cooling tower ensures the flow of cooling water from the basin to the condenser spray nozzles. When the outdoor temperature is very low (-22°F), the cooling process is more efficient, and the condenser vacuum increases.

The LP steam separator discharges approximately 95 gallons/sec water. On its way to the cooling pond, the water cools to 194°F. The cooling pond storage capacity is about 4.3 million cubic feet. The residence time of the wastewater in the pond is four days. During this time, most of the hydrogen sulfide is evaporated, and the silica starts to polymerize and precipitate. The effluent from the cooling pond is about 50° to 68°F and is ultimately disposed of in the Burfell lava field.

Operating Experience

As of June 1979, one 35-MW turbine had operated for a total of one year. The three operational periods were one month in 1977 (no load), six months in 1978 (6 to 8MW load), and five months in 1979 (6 to 8 MW load). The turbine was dismantled in June 1979 for inspection (Schwitzgebel 1979). Severe erosion was found on Stages One and Two. The erosion was most severe at Stage Two because steam flow to Stage One was restricted to 50 percent capacity during the operating periods. Material loss of 40 to 80 mils was observed on the edges of blades in Stage Two. Iron oxide and ferric chloride deposits 40 to 80 mils thick formed on the outer rings of Stage Three. No unusual erosion and corrosion were found on Stages Three, Four, and Five.

The erosion and the formation of deposits are believed to be caused by intermittent operation. Under normal, continuous operation a protective layer of scale 80 to 120 mils thick is formed on the inside of the carbon steel supply lines after one year of operation. The protective layer did not peel after this time period. Intermittent operation (like that in Krafla during 1977 to 1979) causes thermal shocks which results in peeling of the protective film. This freed particulate matter causes the

erosion and forms the deposits in the turbine observed during the June 1979 inspection period.

Another corrosion problem was found in the supply lines from Well #12. Well #12 supplies superheated steam at a temperature of 572°F. The condensate of this steam has a pH ranging as low as 3.1 to 3.9. Condensate water of such low pH is formed if steam from Well #12 is mixed with the colder water/steam mixtures originating from other wells and corrodes the carbon steel pipes. The outputs of Wells #12 (572°F, superheated steam) and #9 (500°F, 20 percent steam, 80 percent water) were mixed, and the supply line corroded immediately at the point of mixing. Other problem points, again caused by condensation, are areas of no flow. The chemical analysis of the steam from Well #12 is given in Table 4.2-8.

A suitable material for rupture disks still needs to be found. Inconel 600 proved unsatisfactory due to sensitivity to hydrochloric acid. Corrosion is again caused by condensation. Failures occur within hours.

The condenser is a stainless steel flat plate heat exchanger and has had no problems to date.

An additional program began in 1977 to study corrosion at Krafla. The program consisted of (1) inspecting two-phase flow lines and wellhead materials, and (2) inserting carbon steel coupons for three months in flow lines of a test separator on steam wells. Preliminary results indicate a uniform corrosion rate of 1.3 mils per year for carbon steel coupons exposed to steam and 0.51 mils per year for coupons exposed to water. No pitting was observed in the samples. Scale analysis indicated the primary constituents were iron, sulfide, and silica compounds (Einarsson and Rislund 1978).

4.2.4 Svartsengi

The Svartsengi high temperature area is located on the Reykjanes Peninsula in southwestern Iceland. Wells in the area have yielded water/steam mixtures with temperatures as high as 455°F. The geothermal fluid in the area is different from other fluids in Iceland. The chloride content is about 13,000 ppm (two-thirds the chloride content of sea water). The fluids are thought to be of seawater origin. The hot fluid contains about 400 ppm silica, which can cause scale on equipment. Chemical compositions of well fluids in the Svartsengi area are shown in Table 4.2-9.

The water is being utilized for the Sudurnes Regional Heating District, supplying the towns surrounding the Keflavik Airport (Thórhallsson 1979). The water is also used for a small electricity production facility, which supplies power for the district heating plant located near Grindavik.

TABLE 4.2-8. CHEMICAL ANALYSIS OF KRAFLA WELL NO. 12

CHARACTERISTICS	SAMPLE NO./DATE OF ANALYSIS					
	781105 11-30-78	781106 12-4-78	791003 1-15-79	791007 2-13-79	791008 3-4-79	781024 4-28-79
Pressure (psia)	164	120	129	93	116	117
Temperature (°F)	-	-	351	-	428	425
<u>KEY SPECIES:</u>						
pH Condensate ^a	-	4.92	-	-	-	-
pH Water Phase ^a	-	6.67	3.48	-	4.30	-
	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>
Chloride	-	21.6	112	174	-	-
Sulfate	-	10.7	-	27.4	-	-
Carbon dioxide	7,830	19,000	17,100	-	18,020	18,020
Hydrogen sulfide	68	800	1,130	-	1,054	1,054
<u>OTHER SPECIES:</u>						
Hydrogen	43	50	40	-	45	45
Silica	-	68	28	23	-	6
Boron	-	0.30	0.46	-	-	-
Sodium	-	20.2	0.17	-	0.13	4.0
Potassium	-	4.94	-	1.6	-	-
Calcium	-	2.13	0.43	3.86	-	-
Magnesium	-	0.01	0.04	-	-	-
Iron	-	0.133	26	87	-	-
Fluorine	-	0.135	0.24	-	-	-

^a Measured at ambient temperature

-: Data not available

Source: Schwitzgebel 1979

TABLE 4.2-9. COMPOSITION OF RESOURCE FLUID AT SVARTSENGI

FLUID CHARACTERISTIC	WELL 3 (1300 ft. deep)	WELL 5 (5000 ft. deep)
Temperature °F	455	460
pH	-	6.15 ^a
Silica (ppm)	420	438
Boron (ppm)	7.8	-
Sodium ion (ppm)	6,448	6,008
Potassium ion (ppm)	1,032	958
Calcium ion (ppm)	924	924
Magnesium ion (ppm)	1.3	7.3
Carbon dioxide (total) ^b (ppm)	163.3	433.0
Sulfate ion (ppm)	31.4	32.5
Hydrogen sulfide (total) ^b (ppm)	4.4	2.5
Chloride ion (ppm)	12,888	11,433
Carbon dioxide in steam ^c (ppm)	486.1	1,288.0
Hydrogen sulfide in steam ^c (ppm)	12.1	7.3

^a Measured at 460°F.

^b Includes dissociated as well as undissociated carbonate and sulfide.

^c These concentrations refer to complete transfer of the volatiles to the steam phase, which is a fair approximation when steam is produced by flashing to temperature as low as 122°F.

—: No data available

Source: Arnorsson et al. 1975

District Heating

Because of scaling problems using silica-laden geothermal water to heat fresh water, in 1974 pilot plant tests were conducted to investigate various heat exchange methods (Arnórsson et al. 1975). One method was developed that involved direct mixing of fresh water with separated steam from the geothermal well fluid. Fluid composition of this system is shown in Table 4.2-10. In the present system the geothermal fluid is piped as two-phase flow from the supply wells to two steam separators placed in series. High pressure (HP) steam is piped to two back pressure turbines (1 MW each) for electricity generation. The steam is then condensed in a plate heat exchanger. Spent brine from the HP and LP separators goes to surface disposal. LP steam is routed to a direct-contact condenser where the fresh water is preheated from 41°F to 149°F. The water is then piped to another heat exchanger (intercooler) and to the turbine condenser/heat exchanger. The water is further heated to 221°F during this step before deaeration. The water is then either cooled (in the intercooler) to 185°F for direct use in Grindavik or heated to 257°F by HP steam in another plate heat exchanger for use in Keflavik (Thórhallsson 1979).

Carbon steel is used for piping the brine and steam. Stainless steel and fiberglass pipes are used to pipe the heated fresh water prior to deaeration and for piping steam condensate. Plate heat exchangers are constructed of titanium and stainless steel (Thórhallsson 1979). After deaeration, the water used in the heating systems is considered noncorrosive to carbon steel, galvanized steel, and copper (Einarsson and Rislund 1978). Very few materials problems have been encountered thus far. Some of the piping is fiberglass, and the elbows have leaked badly. Some valve problems have been encountered. Rough valve stems have been honed to prevent wear problems. Small ball valves are simply replaced as the system design allows rapid change (Thomas 1979). Some corrosion of carbon steel from the HP condensate has been noted, although no quantitative data is reported.

Electricity Production

The turbines at the Grindavik power plant utilize 311°F steam from the 455°F resource. The only major problem to date is the rapid failure of turbine rupture disks. The failure has been traced to a design feature that causes a resonant frequency in the system. The design feature is being changed (Thomas 1979).

The current power output of the Grindavik plant is 1.2 MW (Thórhallsson 1979).

TABLE 4.2-10. COMPOSITION OF WATERS AS USED IN THE DIRECT MIXING
PROCESS AT SVARTSENGI

FLUID CHARACTERISTICS	COLD WATER 41°F	PREHEATED WATER 104°F	HEATED WATER 257°F
pH	7.39	7.50	8.03
Silica (ppm)	32.8	28.1	26.1
Sodium ion (ppm)	95.2	-	79.8
Potassium ion (ppm)	4.7	-	4.0
Calcium ion (ppm)	19.6	-	16.1
Magnesium ion (ppm)	17.4	-	14.0
Carbon dioxide (total) (ppm)	47.1	44.5	30.0
Sulfate ion (ppm)	29.6	-	27.6
Hydrogen sulfide (total) (ppm)	<0.1	<0.1	0.24
Chloride ion (ppm)	206.0	-	172.5
Fluoride ion (ppm)	0.15	-	0.20

—: No data available

Source: Arnórsson et al. 1975

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4.3 ICELAND - LOW TEMPERATURE RESOURCE AREAS

The temperature of reservoir fluids in low temperature resource areas (LTA's) is 300°F or less at 3300 feet or shallower. The temperature range is generally from 117°F to nearly 250°F at the 250 LTA's in Iceland (Bodvarsson 1964).

The use of LTA geothermal fluids for space heating began in the 1920's. More than 50 percent of Iceland's population benefitted from space heating through the district heating systems by 1975 (Einarsson 1975). By 1980, 70 percent of the population will use space heating due to expansion of present systems and new district heating systems (Gudmundsson 1976).

District heating systems are the largest users of LTA geothermal fluids in Iceland. Agriculture and industry also use the LTA's. Some of the various applications of geothermal resources are given in Table 4.3-1.

The location of some LTA projects in Iceland is indicated in Figure 4.3-1. District heating systems supply hot water and/or steam for space heating in several towns and villages. The largest of these is the Reykjavik District Heating System, serving nearly 88,000 people in 1974. Agricultural uses include space heating of greenhouses and heating of waters used in fish breeding operations. Industrial use is limited to furnishing process heat for drying operations. These include fish and seaweed drying.

In most district heating systems, water from low temperature areas is used directly in radiators within buildings and for hot domestic water. At Selfoss, isolation heat exchangers are used for the radiator systems (Einarsson and Rislund 1978). It has been reported that fluids from LTA's are relatively free of dissolved substances that cause corrosion of material and fouling of equipment surfaces (Gudmundsson 1976).

The following sections discuss the materials testing that has been performed and operational experiences that have been gained from some of these LTA systems. The fact that any utilization projects are not mentioned in the following sections indicates the lack of quantitative corrosion data from those projects.

4.3.1 Fluid Chemistry

Fluids from LTA's have been reported as containing less dissolved solids than those from high temperature resource areas (HTA's). The fluids are generally alkaline and reducing, as are those from HTA's (Kristinsson and Jonsson 1971). Table 4.3-2 lists the range of analyses from some of these low temperature systems.

TABLE 4.3-1. SOME APPLICATIONS OF LOW TEMPERATURE GEOTHERMAL RESOURCES IN ICELAND

USE	LOCATION	RESOURCE TEMPERATURE °F	UTILIZATION TEMPERATURE °F	SYSTEM	TYPE
District Heating	Reykjavik	187-262 ^a	176 ^a	Pump, Circulate ^b Dispose to Waste	Monofluid
	Olafsfjorder	118-133 ^c	117 ^d	-	Monofluid
	Selfoss	~176 ^c	180 ^d	-	Bifluid
	Saudarkrokur	~158 ^c	167 ^d	-	Monofluid
	Dalvik	-	131 ^d	-	Monofluid
	Husavik	212 ^f	176 ^d	-	Monofluid
	Hvammstangi	-	176 ^d	-	-
	Seltjarnarnes	-	183 ^d	-	Monofluid
	Hrisey	-	145 ^d	-	Monofluid
	Mogilsa	-	144 ^d	-	Monofluid
	Hunavellir	-	124 ^d	-	Monofluid
	Storutjarnir	-	149 ^d	-	-
Drying of Seaweed	Reykholar	212 ^g	-	-	-
Greenhouse Heating	Various areas	Varies	185-194 ^f	-	Monofluid
Fish Breeding	Various areas	158 ^g	54-57 ^g	-	-

-: No data available

Sources: ^aZöega 1974^bGudmundsson 1976^cEinarsson 1973^dEinarsson et al. 1977^eEinarsson and Rislund 1978^fKristinsson and Jónsson 1971^gMatthiasson 1970

FIGURE 4.3-1. LOCATION OF LTA PROJECTS IN ICELAND

TABLE 4.3-2. COMPOSITION OF FLUIDS AS USED IN SOME LOW TEMPERATURE
GEOTHERMAL HEATING SYSTEMS IN ICELAND

FLUID CHARACTERISTICS		CONCENTRATION (ppm)
Temperature °F		117 - 262
pH		7.90 - 10.25
Oxygen	(O ₂)	0.0 - 4.1
Bisulfide	(HS ⁻)	0.0 - 2.4
Sodium	(Na ⁺)	32.0 - 337
Potassium	(K ⁺)	0.3 - 9.3
Calcium	(Ca ²⁺)	1.9 - 105
Magnesium	(Mg ³⁺)	0.0 - 0.2
Chloride	(Cl ⁻)	7.7 - 528
Sulfate	(SO ₄ ²⁻)	2.1 - 180
Carbonate	(CO ₃ ²⁻)	0.6 - 13.7
Bicarbonate	(HCO ₃ ⁻)	13.7 - 131
Fluoride	(F ⁻)	0.1 - 5.0
Silica	(SiO ₂)	54.0 - 186
Total Dissolved Solids (ppm)		153 - 1382

Source: Einarsson et al. 1977

4.3.2 Material Tests

In 1972, a program to study corrosion in low temperature district heating systems was started. The discussion in this section is based on unconfirmed translations of numerical data from two reports from this program (Hermannsson et al. 1975; Einarsson et al. 1977).

The corrosion test apparatus was three composite sections connected in series. Each section consisted of three 17-inch long pipes of different materials. The pipe materials were 0.708-inch diameter copper, 0.75-inch diameter mild steel, and 0.75-inch diameter galvanized steel. A water meter measured the flow through the test loop. Water flow rate was set at about 1.3 gallons per minute. The actual rate varied considerably throughout the test duration for the different systems.

Two carbon steel corrosion coupons were placed in each section. Inspection of coupons and pipe materials was made of the first section after one year; the second section after two years; and the third section after three years. The coupons were used to determine average corrosion rate by weight loss (average weight loss for two coupons). Pitting depth for the coupons were also measured. The pipes were cut lengthwise and inspected as well. Corrosion products and scale were weighed and analyzed. Water samples of the fluids being tested were collected at the beginning of the test and after removal of each section. These samples were then analyzed.

Results of the test program are presented in Table 4.3-3 and 4.3-4. Temperatures and chemical composition of fluids from each system tested, as well as uniform corrosion rate and pitting rate of carbon steel, are included. The maximum pitting depth (average of three deepest measured pits) is calculated from the reported pitting rate and the test duration.

The concentration of oxygen and sulfide in low temperature waters affects corrosion. Oxygen and sulfide do not exist in equilibrium in the same fluid; therefore, the systems may be divided into oxygen and sulfide types. Results of uniform corrosion tests indicate almost an order-of-magnitude difference between oxygen-contaminated waters and sulfide-bearing water of similar pH. The results from each of the sites tested are discussed in detail below. Selfoss, Dalvik, Hrisey, and Olafsfjordur are considered oxygen-containing systems; the remainder are sulfide systems.

Oxygen-Containing Systems

Selfoss - Of the four oxygen-containing systems, Selfoss has the lowest uniform corrosion rate (0.63 and 0.67 mils/yr.) for carbon steel coupons. This is attributed to the low oxygen concentration (less than 100 ppb), although the temperature (180°F), pH (8.75), and chloride concentration of the fluid are high. The uniform corrosion rate is essentially constant with time for the two sets of coupons inspected. Pitting rates, however, are among the highest of the systems tested. Pitting depth plotted against the number of days exposure is shown in Figure 4.3-2. Severity of attack may be related to the high chloride concentration, which can accelerate pitting. Elemental analysis of incrustations indicates that they are primarily iron compounds and silica in carbon steel pipes; zinc

TABLE 4.3-3. FLUID CHARACTERISTICS OF LOW TEMPERATURE WATERS USED FOR DISTRICT HEATING IN ICELAND

LOCATION	TEMPERATURE °F	FLUID CHARACTERISTICS									
		pH	Oxygen (O ₂)	Bisulfide (HS ⁻)	Chloride (Cl ⁻)	Sulfate (SO ₄ ²⁻)	Carbonate (CO ₃ ²⁻)	Bicarbonate (HCO ₃ ⁻)	Ammonia (NH ₃)	Calcium (Ca ²⁺)	Silica (SiO ₂)
			ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm
Selfoss	180	8.75	<0.1	<0.1	245	51.4	1.0	40.0	-	25.5	69.5
Dalvík	131	10.25	0.2	0	9.3	13.8	13.7	13.7	-	1.9	90.0
Hrísey	145	9.30	0.3	0	342	42.0	2.0	14.0	-	42.0	54.0
Olafsfjörður	117	10.10	4.1	0	5.7	2.1	12.0	15.0	-	2.6	60.0
Hunavellir	124	9.50	0	2.1	7.7	59.1	8.0	38.8	-	7.3	114
Húsavík	176	9.55	0	1.0	10.1	27.8	9.6	46.0	-	9.1	186
Reykjahlíð	187	9.55	0	1.6	13.2	22.4	7.6	33.2	-	2.4	86.5
Reykir	163	9.70	0	0.4	15.2	15.0	10.0	30.0	-	2.8	74.5
Storutjarnir	149	9.65	0	2.4	17.1	30.9	7.4	29.5	-	2.4	110
Saudarkrokur	167	9.85	0	0.5	19.1	40.7	8.6	20.0	-	3.5	77
Bólholt	181	9.55	0	0.3	27.2	17.1	7.0	27.0	-	2.4	128
Mogilsa	144	7.90	0	1.5	27.7	49.2	0.6	131	-	9.8	122
Hvammstangi	176	9.45	0	0.4	141	137	3.0	17.0	-	27.8	98.5
Seltjarnarnes	183	8.50	0	0.1	528	180	0.6	20.0	-	105	117

--: Data not available

SOURCE: Einarsson et al. 1977

TABLE 4.3-4. MILD STEEL CORROSION TEST RESULTS FROM LOW TEMPERATURE WATERS USED FOR DISTRICT HEATING IN ICELAND

LOCATION	TEST DURATION (days)	CORROSION RESULTS		
		Uniform Corrosion (mpy)	Pitting (mpy)	Maximum Pitting Depth (mils)
Selfoss	259	0.63	12.6	8.94
	707	0.67	13.2	25.6
Dalvik	279	2.2	10.8	8.28
	448	2.2	9.61	11.8
	672	2.0	10.7	19.6
Hrisey	342	9.06	27.6	25.8
Olafsfjordur	390	1.5	7.48	7.99
	838	1.2	5.51	12.7
Humavellir	278	0	0	0
	671	0.09	9.41	17.3
	841	0.21	10.2	23.6
Husavik	280	0.05	4.72	3.62
	672	0.02	3.2	5.94
Reykjahlid	283	0.11	2.4	1.8
	688	0.63	3.3	6.3
Reykir	280	0.03	2.0	1.5
	645	0.04	0	0
Storutjarnir	443	0.10	6.69	8.12
Saudarkrokur	279	0.19	7.87	6.02
	672	0.33	5.35	9.86
Bolholt	250	0.04	2.0	1.3
	616	0.06	2.6	4.3
Mogilsa	294	1.6	20.1	16.2
	722	0.91	8.98	17.8
Hvammstangi	388	0.19	4.13	4.39
	782	0.21	4.76	10.2
Seltjarnarnes	279	0.02	0	0
	593	0.01	0	0

SOURCE: Einarsson et al. 1977

FIGURE 4.3-2. PITTING OF MILD STEEL IN OXYGEN-BEARING WATERS
Source: Einarsson, Elisson, Sigurdsson, and
Hermannsson 1977

compounds and silica in galvanized steel pipes; and copper compounds in copper pipe.

Dalvik - The corrosion rate (2.2, 2.2, and 2.0 mils/yr) for three sets of coupons at Dalvik is almost three times the rate at Selfoss. This may be due to the higher oxygen concentration (0.2 ppm), though temperature is considerably lower (131°F). The pitting rate for each test series is very nearly the same except for the second set removed at 448 days. Data for this test set indicated that the well water had changed, resulting in a lower oxygen concentration and higher temperature. Maximum pitting depths for these three sets of coupons are shown in Figure 4.3-2. Incrustations are mainly iron and silica in mild steel pipes and zinc and silica in

galvanized steel pipes. No corrosion of copper pipes was reported in this oxygen system.

Hrisey - Only a limited amount of data from a single year's test is available for this site. The uniform corrosion rate for the one set of coupons is the highest of any of the systems (9.06 mils/yr). The pitting rate is also the highest. This may be due to the high chloride concentration (342 ppm) and the oxygen concentration (0.3 ppm). The maximum pitting depth of 25.8 mils is the highest of any of the systems for a coupon set pulled at the end of this length test duration (342 days). This is illustrated in Figure 4.3-2. No data was reported for scale analysis in pipes of different materials in this system.

Olafsfjordur - The uniform corrosion rates for mild steel coupons are 1.5 and 1.2 mils/yr. The oxygen concentration at Olafsfjordur is the highest (4.1 ppm) of any of the systems. The low temperature (117°F) of the Olafsfjordur fluid may be related to the difference in rates between this system and other oxygen systems. The pitting rates (7.48 mils/yr. and 5.51 mils/yr.) are the lowest of any of the oxygen systems. Maximum pitting depths are shown in Figure 4.3-2. Olafsfjordur is the only oxygen system that shows a definite decrease in pitting rate with increased time exposure. Very little corrosion product was found in mild steel pipes during the first inspection, and none was found during the second. Corrosion products in galvanized steel pipes consisted mainly of zinc and silica. No corrosion products were found in copper pipes.

Sulfide-Containing Systems

Hunavellir - The data available on this sulfide system is confusing because of translation difficulties with the original reports. It is reported that the test loop at Hunavellir was not operating for an unspecified period. It was possibly turned off because the temperature of the test loop fluid was found to be lower than normal. This may be the reason for no corrosion in 278 days. Subsequent inspection at 671 and 841 days showed uniform corrosion rates of 0.09 and 0.21 mils/yr., respectively. The pitting rate and depth (Figure 4.3-3) for Hunavellir is very similar to oxygen systems. This may be due to the high sulfide concentration (2.1 ppm). Incrustations are iron and silica in mild steel pipes and sulfide compounds in copper pipes. Corrosion product samples from galvanized steel were reported to be small and results were inconclusive. Zinc and silica appeared to be the main corrosion products.

Husavik - This system shows a decrease in both the uniform corrosion rates (0.05 to 0.02 mils/yr.) and pitting rates (4.72 to 3.2 mils/yr.) as time increases. Maximum pitting depth as a function of time is shown in Figure 4.3-3. Analysis of scale in pipes shows that it is mainly iron in carbon steel pipes and sulfides in galvanized steel pipes and copper pipes.

FIGURE 4.3-3. PITTING OF MILD STEEL IN SULFIDE-BEARING WATERS
Source: Einarsson, Elisson, Sigurdson, and Hermannsson 1977

Reykjahlid - Reykjahlid is one of the areas which supplies the Reykjavik District Heating System (Lindal 1977); the others are Reykjavik and Bolholt. Test results show an increase with time in both the uniform rate (0.11 to 0.63 mils/yr.) and pitting rate (2.4 to 3.3 mils/yr.). Pitting depth is shown in Figure 4.3-3. Corrosion products in copper pipes were mainly copper compounds. Very little or no corrosion products were found in carbon steel and galvanized steel pipes.

Reykjavik - Corrosion testing shows that uniform rates increase slightly from 0.03 to 0.04 mils/yr. at 280 and 645 days, respectively. The pitting depth, however, apparently decreases from 2.0 to zero mils/yr. The reason for such results is not indicated. Pitting depth is illustrated in

Figure 4.3-3. Corrosion products were found primarily in copper pipes at Reykir and were copper compounds.

Storutjarnir - Results from one coupon test set were available for this system. The sulfide concentration (2.4 ppm) of the fluid was the highest of the sulfide systems. Uniform corrosion was 0.10 mils/yr., and pitting was 6.69 mils/yr. This pitting rate is similar to other sulfide systems, as shown in Figure 4.3-3. Incrustations were mainly iron and silica in carbon steel pipes; zinc and silica in galvanized steel pipes; and copper and sulfide compounds in copper pipes.

Saudarkrokur - The uniform corrosion rate for this system increased from (0.19 to 0.33 mils/yr.) while the pitting rate decreased (7.87 to 5.35 mils/yr.) at 279 and 672 days. Pitting depth is shown in Figure 4.3-3. Corrosion products were found to contain iron in carbon steel pipes and sulfide compounds in galvanized steel and copper pipes.

Bolholt - The uniform and pitting rates both increased very slightly with time. Scale consisted of zinc and silica in galvanized pipe and copper and sulfide compounds in copper pipe. No corrosion products were found in carbon steel pipes.

Mogilsa - Mogilsa is the only sulfide system with uniform and pitting rates similar to the oxygen systems. The other sulfide systems with similar high sulfide concentration (1.5 ppm) cause corrosion at lower rates. The difference may be due to the lower pH (7.9) at Mogilsa. Both the uniform and pitting rates decrease with time: the uniform rate from 1.6 mils/yr. at 294 days to 0.91 mils/yr. at 722 days, and the pitting rate from 20.1 (294 days) to 8.98 mils/yr. (722 days). At Mogilsa the pitting very nearly stops after 249 days. This is shown in Figure 4.3-3. Scale is iron and sulfide compounds in carbon steel pipes; zinc, silica, and sulfide compounds in galvanized pipe; and copper and sulfide compounds in copper pipes.

Hvammstangi - Uniform and pitting rates increased only slightly with time. Pitting depth is shown in Figure 4.3-3. Corrosion products are iron and silica in carbon steel pipes; zinc and silica in galvanized pipes; and copper and sulfide compounds in copper pipes.

Seltjarnarnes - This system has the lowest uniform corrosion and pitting rates of the sulfide and the oxygen systems. The uniform corrosion rate decreased from 0.02 to 0.01 mils/yr. for coupon sets pulled at 279 and 593 days, respectively. Pitting was virtually nonexistent. Scale analysis showed that incrustations were zinc, silica, and sulfide compounds in galvanized pipe and sulfide compounds in copper pipe. No corrosion products were found in carbon steel pipes.

Discussion of Oxygen- and Sulfide-Containing Sites

The results of this study indicate that both uniform corrosion and pitting of carbon steel are greater in oxygen-containing waters than in sulfide waters. For waters with the same oxygen concentration, the chance for corrosion increases with temperature. Oxygen may be present in the produced fluid or may be dissolved in the piped fluid due to atmospheric contamination through faulty system design. Limited testing (at Mogilsa) on high (1.5 ppm) sulfide fluids at a pH of 7.9 indicates that initial uniform corrosion and pitting rates are similar to oxygen-containing water. In most of the sulfide systems, the pitting rate decreases somewhat with length of exposure. The most pronounced example of this is the Mogilsa system (Figure 4.3-3). Pitting almost stopped at the end of the second year. Pitting rates for the oxygen systems remained nearly constant or decreased slightly (Figure 4.3-2), but pitting depths were greater than those for sulfide systems by a factor of approximately two.

Other compounds in the fluid also affect corrosion. Silica may act as an inhibitor, but at low concentrations may cause pitting. Chloride can also promote pitting. Increasing the pH of a fluid decreases the corrosion rate of carbon steel.

4.3.3 Operating Experience

The literature contains little information on how low-temperature fluids in the district heating systems are distributed and used. The exception is the Reykjavik District Heating System. Methods of fluid extraction from the wells and materials used in production and distribution systems, such as radiators and heat exchangers, are not reported. There are reports that carbon steel is widely used for main supply pipes, distribution pipes to users, and distribution pipes in buildings (Einarsson and Rislund 1978). Asbestos pipe has also been used for supply means, such as in the Husavik system (Kristinsson and Jónsson 1971).

In general, utilization of fluids for district heating includes the following components: (1) wells and collection piping, and, if required, a heat exchanger plant at the geothermal resource site; (2) transmission piping from the field to the utilization area; (3) a distribution system within the utilization area; (4) peak load installations; and (5) house connections (Einarsson 1975). Depending on the nature of the resource and elevation between wells and users, downhole well pumps and booster stations may or may not be required.

4.3.3.1 Reykjavik District Heating System

The Reykjavik District Heating System is the oldest system in existence in Iceland. The Reykjavik District Heating System uses water from several low temperature resources both outside and within the city

itself. Depending on whether water temperature is less or greater than 212°F, different methods of utilization are involved (Zöega 1974). Other low temperature heating systems can be expected to generally follow Reykjavik's utilization scheme.

In lower temperature areas (less than 212°F), the water is produced by natural pressure. Water is collected from the wells into a cistern and piped to pumps at a lower elevation. The water is then pumped to storage tanks in the city through a double 14-inch pipeline (Kristinsson and Jónsson 1971). From these tanks the water is pumped to pumping stations throughout the city. From the pumping stations it is piped to users. At this point, the temperature is about 176°F. After circulation through radiators, the water is disposed through the city drainage system.

Within the city itself, resource temperatures have been found to be greater than 212°F. Waters from these higher temperature areas are produced using surface-mounted, electrically-powered downhole pumps to prevent boiling. Nitrogen in the water can cause blockage in house systems at higher elevations. The nitrogen is removed by a deaerator where the water is allowed to boil slightly. From the deaerator the water is pumped to various district pumping stations for distribution through carbon steel pipe. In some sections of the city, water returning from houses is mixed with water from the higher temperature resources to maintain a suitable temperature for heating and domestic use (Zöega 1974). Disposal is through the city drainage system.

Various resources have been added to the Reykjavik District Heating System since 1930. The first water used was 189°F and located within the city. This resource caused no corrosion problems, but a protective scale of metal oxides, silica, and magnesia formed. In 1943, water from the Reykir area began to be used in the system, and serious corrosion occurred. This was due to the dissolved oxygen in the geothermal water (1 to 2.6 ppm). The higher concentration of oxygen was caused by (1) the use of air lifts in pumping, and (2) direct contact of water and air in the storage tanks.

Steel and cast iron severely corroded. The zinc coatings on galvanized steel were destroyed rapidly. Corrosion was controlled by adding sodium sulfite (10 ppm sodium sulfite per 1 ppm oxygen).

In 1948, 189°F water from the Reykjahlid area was mixed with the water supplying the Reykjavik system. The sulfide ion content in the Reykjahlid water eliminated most of the oxygen from the Reykir resource. A protective iron oxide-silica coating formed.

A third resource producing 266°F water was found in Reykjavik. This resource contained no oxygen, and its addition to the system did not cause corrosion problems. A thin magnetite coating did form on the iron.

A mixture of water from all three resources which contained 0.1 to 0.5 ppm oxygen caused little corrosion. A protective white coating, consisting mainly of iron oxide, silica, and magnesia, formed on the iron. Hermannsson (1970) discusses corrosion and scaling experience in the Reykjavik District Heating System using low temperature fluids.

4.3.3.2 Other District Heating Systems

Reports on operational experience from other district heating systems that use low temperature resources are limited. It is reported that carbon steel pipes in the Olafsfjordur system have lasted more than twenty years; however, ten radiators in the same system show corrosion rates similar to those of coupons (1.5 and 1.2 mils/yr.) (Hermannsson et al. 1975).

At Hrisey, oxygen was reduced to less than 0.01 ppm by adding 14 ppm of sodium sulfite. Corrosion was greatly reduced. A high sulfide concentration and a lower pH caused the perforation of thin-walled copper tubes in heat exchangers at Mogilsa. At Seltjarnarnes coupon tests showed no corrosion problem, but steel radiators failed due to pitting after two to five years of service. An increase of pH 8.5 to pH 9.2 reduced these failures. In sulfide-containing waters, a lifetime of ten to twenty years for thin-walled carbon steel radiators has been reported. Copper pipes carrying drinking water have lasted over twenty years in sulfide systems (Einarsson and Rislund 1978).

4.3.4 Other Low Resource Temperature Heating Systems in Iceland

4.3.4.1 Laugaland-Akureyri District Heating System

The Laugaland-Akureyri District Heating System presently has two producing wells at depths of 6300 and 4300 ft. The well water temperature is 203°F, and the flow rate is 1750 gal./min. Two pumps at a depth of 425 ft. pump the geothermal water into a 10,600 ft.³ degasser (see Figure 4.3-4). In the degasser, carbon dioxide is removed by natural pressure changes. Two pumps at Laugaland then pump (at 120 psia) the degassed water through a carbon steel pipe 7.5 miles to Akureyri. The flow rate is 1590 gal./min.

There are two storage tanks in Akureyri, a lower level tank at 230 ft. (see Figure 4.3-4, Hot Water Storage Tank for Nedra Veitusvaedi, a part of the city) and a higher level tank at 377 ft. (see Figure 4.3-4, Hot Water Storage Tank for Efra Veitusvaedi, also a part of Akureyri). The lower level tank receives the 203°F water from the Laugaland pump station. The temperature of the geothermal water in the lower tank is reduced to 176°F by mixing the water with recirculating, cooled water from the upper part of the city. The higher level tank, which services the upper part of

70-1532-2

FIGURE 4.3-4. SCHEMATIC OF THE LAUGALAND-AKUREYRI DISTRICT HEATING SYSTEM

Akureyri, receives the 176°F water from the lower tank. The Akureyri pump station transports the water to the 377 ft. high tank.

The distribution lines of the Laugaland-Akureyri District Heating System are carbon steel pipe. The pipe diameter is 19.7 inches, and its walls are 0.28 inches thick. Insulation is rock wool 2.4 inches thick and held around the pipe by aluminum sheeting.

The geothermal water from the Laugaland-Akureyri District is free of hydrogen sulfide; the oxygen concentration is 0.02 to 0.06 ppm. Oxygen is removed by sodium sulfite treatment of 18.3 lb. per day. (This rate of treatment is equal to a sodium sulfite-oxygen molar ratio of 2:1 when oxygen concentration is 0.06 ppm.) The sodium sulfite-oxygen reaction occurs in the 7.5-mile carbon steel line to Akureyri.

4.3.4.2 Heimaey, Vestmannaeyjar Heating District

A lava-tephra (black ash with particles about $\frac{1}{4}$ -inch) formation resulted from the 1973 volcanic eruption of Helgafill, Vestmannaeyjar, Iceland.

The heat extraction units consists of a rock pit and a heat exchanger chamber within the lava-tephra formation, and a chimney exiting the heat exchange chamber. Water is sprinkled on the formation's surface. As it percolates through the hot lava and ash, the water becomes steam. The rock pit, chamber, and chimney form a path of least resistance to the steam movement. Most of the steam condenses on the heat exchangers surfaces. It is recirculated to the surface of the ash.

Fresh water circulates inside the four heat exchangers in the chamber. The temperature of the circulating fresh water rises to about 185°F inside the heat exchangers. Each heat exchanger consists of 30 carbon steel tubes with a surface area of 388 ft.² per exchanger. The exterior of the heat exchangers is epoxy-coated to prevent corrosion. The lifetime of the heat exchangers is five years. The thermal energy produced by the four heat exchangers is equal to 0.8 MW.

The Heimaey system differs from others in Iceland because it uses a closed inner loop. Fresh water is brought from the mainland and is deaerated by heating to 203°F before it enters the inner loop of the heat exchangers. No water is removed from the inner loop. The heated fresh water circulates inside cast iron radiators for domestic space heating. A flowrate of 0.86 gal./min. is required to heat a 14,125-to-17,600 ft.³ house. Hot water for domestic use is generated in heat exchanger systems.

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4.4 BORACIFEROUS REGION (LARDERELLO, MONTE AMIATA, AND TRAVALE GEOTHERMAL FIELDS), ITALY

Electric generation using geothermal resources of the Boraciferous region of Italy began in 1904 at the Larderello geothermal field. A reciprocating noncondensing-type engine generated about 15 kW of electricity. However, all generating capacity was destroyed during World War II. Increased development at Larderello field and other fields, including Monte Amiata and Travale, has raised the current total geothermal electric generating capacity in Italy to 420 MW (see Table 4.4-1). These geothermal fields are located in the boraciferous region of Italy, shown in Figure 4.4-1.

The developed area of Larderello extends over about 45,700 acres with about 190 producing wells. The average well depth is 2152 ft.; those drilled since 1969 average 3704 ft. There are exceptionally high thermal gradients in the area, usually 16°F/100 ft. but as high as 55°F/100 ft. Temperature of the fluid may vary from 300°F to 500°F. Maximum flow rates normally range between 100,000 and 200,000 lbm/hr., although the rate of flow may exceed 600,000 lbm/hr in a few wells (DiPippo 1979).

The Larderello, Monte Amiata, and Travale resources are vapor-dominated and are utilized with the Rankine power cycle, which uses steam directly. The steam is produced at temperatures ranging from 285° to 430°F and at pressures of 29 to 102 psig (DiPippo 1979). Steam is transported from the individual wells to a number of relatively small capacity electric generating plants. At the Larderello plants, the steam passes through condensing turbines. Noncondensable gases are extracted by large capacity compressors and either discharged to the atmosphere or sent to chemical plants. The condensate is sent to a hot well and then pumped to natural draft cooling towers. In the Monte Amiata and Travale regions, the power plants discharge the expended steam into the atmosphere and do not utilize condensers. Table 4.4-1 lists power plants and their capacities (ENEL 1976).

4.4.1 Geothermal Fluid

The Larderello geothermal fluid is generally steam and gas. The gas content varies from one percent to 20 percent by weight. The production fluid compositions from several sites are given in Table 4.4-2. Tables 4.4-3 and 4.4-4 give compositions of steam condensate and compressor discharge gas. The data from certain plants are grouped into categories because their fluid properties are so similar. The term "residual gases" refers to the species methane, nitrogen, hydrogen, and oxygen. These are grouped since they are present in small quantities and, except for oxygen, do not seem to affect corrosion rates. Oxygen has not been encountered in the geothermal steam except as a contaminant in fluids which have been in contact with air.

TABLE 4.4-1. INSTALLED CAPACITY OF ITALIAN GEOTHERMAL ELECTRIC POWER PLANTS

POWER PLANT	NUMBER OF UNITS	CAPACITY (MW)	
		PER UNIT	TOTAL
Larderello 2	4	14.5	
	1	11.0	69.0
Larderello 3	3	26.0	
	1	24.0	
	2	9.0	120.0
Gabbro	1	15.0	15.0
Castelnuovo	1	26.0	
	2	11.0	
	1	2.0	50.0
Lago	1	14.5	
	1	12.5	
	1	6.5	33.5
Lagoni Rossi	1	3.5	
	1	3.0	6.5
Monterotondo	1	12.5	12.5
Sasso Pisano	2	3.5	
	1	12.5	
	1	3.2	19.2
Serrazzano	1	15.0	
	2	12.5	
	2	3.5	47.0
Bagnore	2	3.5	7.0
Piancastagnaio	1	15.0	15.0
Travale	1	3.0	
	1	15.0	18.0

Source: DiPippo 1979

FIGURE 4.4-1. LOCATION OF GEOTHERMAL RESOURCES IN BORACIFEROUS REGION OF ITALY

TABLE 4.4-2. STEAM COMPOSITIONS AT ITALIAN GEOTHERMAL SITES

STEAM CHARACTERISTICS	Larderello, Gabbro, Castelnuovo		Lago, Lagoni Rossi, Monterotondo		Sasso, Serrazzano		Bagnore, Piancastagnaio		Travale	
% Noncondensable gas (by weight)	4.4		3.0		3.5		20.0		9	
<u>Gas Analysis (% Vol)</u>										
Carbon dioxide (CO ₂)	95.50		89.20		89.90		94.69		93.50	
Hydrogen sulfide (H ₂ S)	1.80		4.01		4.08		0.80		1.40	
Residual gases ^a	2.70		6.79		6.02		4.51		5.10	
<u>Condensate Analysis</u>										
	<u>Min</u>	<u>Max</u>	<u>Min</u>	<u>Max</u>	<u>Min</u>	<u>Max</u>	<u>Min</u>	<u>Max</u>	<u>Min</u>	<u>Max</u>
pH	6.4	8	6.8	8	6.3	8.1	7.6	7.8	7.0	7.7
<u>ppm</u>										
TDS (@220°F)	50	200	35	270	140	220	50	160	100	160
Ammonium ion (NH ₄)	150	260	82	130	120	216	800	980	280	300
Boric acid (H ₃ BO ₃)	151	330	150	310	91	360	180	320	400	500
Sulfate (SO ₄ ²⁻)	trace	20	trace	70	trace	30	3	25	10	20
Chloride (Cl ⁻)	1	20	0.5	14	0.5	15	0.1	0.3	0.3	1
Silica (SiO ₂)	trace	20	trace	trace	trace	trace	0	0	trace	trace
Iron (Fe)	0.4	1	0.1	0.6	trace	0.4	0.2	0.9	0.2	0.3
Calcium (Ca)	0.5	1.5	0.5	2	0.2	0.5	0.15	0.35	0.5	1.0
Magnesium (Mg)	0	1	0.02	0.06	trace	0.2	0.01	0.02	0.05	0.10
Hydrogen sulfide (H ₂ S)	----	----	----	----	----	----	----	----	----	----
Arsenic (As)	0.02	0.12	0.007	0.24	0.05	0.15	0.003	0.014	0.05	0.20
Sodium (Na)	0.10	0.30	0.8	1	trace	0.06	0.15	0.9	0.2	0.3
Potassium (K)	0.05	0.15	0.7	1	trace	0.08	0.2	0.4	0.1	0.2

^aIncludes methane (CH₄), nitrogen (N₂), and hydrogen (H₂)
Source: Allegrini 1979

TABLE 4.4-3. COMPOSITION OF COOLING OR DISCHARGE WATER AT ITALIAN GEOTHERMAL SITES

FLUID CHARACTERISTICS		Larderello, Gabbro, Castelnuovo ^a		Lago, Monterotondo ^a		Sasso, Serrazzano ^a		Bagnore Piancastagnaio ^b		Travale ^b	
cm	Gas/Liter Water (at 760 mmHg, 0°C)	Min 70	Max 160	Min 40	Max 70	Min 60	Max 170	Min 90	Max 150	Min 20	Max 40
<u>Gas Analysis (% Vol)</u>											
	Carbon dioxide (CO ₂)	82.8	84.0	37.5	71.4	68.5	79.5	65.00	87.00	40.00	----
	Oxygen (O ₂)	0.18	0.28	0.4	0.5	0.4	0.8	0.14	0.60	0.70	----
	Hydrogen sulfide (H ₂ S)	0.11	0.15	0.1	1.1	0.07	0.1	0.07	0.10	trace	----
	Nitrogen (N ₂)	15.67	16.78	27.0	49.0	30.9	19.5	12.20	35.40	59.30	----
<u>Condensate Analysis</u>											
	pH	6.7	7.8	6.4	7.2	7.1	7.8	8.0	8.8	7.0	7.5
	ppm										
	TDS (@ 220°F)	500	800	300	600	600	1100	20	3000	4000	5000
	Ammonium ion (NH ₄ ⁺)	190	310	106	120	190	200	150	260	80	150
	Boric acid (H ₃ BO ₃)	440	750	270	500	550	850	200	2750	7000	7500
	Sulfate (SO ₄ ²⁻)	50	300	100	150	150	200	trace	20	trace	20
	Chloride (Cl ⁻)	1	3	1	75	0.9	7	trace	0.21	1.5	2.5
	Silica (SiO ₂)	trace	trace	trace	trace	trace	trace	0	trace	trace	trace
	Iron (Fe)	0.2	1	0.1	0.2	trace	trace	0.3	0.50	0.5	1.5
	Calcium (Ca)	2	4	1	2.5	0.2	2	0.2	3.00	0.05	2.00
	Magnesium (Mg)	0.2	0.5	0.1	0.2	trace	0.2	0.05	0.20	0.01	0.02
	Arsenic (As)	0.2	0.5	0.05	0.1	0.22	0.33	0.006	0.25	0.30	0.90
	Sodium (Na)	0.2	0.5	1	1.5	0.1	0.3	0.15	0.30	0.10	0.50
	Potassium (K)	0.2	0.6	0.05	0.3	0.1	0.2	0.15	0.30	0.09	0.10

^a Cooling water^b Discharge water

Source: Allegrini 1979

TABLE 4.4-4. COMPRESSOR DISCHARGE GAS COMPOSITION AT ITALIAN GEOTHERMAL SITES

COMPONENT	Larderello, Gabbro, Castelnuovo		Lago, Monterotondo		Sasso, Serrazzano	
	% Vol.	ppt ^b	% Vol.	ppt	% Vol.	ppt
Gas Analysis						
Carbon dioxide (CO ₂)	84.35	858.99	66.40	637.60	81.50	849.60
Hydrogen sulfide (H ₂ S)	1.13	9.05	2.55	20.10	2.20	18.40
Residual gases ^a	14.52	79.93	31.50	208.28	16.30	90.46
Moisture	0.010	51.99	0.08	133.99	0.007	40.60

^aIncludes methane (CH₄), nitrogen (N₂), and hydrogen (H₂)

^bppt = part per thousand

Source: Allegrini 1979

4.4.2 Component Analysis

4.4.2.1 Method

For materials performance studies at the Italian geothermal resources, analyses of components in actual use under certain environmental conditions were carried out. Coupons of various materials usually were not used, and there were no laboratory tests except for the tin-plated copper wire test exposed to the plant atmosphere. The materials or pieces of equipment discussed were chosen to illustrate the influence of the type of transported fluid on equipment service life. Investigations of electrical components from a hydrogen sulfide-containing plant atmosphere indicate the adverse effects of this species on material performance.

4.4.2.2 Results and Discussion

Service life is defined as the period of proper functioning with maintenance performed only at the times recommended by the manufacturer (Allegrini 1979). The time period for repeated extra maintenance before component replacement was not included.

The results of material and component analyses are shown in Tables 4.4-5 and 4.4-6. The data has been divided into two environmental categories: aerated steam condensate (Table 4.4-5) and industrial

TABLE 4.4-5. COMPONENT ANALYSES IN AERATED STEAM CONDENSATE^a

COMPONENT AND APPLICATION	MATERIAL CHARACTERISTICS	ENVIRONMENTAL CONDITIONS ^a	BEHAVIOR DURING OPERATION
Pipes for transport of condensate to and from coolers	Carbon steel UNI Aq.42-3544 ^b Thickness: 0.2-0.4 in. Diameter: 39.4 in.	Temperature: 77-115°F Pressure: 14.7-29.4 psig Fluid Velocity: 6.69-9.8 ft/sec. Complete chemical analysis in Table 4.4-3, columns 1, 2 and 3.	Satisfactory behavior ^c for about 10 years
Geothermal central barometric pipes to and from coolers	AISI 316 and 316 L Thickness: 0.2 in. Diameter: 11.8-39.4 in.	Temperature: 104-122°F Pressure: 1.4-14.7 psig Fluid Velocity: 3.3-9.8 ft/sec. Complete chemical analysis in Table 4.4-3, columns 1, 2 and 3	Satisfactory behavior ^c in the weldments. AISI 316 L is superior to 316. In operation since 1966.
Pipes and dividing sluices for transport of condensate for antifreeze installation, and distribution of cooling tower water	Peraluman 25 ^b (2.5% Mg) Peraluman 30 ^b (3.0% Mg) Peraluman 35 ^b (3.5% Mg)	Temperature: 77-113°F Pressure: 0.7 psig Complete chemical analysis in Table 4.4-3, columns 1, 2, and 3.	Fair behavior ^d for periods of about 10 years. There may be localized corrosion with wide pits. Scale of reliability as follows: 30<35<25. AISI 316 is better than these alloys. Aluminum 30 gave good results.
Strainer, nuts, and bolts used as filter for condensate leaving central geothermal coolers.	AISI 316 Diameter: 0.5 in.	Temperature: 77-95°F Pressure: 4.3 psig Fluid Velocity: 3.3-9.8 ft/sec. Complete chemical analysis in Table 4.4-3, columns 1, 2, and 3.	Satisfactory behavior ^c if the material is free of tensile stresses. Otherwise substantial stress corrosion cracking occurs within 12-14 months. Corrosion of general surface type, formation of pits, and 10-20% weight loss for nuts and bolts. Good behavior for strainer.
Fastening nuts and bolts for wooden droplet equipment in natural draft cooling towers	AISI 316	Temperature: 77-113°F Barometric pressure Complete chemical analysis in Table 4.4-3, columns 1, 2, and 3.	Satisfactory behavior ^c for about 15 years
Water proof paint covering concrete bottom of cooler basin of natural draft cooling tower	Based on bitumen and resin; reinforced with synthetic or mineral fibers	Temperature: 68-86°F Complete chemical analysis in Table 4.4-3, columns 1, 2, and 3.	Satisfactory behavior ^c for about 5 years

^aEnvironmental chemical analysis in Table 4.4-3.^bSee Table 4.4-7 for material composition.^cThe satisfactory service times refer to a period of proper functioning with maintenance of the equipment performed only at the times recommended by the construction firms. The times in which the materials underwent repeated extra maintenance before replacement were not included.^dNot defined.

SOURCE: Allegrini 1979

atmosphere (Table 4.4-6). Additional details on environmental conditions and material characteristics are also given in the two tables.

AISI 316 stainless steel components generally performed very well in most operating conditions involving condensate. Service lives are estimated to be about ten to fifteen years. However, a wire of the same material placed in a geothermal steam line failed after 40 days. Stress

TABLE 4.4-6. COMPONENT ANALYSES FROM INDUSTRIAL ATMOSPHERE^a

COMPONENT AND APPLICATIONS	MATERIAL CHARACTERISTICS	ENVIRONMENTAL CONDITIONS	BEHAVIOR DURING OPERATION
Paint for concrete surfaces	Based on unsaponifiable resins and organic synthetic fibers	Possibility of leaching by condensate	Satisfactory behavior ^b for at least 5 years. Care must be taken that cement is perfectly dry before application. Foundation should be 0.08 oz/ft ² ; paint should be 3.3 oz/ft ² .
Nuts and bolts used in supporting structures	Carbon steel UNI 3740-44 ^c Yield strength: 142-177 ksi Galvanized by immersion: 0.3-0.6 mil	Temperature: 23-104°F Pressure: barometric	Not suitable for more than 8-12 months. Excessive corrosion rates after that time. However, protection with an oil phenol-glycerphthalic paint cycle ^d increases useful period to at least 4 years. Paint thickness about 7.9 mil minimum.
Flame galvanized brackets and frame work of the electrical lines	Carbon steel sandblasted to Swedish SA 2.5-SA3 then flame galvanized with oxyacetylene. Covered with paint based on phenolic oil and passivating pigments. Thickness: 5.9 mil	Temperature: 23-104°F Pressure: barometric	Satisfactory results ^b . Average life about 5 years.
Aerial electric line support cable	Galvanized carbon steel cable - sec. 28 x 10.7 mm		Satisfactory behavior ^b for up to 8 months of operation. Use after that not advisable.
Alloy wire for electrical lines	Aldray ^c alloy wire, sec. 60 x 25 mm		Satisfactory results ^b for 10-15 years; outside of the industrial atmosphere, 25-30 years. Life for terminal board is shorter. Differential aeration corrosion is evident on wire. Terminal board is in good condition if nuts and bolts are made of AISI 316 or board has pressed terminals.
Aerial electrical lines	Seven-strand copper wire with sec. 35 x 16 mm without external protection		Unsatisfactory results in 8 months of testing, with deterioration of the mechanical properties and weight loss due to hydrogen sulfide attack.
Aerial electrical lines	Tin-plated copper wire, sec. 25 x 6 mm coated with butyl rubber 0.06 in. thick	Temperature: 23-104°F Pressure: barometric This is an industrial atmosphere reconstructed in the laboratory	Satisfactory behavior ^b in tests corresponding to 8 months of operation. Longer time periods not advisable. These are results of laboratory tests. No experiments were run on the installations.

^a Contains condensation drops and H₂S

^b The satisfactory service times refer to a period of proper functioning with maintenance of the equipment performed only at the times recommended by the construction firms. The times in which the materials underwent repeated extra maintenance before replacement were not included.

^c See Table 4.4-7 for material composition

^d The protective paint cycle is discussed in Section 4.4.3.1.

Source: Allegrini 1979

corrosion cracking (SCC) due to a high chloride concentration caused the failure.

Another instance of SCC was the deterioration of the strainer used as a filter for the condensate leaving the geothermal coolers. When under tensile stress, the AISI 316 stainless steel underwent extensive stress corrosion cracking within 12 to 14 months.

A series of aluminum-based alloys were tested as materials for piping and dividing sluices for condensate transport. Fair behavior (not defined) was observed with Peralumans 25, 30, and 35. Pitting and uniform corrosion did not occur. AISI 316 was found to be far superior to the aluminum alloys (Allegrini 1979).

Analyses of components used in an industrial atmosphere (Table 4.4-6) indicate that materials unprotected by a coating of paint (described in Section 4.4.3.1) corroded excessively after eight months of operation. When painted correctly, service life increased to five years.

Results of analyses also point out the superiority of Aldray (0.35Fe-0.6Si-0.4Mg) alloy wire for use as electrical lines. No other wire tested, including those which were galvanized or coated with butyl rubber, performed satisfactorily for longer than eight months. Aldray wire has a usable life of ten to 15 years in the industrial atmosphere and 25 to 30 years outside this environment.

The compositions of the alloys referred to by Italian code (UNI) in Tables 4.4-5 and 4.4-6 and in the tables in the following section are presented in Table 4.4-7. The equivalent ASTM designations and hardness and yield strength data are included.

4.4.3 Operating Experience

There are two types of power plants in the Larderello, Monte Amiata, and Travale regions: noncondensing and condensing. Figure 4.4-2 is a diagram of a noncondensing unit that has been converted into a condensing unit. This type of system is utilized at many of the Italian power plants.

4.4.3.1 Wellhead and Steam Conduction System

The steel in the wellhead is capable of resisting high temperatures and flow rates (285°F to 430°F, 100,000 lbm/hr to 200,000 lbm/hr) and abrasion by particulates in the fluid. It is reinforced with tungsten carbide at heavy-duty points. A diameter of 13-3/4 inches has been established as the most suitable casing size for optimum flow conditions. Drilling for steam requires greater dimensions than those for other types of exploration because of high flow rates and relatively low fluid pressures.

TABLE 4.4-7. COMPOSITIONS OF MATERIALS USED IN ITALIAN GEOTHERMAL RESOURCES

CODE	EQUIVALENT DESIGNATION	COMPOSITION (Wt. %)	HARDNESS	YIELD STRENGTH (ksi)
UNI X10C13		12-14 Cr, 0.5 Ni, 0.3-0.5 Mn, 0.8-0.14 C, 0.3 Si		35.6
UNI 6901 (INOX X14 CN19)		18-20 Cr, 1.5-2.5 Ni, 1.0 Mn (max), 0.04 P (max), 0.03 S (max), 0.16 C, 1.0 Si	HRB 250	71.1
UNI Fe 52	ASTM A-252			
UNI 3740-44		0.9-1.2 Cr, 0.8-1.1 Mn, 0.035 P (max), 0.035 S (max), 0.35 C, 0.40 Si		91.0
UNI Aq 37	ASTM A53			
UNI Aq 42	ASTM A53			
UNI Aq 45	ASTM A53			
<u>DEWA Metals</u>	Lead- or tin-based alloys			
MB0		10 Sn, 15.5 Sb, 1 Cu, 73.5 Pb	BHN 27	
MB010		19 Sb, 1 Cu, 1 As, 79 Pb	BHN 20	
MB80		80 Sn, 12 Sb, 6 Cu, 2 Pb	BHN 30	
MB8F		80 Sn, 11 Sb, 9 Cu	BHN 33	
<u>Aluminum Base</u>				
Ald-ray		0.35 Fe, 0.6 Si, 0.40 Mg	BHN 68-72	
Aluman 30 UNI 356B		0.10 Cu, 0.5 Fe, 0.5 Si, 0.2 Mg, 1-1.5 Mn, 0.15 Zn	BHN 30-55	
Peraluman 25		0.1 Cu (max), 0.45 Fe (max), 0.45 Si (max), 0.1 Mn (max), 2.2-2.3 Mg, 0.15-0.35 Cr, 0.1 Zn (max), 0.15 impurities	BHN 45-85	11.4-39.8
Peraluman 35		0.05 Cu, 0.4 Fe, 0.3 Si, 0.2-0.4 Mn, 3.2-3.8 Mg, 0.1 Zn (max), 0.1 Ti (max), 0.01 Ni (max), 0.2 impurities	BHN 55-100	12.8-44.1

SOURCE: Allegrini 1980

BACK-PRESSURE OPERATION

239 t/h - 8 ata - 410°F - 30% GAS
208 t/h - 11 ata - 419°F - 30% GAS

CONDENSATION OPERATION

133 t/h - 5 ata - 400°F - 8% GAS
118 t/h - 8 ata - 410°F - 8% GAS
112 t/h - 11 ata - 419°F - 8% GAS

FIGURE 4.4-2. SCHEMATIC OF ITALIAN BACK PRESSURE (ATMOSPHERIC DISCHARGE) PLANT CONVERTED TO CONDENSING PLANT. CAPACITY IS 15 MW(e) NET (Allegrini 1979)

Numerous drill string failures have occurred in Italian geothermal wells at depths greater than 9800 feet. One cracked drill pin was sent to Radian Corporation for failure analysis. Temperature measurements were being taken inside the drill pipe when failure occurred. The drill pipe was used for instrument protection. It had been put down the 13,124-foot deep Sasso 22 well about 80 hours prior to taking measurements. The temperature was 716°F at the bottom of the well and 203°F at liquid level. The depth where failure occurred was not reported (Anliker 1980).

The drill pin was made of 38 NC D4 steel (AISI 9840) with an average hardness of Rockwell C 35.2. Metallographic examination showed the needle-like pattern typical of a high strength, low alloy, heat-treated steel. The fracture surface displayed a distinct intergranular failure mode which changed to microvoid coalescence, or dimple formation, near the outside surface. Analysis of the scale by the energy dispersive x-ray technique indicated iron, sulfur, calcium, silicon, and chromium. Compound analysis by x-ray spectroscopy identified chromium and iron oxides, calcium iron silicate, and iron sulfide.

It was concluded that the drill pin failed by SSC (Anliker 1980). This type of failure is typical of high strength steels placed in the hydrogen sulfide environment (540 ppm) of this geothermal well. The iron sulfide is the product of the corrosion reaction of steel with hydrogen sulfide. The other compounds present in the scale are the result of oxidation after the failure.

Support Framework Painting Cycle

The steam pipeline support framework is ASTM A53 carbon steel or a similar material. When coated with a tar- and tar oil-based paint, the life expectancy of the framework is 30 years. Without the paint, service period is greatly reduced because of corrosive condensation and hydrogen sulfide in the industrial atmosphere. The protective painting cycle consists of:

- A. Sand-blasting according to the Swedish Standards Grade SA 2.5 to 3 (U.S. Equivalent SSPC 5 to SSPC 10, or NACE No. 1 to NACE No. 2).
- B. Application of flame-sprayed metallic zinc (METCO Method) to a thickness of 2.4 to 3.1 mils.
- C. Application of a phenolic oil resin-based paint containing oil and zinc chromate to a thickness of 3.1 mils.
- D. Application of an intermediate coat of phenolic oil and passivating pigments to a thickness of 2.4 mils.

- E. Application of a final phenolic oil and modified glycerophthalic coat that is free of lead pigments and other heavy metals that might react with hydrogen sulfide. Thickness should be 2.4 mils.

Treating and painting the protected structures enables satisfactory service without extra maintenance and touch-ups for approximately five years. If it is not possible to use flame-sprayed zinc, a galvanizing organic paint, such as an epoxy type with a high zinc content, should be applied to a thickness of 2.4 mils. Polyurethane-type paints should not be used. The treatment cycle should begin at step C if old deteriorated paint or iron oxide is present on the material surfaces (Allegrini 1979).

Steam Pipe

The steam pipe is made of weldable carbon steel, API standards 5LX grade X52 and/or ASTM A-252. The pipes' wall thicknesses are 0.24 to 0.31 inch and diameters are 10, 14, 18, 26, and 32 inches. The steam pipe walls are also insulated with asbestos fiber 1.2 to 4.7 inches thick.

The service period of a steam pipe depends on the nature of the geothermal fluid transported and can vary from 10,000 to 120,000 working hours. When the chloride ion content exceeds 10 ppm, the operation times decrease drastically. The average life-span of the pipe at Larderello is about 40,000 hours when chloride ion concentration is 10 ppm to 35 ppm. If the chloride ion content exceeds 35 ppm to 40 ppm, life span decreases to 10,000 to 15,000 hours. In particular, corrosive phenomena, such as stress corrosion cracking, are more severe in the presence of condensation.

It should be noted that a test specimen holder made of AISI 316 (diameter 0.4 in) failed after 40 days of operation when placed in a steam line. The geothermal steam composition is given in Table 4.4-8. The temperature is 392°F, the pressure 29.4 psig, and the velocity 98 to 131 ft/sec. Fissuring and subsequent rapid destruction of the material was primarily caused by SCC. The high chloride ion concentration (40 ppm) caused the SCC.

Control Valves

The service period between overhauls for control valves ranges from 10,000 to 80,000 hours of operation. For the material characteristics of each component in the valves, see Table 4.4-9.

Chemical (electroless) nickel plating (Kanigen process) produced negative results when the valve was exposed to condensation. The period for testing nickel plating was 231 days of operation. The valve was perforated in the lower part of the seat. However, perforations were not seen in valves of the ASA series after an equal test period.

TABLE 4.4-8. CHEMICAL ANALYSIS OF GEOTHERMAL STEAM^a
WELL VC-3 (LARDERELLO)

COMPONENT		CONCENTRATION
<u>Gas Analysis (% Vol)</u>		
Carbon dioxide	(CO ₂)	98.14
Hydrogen sulfide	(H ₂ S)	3.45
Residual Gas	^b	7.41
<u>Condensate Analysis</u>		
pH		6.4
TDS (@ 220°F)		<u>ppm</u> 420
Ammonium ion	(NH ₄ ⁺)	75.1
Boric acid	(H ₃ BO ₃)	517.2
Sulfate	(SO ₄)	19.1
Chloride	(Cl ⁻)	40.0
Silica	(SiO ₂)	trace
Iron	(Fe)	trace
Calcium	(Ca)	2.2
Magnesium	(Mg)	1.05
Hydrogen sulfide	(H ₂ S)	18.15
Arsenic	(As)	0.185
Sodium	(Na)	none
Potassium	(K)	none

^a% noncondensable gas (by weight): 4.0

^bIncludes methane (CH₄), nitrogen (N₂), hydrogen (H₂)

SOURCE: Allegrini 1979

TABLE 4.4-9. CONTROL VALVE COMPONENT MATERIALS

COMPONENT	MATERIAL CHARACTERISTICS
Body	Steel fused to carbon ASTM - A216 WCS
Packing	ASA 150 - asbestos ASA 300 - asbestos ASA 600 - asbestos
Cover	Welded carbon steel ASTM - A216 WCS
Cover gasket	Sintrex 300 (asbestos)
Support	Steel welded to carbon ASTM - A216 WCS
Threaded bolts	ASTM - A193 - B7
Wedge guide	Stainless steel ASTM-A 182 F6 with Stellite No. 6 facing
Gate	Forged or weldable carbon steel with electrowelded facing or coating of AISI 304L and Stellite No. 6
Shaft	Stainless steel ASTM - A182 F6
Packing box	Aluminum bronze ASTM - B148-9A
Packing flange	UNI Aq 45 ^a
Threaded ferrule	Aluminum bronze ASTM - B148-9A
Brace nuts	ASTM - A193 - B7
Bolts	ASTM - A194 - 2M
Retaining rings	ARMCO steel

^aSee Table 4.4-7 for alloy compositions.

Source: Allegrini 1979

Comparative tests between the ASA and UNI valves generally indicate better performance with the ASA valves. The gate was the most corroded part of the valve, especially at the exit for the geothermal fluid. Stellite facings have been corroded away in some cases.

Safety Valves

Safety valves had a stainless steel body and seats of AISI 304 covered with Stellite No. 6. The shaft was stainless steel, and the spring was made of Monel (unspecified grade) or stainless steel. The type of stainless steel used for these purposes was not specified. The service life before overhaul of the valve and replacement of the protection bellows spring was 6000 operating hours.

Expansion Joints

Service life of expansion joints varies from 20,000 to 50,000 hours of operation, depending on the fluid. The multilamellar expansion compensators are made of AISI 316. The two internal rakes in contact with the steam are made of one of the following materials: AISI 316L, Monel 400, Inconel 600, nickel, and Hastelloy B. The type of joint determines the metal used. Previous experiments with compensators made with AISI 316 rakes gave poor results. After operating two to six months, pitting and stress corrosion cracking occurred. Compensators made with carbon steel blades 0.16 to 0.3 inch thick operated five to eight years. In noncorrosive fluids, the service period increased to fifteen years.

Thermal Insulation

Thermal coating was rock wool in preformed crucibles at a density of at least 9.4 lbm/ft³. Density was critical because at densities less than 9.4 lbm/ft³, breakdown by vibration may occur. Thickness varied from 2.4 to 3.1 inches, and maximum inorganic finishing was ten percent. The coefficient of heat transfer from the rock wool was less than 0.03 Btu/hr-ft-°F at an average temperature of 302°F.

The first lining was rock wool held in place by galvanized iron wire (diameter 0.04 in) and then covered by spirally-wound polyethylene film (thickness 3.9 mil). The protective external covering was 99.5 percent aluminum with raised-edge lamination, 0.03 to 0.04 inch thick. Self-threading stainless steel (18-8) screws were used to close the outer coat. The life of the coating material was 200,000 operating hours.

Vapor Filters

The filter body was made of weldable carbon steel, equivalent to ASTM A-252, and the filtering cartridge was made of ASTM A-252 or AISI 316. Filter thickness corresponded to the type of fluid to be filtered. The

filter diameter was 0.2 to 0.3 inch. Service life of the filters in geothermal steam was 10 to 20 years with maintenance every two years.

Counterweight Valve

The counterweight valve consisted of a cast iron or carbon steel body, steel seats with AISI 304 facings, and a shaft of AISI 316. Time before overhaul was approximately 9000 hours. However, after about 800 hours of operation, this type of valve leaked steam from between the seat and the body of the valve, and efficiency decreased.

Muffler

The muffler was composed of an ASTM A53 shell and a cartridge made of AISI 316 or ASTM A252, depending on fluid characteristics. Rock wool in panels was used as the sound-absorbing material. Service period without overhaul was 40,000 to 80,000 hours.

Orifice Meter

The orifice meter was made of ASTM A-252-equivalent steel. It was coated on the measuring angle by electrodeposited AISI 316. The life expectancy was 120,000 to 160,000 operating hours.

4.4.3.2 Gas Extractor

There is a large amount of noncondensable gas in the Larderello geothermal fluid. This factor necessitates the use of high-capacity turbo-compressors to extract the gases from the condenser. The extracted gases are discharged to the atmosphere or sent to chemical plants (see Table 4.4-4 for gas composition). The gas extractor is coaxial with the turbine-generator unit.

Table 4.4-10 lists operation behavior for several components of the compressor. The performance of chosen compressor materials was satisfactory. At the inlet and outlet, however, AISI 316 was found to be inferior to lead-coated carbon steel, which had twice the normal operation lifetime.

Raschig rings used as a filler in the gas cooler were also tested in an environment consisting of steam and gas countercurrent with cold condensate. The chemical analysis of the gas is given in Table 4.4-4 (86°F to 104°F, 9.3 psig). AISI 316 rings have given satisfactory behavior since 1976. Ceramic rings of the same dimensions were too brittle, and those of carbon steel or AISI Series 400 corroded excessively. As can be seen from Table 4.4-10, AISI 316 components also performed well in other parts of the gas cooler.

TABLE 4.4-10. COMPRESSOR COMPONENT OPERATION BEHAVIOR^{a,b}

PRINCIPAL COMPONENTS	CONSTRUCTION CHARACTERISTICS	NORMAL	
		SERVICE LIFE	COMMENTS
Housing - Top and Bottom	Meehanite cast iron	10 yrs	Uncertain for 20 yrs
Diffusers	Meehanite cast iron	15 yrs	
Rotor	Carbon steel	15 yrs	
Shaft	Carbon steel	15 yrs	
Impellers	AISI 431	20 yrs	
Protective sleeves on shaft	AISI 431	10 yrs	
Base plate	Carbon steel	10 yrs	
Reduction gears			
Housing	Meehanite cast iron	20 yrs	
Slow wheel	Carbon steel	20 yrs	
Rapid pinion	ASTM - A519	20 yrs	
Cooler housing	Carbon steel tinned and lead-coated	20 yrs	
Pipes to compressors	AISI 316 and lead coated sheet	10 yrs	
Raschig rings	AISI 316	20 yrs	Maintenance (washing) needed every 5 yrs After this period of operation, the ceramic rings should be replaced due to deterioration.
Inlet/outlet	AISI 316	5 yrs	
	Lead coated carbon steel	10 yrs	Good results with rubber (ebonite)-lined pipe at less than 104°F

^aPlant Locations: Larderello 2, Larderello 3, Serrazzano, Castelnuovo, Gabbro, Lago, Monterotondo

^bEnvironment: Gas-vapor mixture; chemical analysis in Table 4.4-4.

Source: Allegrini 1979

4.4.3.3 Turbines and Condensers

There are both condensing and noncondensing power plants in Italy. The newer plants were built as condensing units; other condensing units were converted noncondensing units (See Figure 4.4-2). The remaining noncondensing units are the power stations in the Monte Amiata and Travale regions. The high pressure turbines in these plants are designed to be coupled to a low-pressure section and a gas extractor for possible conversion to condensation-cycle generation.

The noncondensing units are simple and reliable. Use of remote unit control from pilot power stations minimizes operating costs. These units are technically and economically advantageous when used with steam containing more than 15 to 20 percent by weight noncondensable gases. The specific fluid consumption is about 44.1 lbm per kw net under average conditions (70.5 psig, 356°F, five percent by weight gas content).

The average specific fluid consumption of a condensing unit is 17.6 lbm per kwh net at 118 psig, 410°F and eight percent by weight noncondensable gases.

Operation behavior of the turbine-condensor components, given in Tables 4.4-11, 4.4-12, and 4.4-13, indicates that the most important problem areas are the blades and the high pressure equipment. Corrosion in the turbine occurred principally in the crevice between the fixed blade material and the base material. INOX stainless steel (19 Cr-2Ni) was used for both the fixed and moving blades in the 26, 14, and 12.5 MW turbines. The service life was only five years. It was suggested that blades of a more resistant material be mounted at points where there is formation of condensate and areas of greatest corrosion (Allegrini 1979).

More resistant materials were used for the 15 MW turbines. Carbon steel-clad with AISI 316 was used for the fixed blades, and a 19Cr-2Ni stainless steel was used for the moving blades. Substituting the fixed blade material with AISI 316-clad carbon steel increased the lifetimes of both the fixed and the moving blades to ten years.

Another problem was the short life expectancies of the high pressure cylinder and wheels (see Table 4.4-13). Facing the cylinder and wheel materials with electrowelded AISI 316 prevented corrosion and gave much longer service.

The condensate pipes are made of welded sheet steel. The service life of these pipes has been extended to five to ten years by coating them internally with epoxy paint. For large diameter pipes (39 to 59 inches), excellent results have been obtained by cladding the internal surface with sheets of welded AISI 316.

TABLE 4.4-11. 26-MW TURBINE COMPONENT OPERATION BEHAVIOR AT LARDERELLO 3
AND CASTELNUOVO^a

PRINCIPAL COMPONENTS	CONSTRUCTION CHARACTERISTICS	NORMAL SERVICE LIFE	COMMENTS
Housing	Meehanite cast iron	10 yrs.	Uncertain for 20 yrs
Blade wheels	Ni-Cr-Mo steel ^c	10 yrs	Replace at 20 yrs
Fixed blades ^b	INOX stainless steel ^d (19 Cr-2 Ni)	5 yrs	Replace at 10 yrs
Moving blades ^b	INOX stainless steel ^d (19 Cr-2 Ni)	5 yrs	Replace at 10 yrs
Rotating labyrinths	300 series stainless steel applied to carbon steel sleeves	20 yrs	
Fixed labyrinths	Centrifuged cast iron applied to cast iron shells	15 yrs	
Automatic vapor uptake valves			
body	Carbon steel	20 yrs	
seat	AISI 316	5 yrs	
stem	Nitrided steel	5 yrs	
Auxiliary mixture condensers	Very thick cast iron lead- coated steel	20 yrs	Condensate analysis Table 4.4-3, column 1
Condensate pipes	Welded sheet internally painted with epoxy resin	5 yrs	Condensate analysis Table 4.4-3, column 1. Coating failed after 5 years
Spray nozzles	G-26 cast iron	5 yrs	Replace at 5 yrs

^aEnvironment: Geothermal steam; chemical analysis Table 4.4-2, column 1

^bThe blades of the turbine are all made of the same material, whatever the series. It may be advisable to mount blades of a more suitable material at the points where there is formation of condensation and areas of most corrosion.

^cComposition not given

^dSee Table 4.4-7.

Source: Allegrini 1979

TABLE 4.4-12. 12.5- AND 14-MW TURBINE COMPONENT OPERATION BEHAVIOR AT LARDERELLO 2, SERRAZZANO, LAGO, SASSO PISANO, MONTEROTONDO, CASTELNUOVO^a

PRINCIPAL COMPONENTS	CONSTRUCTION CHARACTERISTICS	NORMAL SERVICE LIFE	COMMENTS
Housing	Meehanite cast iron	10 yrs	Uncertain for 20 yrs
Blade wheels	Cr-Ni-Mo steel ^c	10 yrs	Replace at 20 yrs
Fixed blades ^b	INOX stainless steel ^d (19 Cr-2 Ni)	5 yrs	Replace at 10 yrs
Rotating blades ^b	Same material	5 yrs	Replace at 10 yrs
Rotating labyrinth	300 series stainless steel applied to carbon steel sleeves	20 yrs	
Fixed labyrinth	Centrifuged cast iron applied to cast steel shells	15 yrs	
Automatic pressure valve			
Body	Cast steel	20 yrs	
Seat	AISI 316	5 yrs	
Stem	Nitrided steel	5 yrs	
Auxiliary condensers	Very thick cast iron lead-coated steel	20 yrs	
Condensate pipes	Welded sheet steel internally painted with epoxy resin	5 yrs	Coating failed after 5 years.
Spray nozzles	G-26 cast iron	5 yrs	

^aEnvironments: Geothermal Steam; Table 4.4-2, columns 1, 2, 3

Condensate; Chemical analysis, Tables 4.4-3, columns 1, 2, 3

^bThe blades of the turbine are all made of the same material, whatever the series. It may be advisable to mount blades of a more suitable material at the points where there is formation of condensation and areas of most corrosion.

^cComposition not given

^dSee Table 4.4-7

Source: Allegrini 1979

TABLE 4.4-13. 15-MW TURBINE COMPONENT OPERATION BEHAVIOR AT GABBRO,
SERRAZZANO, TRAVALE, PIANCASTAGNAIO^{a,b}

PRINCIPAL COMPONENTS	CONSTRUCTION CHARACTERISTICS	NORMAL SERVICE LIFE	COMMENTS
High pressure cylinder	Weldable carbon steel	3 yrs	Uncertain for 10 yrs at Gabbro and Serrazzano. The corrosion phenomena that lead to such short operation times were corrected by a facing of electrowelded AISI 316
High pressure wheels	ASTM-0920	5 yrs	
Low pressure cylinder	Meehanite cast iron	10 yrs	The corrosion occurs principally between the final point of the blade material and the beginning of the base material
Low pressure wheels	ASTM-0920	10 yrs	
Fixed casing with blades	Carbon steel clad with AISI 316	10 yrs	
Blades	Stainless steel (15 Cr-2 Ni or 13 Cr-0.5 Ni)	10 yrs	
Rotating labyrinths	300 series stainless steel applied to carbon steel sleeves	20 yrs	Maintenance required every 2-3 yrs. Painting is done with: a) Bitumen derivatives (experimental) b) Synthetic resins (10 yr operation) The possibility of internally cladding the pipes of large diameters (39 to 59 in.) with sheets of welded AISI 316 has been tried with excellent results.
Fixed labyrinths	Centrifuged cast iron applied to cast steel shells	15 yrs	
Vapor uptake valves			
Body	Cast carbon steel	20 yrs	
Seat	AISI 316	5 yrs	
Stem	Nitrided steel	5 yrs	
Condenser housing	Lead-coated sheet steel	20 yrs	
Condensate pipes	Welded sheet steel painted internally with epoxy paint	10 yrs	
Spray nozzles	G 26 cast iron	5 yrs	
			Nozzles made of synthetic material (polymer concrete) are presently being tested

^aGabbro and Serrazzano are condensing units, Piancastagnaio and Travale are noncondensing units

^bEnvironment: Geothermal steam; Table 4.4-2, columns 1, 3, 4, 5
Condensate; Table 4.4-3, columns 1, 3

Source: Allegrini 1979

The case iron spray nozzles in all the condensers must be replaced every five years. However, nozzles made of synthetic polymer concrete are being tested in order to increase the service life.

4.4.3.4 Cooling Water System

The cooling system at the condensing power stations includes three stages of intermediate cooling. The first is part of the turbine-condenser unit, and the other two are in conjunction with the gas extractors. The cooling water and condensate are sent to a hot well, and then pumped at a rate of 24,000 to 35,000 gpm to the natural draft cooling towers.

Table 4.4-14 contains operation behavior for the components of the submerged pumps used to extract condensate from the condensers. The service life given for the fixed bearing coating is short when made of either hard rubber (2 years) or of DEWA metal (3 years). The fixed and rotary blades are made of different materials. The fixed blades are cast iron and have lasted 10 years; however, the rotating blades, made of a nonspecified grade of stainless steel, have lasted only four years. The cooling towers at Larderello are reinforced concrete. Portland cements and calcareous-type aggregates are rapidly destroyed by cooling water and steam condensate. Pozzolan and slag cements with siliceous aggregates performed much better and attack decreases with time. Adequate curing time is essential for good results. The Italian practices with regard to cements are discussed in more detail in Section 5.

4.4.3.5 Electrical System

The Larderello industrial atmosphere contains hydrogen sulfide and drops of condensate, both of which cause major corrosion of steel, copper, and their alloys. Because of this corrosion, much attention was given to the materials in the electrical system. The following components required special treatment:

1. Terminal boxes: The contacts should be protected with thick cadmium or nickel coatings.
2. Connectors for circuit boards: All electronic circuit connectors should be gold-plated.
3. Electrical circuits cards: The printed circuits must be protected with nickel, tin, or preferably, gold plating.
4. Relays: Relays should either be sealed in an inert atmosphere or should have gold-plated contacts. The treatment depends on the currents to be transmitted and interrupted.

TABLE 4.4-14. CONDENSATE EXTRACTOR COMPONENT OPERATION BEHAVIOR AT LARDERELLO 3,
CASTELNUOVO, LAGO, SERRAZZANO, GABBRO, MONTEROTONDO^a

PRINCIPAL COMPONENTS	CONSTRUCTION CHARACTERISTICS	NORMAL SERVICE LIFE	COMMENTS
Body	Cast iron	15 yrs	Corrosion is limited if the body of the pump is painted every 2 years with Teflon-based paint or liquid plastic cement (modified epoxy resins)
Shaft	Chrome-plated carbon steel	10 yrs	
Rotating sleeves (bearings)	Chrome stainless steel ^b	5 yrs	
Fixed bearing			
External casing	Carbon steel	20 yrs	
Coating	Hard rubber	2 yrs	
	DEWA metal ^c	3 yrs	
Fixed blades	Cast iron	10 yrs	
Rings to protect blades	Ferritic stainless steel ^b	5 yrs	
Rotating blade holder	Ni-Cr-Mo stainless steel ^b	25 yrs	
Rotating blades	Stainless steel ^b	4 yrs	Period during which one or more blades had to be replaced because of pitting
Nuts and bolts	AISI 316	10 yrs	

^aEnvironment: cooling water/condensate, Table 4.4-3, columns 1, 2, 3

^bComposition not given

^cSee Table 4.4-7

Source: Allegrini 1979

5. Weak circuit interruptors: All contacts of this apparatus, which includes selector or push-button switches, must be plated with nickel, chrome, or gold.
6. Indicating instruments: Digital readouts give the best results over time. They are extremely stable for their precision class because they have no mechanical moving parts.

The use of silver and its alloys in all parts of the electrical equipment is strongly discouraged (Allegrini 1979). The only case in which the use of silver is acceptable is in the contacts of the medium voltage interruptors. The high contact pressures and high currents which circulate in the contacts (400 to 3000 amps) have a self-cleaning effect during operation. Also, the substantial thicknesses of these contacts contribute to economically acceptable service lives.

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4.5 HATCHOBARU, JAPAN

Wells 2400 to 5250 feet deep tap a neutral chloride liquid-dominated resource at Hatchobaru on the island of Kyushu, Japan. The reservoir temperature is about 480°F based on silica geothermometer calculations.

The Hatchobaru Power Station, shown in Figure 4.5-1, is an advanced design dual flash power plant. Each well discharges total (two phase) flow into a single pipeline which is joined to other pipelines for transmission of the two-phase fluid to the powerhouse. There the phases are separated.

Primary steam is fed to the turbine from vertical cyclone separators. The liquid fraction is flashed in a horizontal flasher to produce low pressure secondary steam.

The turbine is a dual admission unit which receives primary steam at 83.2 psig and 327°F and secondary steam at 14.4 psia and 216°F. Exhaust pressure is 1.4 psia. Steam is condensed by a jet condenser. Noncondensable gases are extracted by a combination steam ejector/radial blower (DiPippo 1979).

The plant was commissioned in June 1977 and was delivering about 24 MW as of October 1978. It is expected that enough wells will be completed by spring of 1979 to allow the plant to reach full capacity (DiPippo 1979).

4.5.1 Fluid Chemistry

The fluid at Hatchobaru is a neutral chloride water. The pH of separated water reportedly varies from 3.4 to 8.4 as shown in Table 4.5-1. The fluid contains 4200 to 5600 ppm total dissolved solids of which 840 to 1340 ppm are chloride ions (Yamasaki 1978).

Separated steam contains about 0.301 percent by weight noncondensable gases (Mitsubishi 1979). The range of composition of these gases is given in Table 4.5-2.

Only one analysis of steam condensate is available from Hatchobaru (Mitsubishi 1979). Incomplete data from the analysis indicated that the pH equals 4.3. The condensate contains 2.6 ppm chloride and 7.3 ppm silica. No other species were reported.

4.5.2 Corrosion Tests

Limited corrosion tests have been done at Hatchobaru by Mitsubishi Heavy Industries (Mitsubishi 1979). Results of these tests in

FIGURE 4.5-1. LOCATION OF HATCHOBARU GEOTHERMAL RESOURCE

TABLE 4.5-1. CHEMISTRY OF SEPARATED FLUID FROM HATCHOBARU, JAPAN

COMPONENT	CONCENTRATION
<u>Key Species (ppm):</u>	
pH	3.4 - 8.4
Chloride ion (Cl^-)	1800 - 2450
Sulfate ion (SO_4^{2-})	70 - 241
Bicarbonate ion (HCO_3^-)	0 - 126
Carbonate ion (CO_3^{2-})	---
Hydrogen sulfide (H_2S)	---
Ammonium ion (NH_4^+)	---
<u>Other Species (ppm):</u>	
Total dissolved solids	4190 - 5590
Silica (SiO_2)	839 - 1340
Sodium (Na)	1100 - 1500
Potassium (K)	200 - 300

- : Data not available

Source: Yamasaki 1978

air-free steam and air-free condensate are summarized in Material Screening Tables 4.5-3 and 4.5-4.

4.5.2.1 Test Methods

Uniform corrosion rates and pitting were measured by exposing ASTM-type coupons to air-free geothermal steam and condensate for about one year; the actual test duration is not known. Uniform corrosion was measured by weight loss. Pitting was reported strictly as "occurred/did not occur" and was not quantified.

Susceptibility to stress corrosion cracking (SCC) or sulfide stress cracking (SSC) was measured by exposing three-point bend specimens stressed at 20, 40, 60, 80, and 100 percent of yield strength (0.02 percent offset yield strength) for periods up to one year. Specimens were examined

TABLE 4.5-2. COMPOSITION OF NONCONDENSABLE GAS IN STEAM FROM HATCHOBARU, JAPAN

Component	Percent Vol. in Steam	Percent Vol. in Gas Fraction
Total gas	0.071 - 0.288	
Carbon dioxide (CO ₂)	0.064 - 0.272	90.10 - 94.3
Hydrogen sulfide (H ₂ S)	0.0003 - 0.0002	0.4 - 0.1
Balance	0.007 - 0.016	9.6 - 5.6

Source: Yamasaki 1978

each week in the first two months and on alternate weeks in the following months. Results were reported as "failed/did not fail." The exact test conditions during these tests are not available. Table 4.5-2 reports the nominal chemistry of the steam during the tests. The temperature and pressure were not reported.

Tests were performed to determine if silver solder, which was used to attach Stellite erosion shields to last stage blading, loses strength when exposed to geothermal steam.

4.5.3 Results and Discussion

The available corrosion data for materials exposed to separated air-free steam and air-free condensate are presented in Table 4.5-5 and are discussed below. No crevice corrosion test data were reported.

Cast Iron

- ° The uniform corrosion rate of gray cast iron in air-free steam was 2.6 mpy. It was slightly higher (2.9 mpy) in air-free condensate. There is no information available on pitting, and no stress corrosion test was performed.

TABLE 4.5-3. MATERIAL SCREENING TABLE FOR GEOTHERMAL STEAM AT HATCHOBARU, JAPAN

MATERIAL TESTED	NON-AERATED STEAM				AERATED STEAM			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>								
Gray Cast Iron	B	--	--	--	--	--	--	--
<u>Low Alloy Steels</u>								
Carbon	B	--	--	--	--	--	--	--
Cr-Mo	B	--	--	--	--	--	--	--
2.5Ni-Cr-Mo-V	A	--	--	--	--	--	--	--
<u>Stainless Steels</u>								
12Cr-Mo	A	N	--	N	--	--	--	--
13Cr-3Mo	A	N	--	N	--	--	--	--
17-4 PH	A	--	--	N	--	--	--	--
T304	A	--	--	--	--	--	--	--
<u>Copper-Based Alloy</u>								
70-30 Brass	A	--	--	--	--	--	--	--
<u>Plating</u>								
Cr Plate	A	--	--	--	--	--	--	--
Al Galvanizing	A	--	--	--	--	--	--	--

KEY TO TABLE

- A - Uniform corrosion rate ≤ 1 mpy
 B - Uniform corrosion rate > 1 mpy but ≤ 10 mpy
 C - Uniform corrosion rate > 10 mpy but ≤ 50 mpy
 D - Uniform corrosion rate ≥ 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 -- No data available

Source: Mitsubishi 1979

TABLE 4.5-4. MATERIAL SCREENING TABLE FOR CONDENSATE AT HATCHOBARU, JAPAN

MATERIAL TESTED	NON-AERATED CONDENSATE				AERATED CONDENSATE			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>								
Gray Cast Iron	B	--	--	--	--	--	--	--
<u>Low Alloy Steels</u>								
Carbon	B	--	--	--	--	--	--	--
Cr-Mo	B	--	--	--	--	--	--	--
2.5Ni-Cr-Mo-V	B	--	--	--	--	--	--	--
<u>Stainless Steels</u>								
12Cr-Mo	A	N	--	X	--	--	--	--
13Cr-3Mo	A	N	--	N	--	--	--	--
17-4 PH	A	N	--	N	--	--	--	--
T304	A	--	--	--	--	--	--	--
<u>Copper-Based Alloy</u>								
70-30 Brass	B	--	--	--	--	--	--	--
<u>Plating</u>								
Cr Plate	A	--	--	--	--	--	--	--
Al Galvanizing	A	--	--	--	--	--	--	--

KEY TO TABLE

- A - Uniform corrosion rate < 1 mpy
 B - Uniform corrosion rate > 1 mpy but ≤ 10 mpy
 C - Uniform corrosion rate > 10 mpy but < 50 mpy
 D - Uniform corrosion rate ≥ 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 -- No data available

Source: Mitsubishi 1979

TABLE 4.5-5. CORROSION RESULTS AT THE HATCHOBARU, JAPAN GEOTHERMAL ELECTRIC POWER STATION

MATERIAL TESTED	NON-AERATED STEAM				NON-AERATED CONDENSATE			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Iron</u>								
Gray Cast Iron	2.6	--	--	--	2.9	--	--	--
<u>Low Alloy Steels</u>								
Carbon (wrought)	3.4	--	--	--	4.4	--	--	--
Carbon (cast)	2.0	--	--	--	3.1	--	--	--
Cr-Mo	1.8	--	--	--	3.2	--	--	--
2.5Ni-Cr-Mo-V	0.7	--	--	--	2.9	--	--	--
<u>Stainless Steels</u>								
12 Cr-Mo	0.02	N	--	N	0.3	N	--	X ^a
13 Cr-3Mo	--	N	--	N	--	N	--	N
17-4 pH	--	N	--	N	--	N	--	N
T304	<0.01	--	--	--	<0.01	--	--	--
<u>Copper Based Alloy</u>								
70-30 Brass	0.43	--	--	--	2.7	--	--	--
<u>Coatings</u>								
Cr Plate	.06	--	--	--	0.5	--	--	--
Al Galvanizing	0.02	--	--	--	N ^a	--	--	--
Phenol Paint	Base metal not corroded				Base metal not corroded			
Epoxy Paint	Base metal corroded ^b				Base metal corroded ^b			
Coal tar Epoxy Paint	Base metal not corroded				Base metal not corroded			

^aCracking occurs at stresses 40 percent of yield stress.^bSeverity of attack is not knownKEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

-- No data available

Source: Mitsubishi 1979

Carbon and Low Alloy Steels

- Wrought carbon steel corroded at 3.4 mpy in air-free steam and at 4.4 mpy in air-free condensate. Cast carbon steel performance was better: uniform corrosion rate was 2.0 mpy in steam and 3.1 mpy in condensate. No information about pitting or stress corrosion was available.
- Cr-Mo low alloy rotor steel corroded uniformly at 1.8 mpy in steam and at 3.2 mpy in condensate. No information about pitting or stress corrosion was available.
- 2.5 Ni-Cr-Mo-V rotor alloy corroded at 0.7 mpy in steam and at 2.9 mpy in condensate. No information about pitting and stress corrosion was available.

Stainless Steels

- 12Cr-Mo turbine blading alloy corroded at very low (0.02 mpy) rates in air-free geothermal steam. No pitting or stress corrosion cracking occurred. In condensate the uniform corrosion rate increased tenfold. No pitting occurred. Stress corrosion (probably sulfide stress cracking) occurred in specimens stressed at greater than 40 percent of the 0.02 percent yield strength. The hardness of this alloy was not given.
- No uniform corrosion data were reported for 13Cr-3 Mo turbine blading alloy or for 17-4 PH (precipitation hardening) stainless steel. No pitting of either alloy occurred. Both alloys resisted sulfide stress cracking. The hardness was not reported.
- AISI 304 corroded at less than 0.01 mpy in air-free steam and condensate. No data about pitting or stress corrosion were reported.

Copper-Based Alloy

- 70-30 Brass corroded at 0.43 mpy in air-free steam and at 2.7 mpy in air-free condensate. No information about pitting or stress corrosion was available.

Silver Solder

- ° The adhesive strength under shear stresses of silver solder (of undefined composition) exposed to air-free geothermal steam for 360 days decreased by four percent, compared to brazed joints which were not exposed to steam.

Protective Coatings

- ° Chromium plate on carbon steel corroded at 0.6 mpy in air-free steam and at 0.5 mpy in air-free condensate.
- ° Aluminum galvanizing corroded at 0.2 mpy in air-free steam. No detectable corrosion occurred in air-free condensate.
- ° Phenolic-based paint prevented the corrosion of carbon steel in both geothermal steam and condensate.
- ° Epoxy-based paint protected carbon steel in air-free steam. No corrosion of the base metal was observed. In air-free condensate, the base metal was corroded. The severity of attack was not reported.
- ° Epoxy-coal tar paint protected carbon steel in both air-free steam and air-free condensate. No corrosion of the base metal was observed.

4.5.4 Operating Experience

Operational performance reports of materials at the Hatchobaru Power Plant are proprietary.

REFERENCES

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4.6 MATSUKAWA, JAPAN

The Matsukawa geothermal plant is located on the north-eastern island of Honshu, as shown in Figure 4.6-1. When the site was being developed, the resource was liquid-dominated and produced acidic water and steam. The resource has since stopped producing liquid and is now steam-dominated. A 20MW generating plant went into operation in September 1966.

4.6.1 Fluid Chemistry

The fluid chemistry at Matsukawa is unique among the sites discussed in this volume. At the time of the materials tests, the fluid from this site was an acid sulfate water with little chloride. The resource has since become steam-dominated. Tables 4.6-1, 4.6-2, and 4.6-3 present the range of fluid, steam, and steam condensate chemistries reported during the liquid-dominated phase when materials tests were performed. No information is available about the composition of the steam produced in the resource's vapor-dominated phase.

4.6.2 Corrosion Tests

Corrosion tests in separated steam were conducted by Tokyo Shibaura Electric Company (Toshiba) to provide a basis for materials selection for the turbines (Yoshida, Hoashi and Miyazaki 1968). Results are summarized in Materials Screening Table 4.6-4.

4.6.2.1 Method

Three-point bending stress corrosion specimens stressed at yield strength and ASTM-type coupons were exposed to the low velocity steam for 127 days. All specimens were evaluated by ASTM methods. The actual chemistry of the steam is not known. The low velocity steam had the following characteristics: $T = 282^{\circ}\text{F}$, velocity = 33 ft/sec, pressure = 56.9 psia, and carry-over moisture = 3.2 percent. Oxygen concentration is presumed to be zero.

In the erosion-corrosion tests, specimens were exposed to steam from nozzles. The velocity was 656 ft/sec. One set of specimens was exposed to steam with 3.2 percent moisture (carryover), while another set was exposed to steam with 30 percent carryover. The maximum penetration was measured after 127 days exposure.

4.6.2.2 Results and Discussion

Detailed results of the test are presented in Table 4.6-5. The method of presentation in the source document (a dot diagram) does not allow precise quantification of many of the results.

FIGURE 4.6-1. LOCATION OF MATSUKAWA GEOTHERMAL RESOURCE

TABLE 4.6-1. COMPOSITION OF SEPARATED WATER AT MATSUKAWA, JAPAN^a

COMPONENT	CONCENTRATION (ppm)
Chloride ion (Cl ⁻)	9.2 ^d - 12.4 ^c
Sulfate ion (SO ₄ ²⁻)	1708 ^d - 1780 ^c
Total carbon dioxide (CO ₂) ^b	26 ^c
Hydrogen sulfide (H ₂ S)	10 ^d - 52 ^d
Ammonia (NH ₃)	---
Silica (SiO ₂)	612 ^d - 635 ^c

^a pH = 4.9^b Total carbon dioxide includes carbon dioxide, carbonate ion, and bicarbonate ion.^c Source: Ellis and Mahon 1977^d Source: Yoshida, Hoashi, and Miyazaki 1968

---: Data not available

TABLE 4.6-2. COMPOSITION OF GEOTHERMAL STEAM AT MATSUKAWA, JAPAN

COMPONENT	PERCENT (VOL) IN STEAM	
Carbon dioxide (CO ₂)	0.18 ^a	0.15-0.50 ^b
Hydrogen sulfide (H ₂ S)	0.03 ^a	0.03-0.11 ^b
Balance	<.01 ^a	- - -

--- Data not available

^a Source: Ellis and Mahon 1977^b Source: Yoshida, Hoashi, and Miyazaki 1968

TABLE 4.6-3. COMPOSITION OF CONDENSATE OF GEOTHERMAL STEAM FROM MATSUKAWA^a

COMPONENT	CONCENTRATION (ppm)
pH	4.0 - 5.9
Chloride ion (Cl^-)	0.5 - 3.9
Sulfate ion (SO_4^{2-})	2.1 - 72.0
Bicarbonate ion (HCO_3^-)	0.0 - 9.1
Carbon dioxide (CO_2)	15.4 - 83.0
Hydrogen sulfide (H_2S)	11.9 - 102
Silica (SiO_2)	1.3 - 26.7
Total dissolved solids (TDS)	15 - 173

Source: Nakamura et al. 1970

Cast Iron and Low Alloy Steels

The uniform corrosion rate of these materials was from 20 to 25 mpy in low velocity steam containing 3.2 percent droplet carryover. All three alloys (cast iron, 1Cr-1.5Mo-0.25V, and carbon steel) were susceptible to crevice corrosion, though the severity of the attack was not reported. No stress corrosion cracking (SCC) or sulfide stress cracking (SSC) occurred.

Stainless Steels

The uniform corrosion rates of AISI 304 and AISI 316 were less than 1 mpy, and no localized corrosion or SCC occurred. AISI 410 (turbine blading) also showed a corrosion rate of less than 1 mpy, but pits 4.3 mils deep were observed after 127 days. The corrosion rate of AISI 405 was 2 mpy with pits approximately 2 mils deep after the same exposure. AISI 420 showed similar pitting but more rapid uniform corrosion. None of these alloys was susceptible to SCC or SSC. All showed crevice corrosion.

TABLE 4.6-4. CORROSION SCREENING RESULTS FROM MATSUKAWA, JAPAN: SEPARATED STEAM

MATERIALS TESTED	NON-AERATED STEAM				AERATED STEAM			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Cast Iron	C	N	X	N	-	-	-	-
Carbon Steel	C	N	X	N	-	-	-	-
1Cr-1.5Mo-0.25V	C	N	X	N	-	-	-	-
AISI 304	A-B	N	N	N	-	-	-	-
AISI 316	A	N	N	N	-	-	-	-
AISI 405	B	X	X	N	-	-	-	-
AISI 410	B	X	X	N	-	-	-	-
AISI 420	B	X	X	N	-	-	-	-
<u>Copper Base</u>								
Copper	C	N	X	N	-	-	-	-
P-Bronze	B-C	X	X	N	-	-	-	-
Naval Brass	B-C	N	N	N	-	-	-	-
<u>Other Bases</u>								
Aluminum	A-B	X	N	N	-	-	-	-
Aluminum 5052	A-B	X	N	N	-	-	-	-
Aluminum 6063	A-B	X	N	N	-	-	-	-
Monel 400	B	N	X	N	-	-	-	-
Titanium	A	N	N	N	-	-	-	-

KEY TO TABLE

A - general corrosion rate < 1 mpy
 B - general corrosion rate > 1 mpy but < 10 mpy
 C - general corrosion rate > 10 mpy but < 50 mpy
 D - general corrosion rate > 50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 - - No data available

Source: Yoshida, Hoashi, and Miyazaki 1968.

TABLE 4.6-5. CORROSION TEST RESULTS AT MATSUKAWA, JAPAN: SEPARATED STEAM

MATERIALS TESTED	LOW VELOCITY STEAM (33fps)				HIGH VELOCITY STEAM (656fps)	
	Uniform Corrosion (mpy)	Pitting (mpy)	Crevice Corrosion	SCC	3% Moisture Erosion (mpy)	30% Moisture Erosion (mpy)
<u>Iron Base</u>						
Cast Iron	19.7	N	X	N	--	--
Carbon Steel	25.0	N	X	N	--	--
1Cr-1.5Mo-0.25V	24.5	N	X	N	--	--
AISI T304	1-10	N	N	N	19	205
AISI T316	<1	N	N	N	--	--
AISI T405	2.0	5.6	X	N	--	--
AISI T410	<1	12.4	X	N	37	190
AISI T420	1-5	5.5	X	N	--	--
<u>Copper Base</u>						
Copper	10-50	N	X	N	--	--
P-Bronze	<10	X	X	N	75	310
Naval Brass	10-50	N	N	N	--	--
<u>Other Bases</u>						
Aluminum	1-10	4.5	N	N	--	--
Aluminum 5052	1-10	12.4	N	N	--	--
Aluminum 6063	1-10	18.1	N	N	--	--
Monel 400	1-10	N	X	N	49	310
Titanium	<1	N	N	N	--	--
Stellite	--	--	--	--	<1	4

KEY TO TABLE

N - indicated form of corrosion not detected
 X - indicated form of corrosion detected but not quantified
 -- - no data available

Source: Yoshida, Hoashi, and Miyazaki 1968.

Copper Alloys and Monel 400

All of these alloys except copper had uniform corrosion rates of 1 to 10 mpy, and all except copper and phosphor bronze showed slight (unquantified) pitting. The corrosion rate of copper was greater than 30 mpy. All the alloys except Naval Brass were susceptible to crevice corrosion, while none failed by SCC or SSC.

Aluminum Alloys

The uniform corrosion rate of the aluminum alloys (1100, 5052, and 6063) was 5 mpy or less. After 127 days, all the alloys were pitted. Depth varied from 4 to 16 mils. No crevice corrosion or SCC was observed.

Titanium

Commercial titanium was not corroded at all. No localized attack or SCC occurred.

Erosion-Corrosion Results

Only Phosphor Bronze, Monel 400, AISI 410, AISI 304, and Stellite (unknown grade) were tested for resistance to erosion-corrosion. Stellite was very resistant to 3.2 percent droplet carryover at 656 ft/sec with a maximum penetration rate of less than 1 mpy. The erosion-corrosion rates of other alloys varied from 19 to 75 mpy. In the 30 percent droplet-656 ft/sec steam, the erosion rate of all alloys except Stellite was extremely severe (200 to 300 mpy), while Stellite eroded at 4 mpy.

4.6.3 Operating Experience

Little operating experience was available from the Matsukawa geothermal-electric plant.

4.6.3.1 Bore Casing and Wellhead Equipment

A problem with scale deposition in the bore of one well has been reported (Sato 1970).

4.6.3.2 Steam Transmission Lines

The lines are carbon steel and are satisfactory if oxygen is excluded. Problems with valve sticking have occurred. Gate and butterfly-type valves are used. Operating practice calls for periodic cycling of valves to prevent sticking. Safety valves are the spring-type and stick very readily. They are also cycled regularly (Sato 1970).

4.6.3.3 Turbine

The turbine has four single-row impulse stages. Blades are 12Cr, and the casing is carbon steel. After about two years of operation, blade failure occurred in the second stage. It was concluded that failure was due to corrosion-fatigue, and blade thickness was increased to compensate for reduced fatigue endurance limit (Sato 1970).

4.6.3.4 Gas Ejectors

Noncondensable gases (approximately 4900 lb/hr) are removed from the barometric condenser by two-stage steam gas ejectors. The tail pipes of the ejectors were originally carbon steel. After two years the tail pipes were corroded to the extent that the ejectors did not work properly. The tail pipes were replaced with stainless steel (unspecified grade) (Sato 1970).

REFERENCES

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- Nakamura, H., Sumi, K., Katagiri, K., and Iwata, T., 1970. The geological environment of Matsukawa Geothermal Area, Japan. Geothermics 2(pt.1):221.
- Sato, H., 1970. On Matsukawa Geothermal Power Plant. Geothermics 2(pt.2):1546.
- Yoshida, H., Hoaski, J., and Miyazaki, M., 1968. Corrosion control in geothermal steam turbines. Proc. Amer. Power Conference. 30:965-73.

4.7 OTAKE, JAPAN

The single flash (bore flashing) geothermal power plant at Otake taps a liquid-dominated reservoir at a depth of 985 to 1640 feet. The location is shown in Figure 4.7-1. The reservoir temperature is estimated to be 487°F (Ellis and Mahon 1977). The MW plant utilizes separated steam at 20.6 psig and 260°F (turbine inlet conditions). Steam is condensed in a barometric (direct contact) condenser. Noncondensable gases are extracted with mechanical pumps rather than by steam ejectors. The plant has been in operation since 1967 (Usui and Aikawa 1970).

4.7.1 Fluid Chemistry

The resource at Otake is a neutral chloride water in equilibrium with quartz. Chloride concentration of water separated at atmospheric pressure is 1010 to 1760 ppm, depending on the well sampled. The pH varies from 6.7 to 8.4. The nominal composition of the separated fluid is given in Table 4-7.1.

The separated steam at Otake contains from 0.05 to 0.51 weight percent noncondensable gases (approximately 0.02 to 0.2 volume percent). The gas is about 94 percent carbon dioxide and 0.5 to 2 percent hydrogen sulfide. The noncondensable gas analysis is given in Table 4-7.2. The available data on the composition of steam condensate is given in Table 4-7.3.

4.7.2 Corrosion Tests

Corrosion tests were performed at Otake in separated air-free geothermal steam and condensate (Mitsubishi 1979). Results are summarized in Materials Screening Tables 4-7.4 and 4-7.5.

Test Methods

The test methods used for Otake materials are the same as those used for Hatchobaru (Section 4.5.2). Tables 4.7-2 and 4.7-3 report the nominal environment during the tests.

Fatigue-corrosion tests were performed on smooth and notched test specimens of 13Cr-Mo and 17-4PH blading alloys and 2.5Ni-Cr-Mo-V rotor alloy using a cantilever rotating bending fatigue tester. The test chamber was designed so that steam at a known velocity impinged directly against the test pieces. The velocity of the steam was not reported. Care was taken to prevent aeration of the steam. Fatigue tests were also performed in air and boiler-quality steam to establish the comparative effect of geothermal and pure steam on reduction in fatigue endurance limit.

FIGURE 4.7-1. LOCATION OF OTAKE GEOTHERMAL RESOURCE

TABLE 4.7-1. RANGE OF COMPOSITION OF SEPARATED FLUID FROM THE OTAKE
GEOTHERMAL ELECTRIC PLANT^a

COMPONENT	CONCENTRATION (ppm)
Chloride ion (Cl^-)	1010 - 1760
Sulfate ion (SO_4^{2-})	96 - 200
Bicarbonate ion (HCO_3^-)	46 ^b
Carbonate ion (CO_3^{2-})	-
Hydrogen sulfide (H_2S)	-
Ammonium ion (NH_4^+)	0.06 ^c
Silica (SiO_2)	414 - 668

^a pH = 6.7 - 8.4

^b Source: Ellis and Mahon 1977

^c Source: Mitsubishi 1979

-: No data available

Source: Hayashida and Ezima 1970 (except as noted)

Tests were performed to determine if silver solder, used to attach Stellite erosion shields to last stage blading, loses strength when exposed to hydrogen sulfide-laden steam. Tensile specimens were prepared by brazing two pieces of 12Cr with silver solder to form tensile specimens with the brazed joint parallel to the direction of applied stress. The stress required to cause failure of the brazed joint was measured prior to exposure, after three months exposure, and after six months exposure. Five measurements were made (Mitsubishi 1979).

Results and Discussion

The results of the uniform, pitting, and stress corrosion tests are presented in Table 4.7-6 and are discussed below. There are no data available concerning crevice corrosion of materials at the Otake plant.

TABLE 4.7-2. COMPOSITION OF STEAM FROM SEPARATORS - OTAKE, JAPAN

COMPONENT	RANGE OF CONCENTRATIONS ^a	CONCENTRATION IN CORROSION TEST ^b
Total Non-condensable gas (wt %)	.05 - 0.510	0.510
Carbon dioxide (CO ₂) (Vol %)	93.0 - 95.03	95.57
Hydrogen sulfide (H ₂ S) (Vol %)	0.57 - 2.02	1.27
Balance (Vol %)	2.60 - 6.00	3.16

^aSource: Hayashida and Ezima 1970

^bSource: Mitsubishi 1979

Gray Cast Iron

Gray cast iron corroded at 0.7 mpy in both nonaerated steam and in the resulting nonaerated condensate. Pitting results were not reported, and no stress corrosion cracking test was performed.

Carbon and Low Alloy Steels

Wrought carbon steel corroded uniformly at 1.6 mpy in steam. It did not pit and was resistant to stress corrosion cracking. The corrosion rate in air-free condensate was less than 0.05 mpy; no pitting or stress corrosion cracking occurred.

The corrosion of cast carbon steel was 2.1 mpy in the steam, slightly higher than the wrought carbon steel. Pitting and stress corrosion cracking did not occur. The corrosion rate was 0.03 mpy in condensate, with similar pitting and stress corrosion cracking results.

TABLE 4.7-3. COMPOSITION OF STEAM CONDENSATE AT OTAKE, JAPAN

COMPONENT	RANGE OF CONCENTRATION ^a	CONCENTRATION IN CORROSION TEST ^b
pH	5.0-5.7	5.2
	<u>ppm</u>	<u>ppm</u>
Chloride ion (Cl^-)	1.0-9.0	2.6
Sulfate ion (SO_4^{-2})	-	-
Bicarbonate ion (HCO_3^-)	-	-
Carbonate ion (CO_3^{-2})	-	-
Hydrogen sulfide (H_2S)	-	-
Ammonia (NH_3)	-	-
Silica (SiO_2)	0.0-0.7	1.5

^aSource: Hayashida and Ezima 1970.

^bSource: Mitsubishi 1979.

- No Data Available

Cr-Mo low alloy steel (undefined composition) corroded uniformly at 1.7 mpy in steam and at 0.1 mpy in condensate. No pitting or stress corrosion cracking occurred in either environment.

Ni-Cr low alloy steel (of undefined composition) showed corrosion behavior equivalent to the Cr-Mo steel. No pitting or stress corrosion cracking was reported.

The uniform corrosion rate of 2.5Ni-Cr-Mo-V rotor steel was 1.8 mpy in air-free steam and 0.1 mpy in air-free condensate. No pitting or stress corrosion cracking was reported. Results of the fatigue tests indicate that this alloy was susceptible to corrosion fatigue in both clean steam and geothermal steam. The reduction in Fatigue Endurance Limit (FEL) at 10^7 cycles (compared to fatigue in air) was 16.1 percent in clean steam

FIGURE 4.7-4. MATERIAL SCREENING TABLE FOR STEAM AT THE OTAKE POWER PLANT

MATERIAL TESTED	NONAERATED STEAM				AERATED STEAM			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>								
Gray Cast Iron	A	-	-	-	-	-	-	-
<u>Low Alloy Steels</u>								
Carbon	B	N	-	N	-	-	-	-
Cr-Mo	B	N	-	N	-	-	-	-
Ni-Cr	B	N	-	N	-	-	-	-
2.5Ni-Cr-Mo-V	B	N	-	N	-	-	-	-
<u>Stainless Steels</u>								
12Cr maraging	A	N	-	X	-	-	-	-
13Cr	A	X	-	N	-	-	-	-
13Cr-3Mo	A	X	-	X	-	-	-	-
T304	A	N	-	N	-	-	-	-
T316	A	N	-	N	-	-	-	-
<u>Aluminum Based Alloys</u>								
Aluminum	A	-	-	-	-	-	-	-
Silumin	A	-	-	-	-	-	-	-
Duralumin	A	-	-	-	-	-	-	-
Cast Aluminum	A	-	-	-	-	-	-	-
<u>Other Bases</u>								
Hastelloy	A	-	-	-	-	-	-	-
Copper	A	-	-	-	-	-	-	-
70-30 Brass	A	N	-	N	-	-	-	-
Lead	A	-	-	-	-	-	-	-

Key to Table

A - uniform corrosion rate ≤ 1 mpy
 B - uniform corrosion rate > 1 mpy but ≤ 10 mpy
 C - uniform corrosion rate > 10 mpy but ≤ 50 mpy
 D - uniform corrosion rate > 50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 - No data available

See Table 4.7-6 for more detailed results.

TABLE 4.7-5. MATERIAL SCREENING TABLE FOR CONDENSATE AT THE OTAKE POWER PLANT

MATERIAL TESTED	NONAERATED STEAM				AERATED STEAM			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Iron</u>								
Gray Cast Iron	A	-	-	-	-	-	-	-
<u>Low Alloy Steels</u>								
Carbon	A	N	-	N	-	-	-	-
Cr-Mo	A	N	-	N	-	-	-	-
Ni-Cr	A	N	-	N	-	-	-	-
2.5Ni-Cr-Mo-V	A	N	-	N	-	-	-	-
<u>Stainless Steels</u>								
12Cr maraging	A	N	-	X	-	-	-	-
13Cr	A	X	-	N	-	-	-	-
13Cr-3Mo	-	X	-	N	-	-	-	-
T304	A	N	-	N	-	-	-	-
T316	A	N	-	N	-	-	-	-
<u>Aluminum-Based Alloys</u>								
Aluminum	A	-	-	-	-	-	-	-
Silumin	A	-	-	-	-	-	-	-
Duralumin	A	-	-	-	-	-	-	-
Cast Aluminum	A	-	-	-	-	-	-	-
<u>Other Bases</u>								
Hastelloy ^a								
Copper	B	-	-	-	-	-	-	-
70-30 Brass	A	N	-	N	-	-	-	-
Lead	B	-	-	-	-	-	-	-

^aunspecified grade

KEY TO TABLE

- A - uniform corrosion rate ≤ 1 mpy
- B - uniform corrosion rate > 1 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but ≤ 50 mpy
- D - uniform corrosion rate > 50 mpy
- N - Indicated form of corrosion not detected
- X - indicated form of corrosion detected
- No data available

See Table 4.7-6 for more detailed results.

TABLE 4.7-6. CORROSION TEST RESULTS AT THE OTAKE POWER PLANT

MATERIAL TESTED	NON-AERATED STEAM 212-248°F				NON-AERATED CONDENSATE 104°F			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>								
Gray Cast Iron	0.7	-	-	-	0.7	-	-	-
<u>Low Alloy Steels</u>								
Carbon (wrought)	1.6	N	-	N	< 0.05	N	-	N
Carbon (cast)	2.1	N	-	N	0.03	N	-	N
Cr-Mo	1.7	N	-	N	0.1	N	-	N
Ni-Cr	1.8	N	-	N	0.1	N	-	N
2.5 Ni-Cr-Mo-C	1.8	N	-	N	0.1	N	-	N
<u>Stainless Steels</u>								
12 Cr Maraging	0.1	N	-	X ^a	< 0.05	N	-	X ^a
13 Cr	< 0.05	X ^a	-	N	< 0.05	X ^a	-	N
13 Cr-Mo	-	X ^a	-	N	-	X	-	N
AISI T304	0.05	N	-	X ^a	< 0.05	N	-	N
AISI T316	0.05	N	-	N	< 0.05	N	-	N
<u>Aluminum Base</u>								
Aluminum	< 0.05	-	-	-	< 0.05	-	-	-
Silumin ^b	< 0.05	-	-	-	< 0.05	-	-	-
Duralumin ^c	< 0.05	-	-	-	< 0.05	-	-	-
Al (cast)	< 0.05	-	-	-	< 0.05	-	-	-
<u>Other Bases</u>								
Hastelloy ^d	0.1	-	-	-	< 0.03	-	-	-
Copper	0.6	-	-	-	1.0	-	-	-
70-30 Brass	< 0.05	N	-	N	< 0.05	N	-	N
Lead	0.3	-	-	-	1.5	-	-	-
<u>Coatings</u>								
Cr Plate	0.2	-	-	-	< 0.05	-	-	-
Al Galvanizing	< 0.05	-	-	-	1.2	-	-	-
Phenol Paint	No damage of base metal				No damage of base metal			
Epoxy Paint	Base metal slightly corroded				No damage of base metal			
Tar Epoxy	Base metal corroded				No damage of base metal			

^a not quantified.^b 11-14Si - Al(bal).^c 3.5-4.5Cu, .3-.6Mg, .5-1Fe, Al.^d Grade not specified.Key to Table

N - indicated form of corrosion not detected.

X - indicated form of corrosion detected.

- - No data available.

Source: Mitsubishi 1979

and 41.4 percent in geothermal steam. The same comparisons at 10^8 cycles of stress were 17.2 percent reduction in clean steam and 49.4 percent reduction in geothermal steam.

Stainless Steel

12Cr maraging steel corroded at 0.1 mpy in air-free steam and at less than 0.05 mpy in air-free condensate. No pitting occurred in either environment. Stress corrosion cracking or sulfide stress cracking occurred in both environments.

13Cr turbine blading alloy resisted stress corrosion cracking and sulfide stress cracking. The hardness of this alloy is not known. Sulfide stress cracking may occur at high (Rc greater than 25) levels. Pitting of unquantified depth occurred in both air-free steam and air-free condensate.

13Cr-3Mo showed pitting of unquantified depth in both air-free geothermal steam and in air-free condensate. No information about the uniform corrosion rate is given, but it is probably comparable to 13Cr. This alloy resisted stress corrosion cracking or sulfide stress cracking at the hardness (unknown) tested. This alloy is clearly susceptible to corrosion fatigue. The reduction in FEL (compared to fatigue in dry air) at 10^7 cycles of stress is 13.4 percent in clean steam and 26.2 percent in geothermal steam. At 10^8 cycle of stress, the reductions in FEL are 13.6 percent in clean steam and 38.5 percent in geothermal steam.

17-4PH precipitation hardening stainless steel was tested for corrosion fatigue only. At 10^7 cycles of stress, the reduction of FEL was 15.7 percent in clean steam and 24.7 percent in geothermal steam, while at 10^8 cycles of stress, the reductions were 19.3 percent (clean steam) and 44.6 percent (geothermal steam). No uniform corrosion, pitting, or stress corrosion cracking results were reported.

AISI 304 resisted pitting in both air-free condensate and air-free steam. Uniform corrosion rates were less than 0.05 mpy. Stress corrosion cracking occurred in the geothermal steam but not in condensate.

AISI 316 did not pit in either geothermal steam or geothermal condensate. Uniform corrosion was less than 0.05 mpy, and no stress corrosion cracking occurred in either environment.

Aluminum Alloys

Four aluminum alloys were tested in both steam and condensate: aluminum, Silumin (11-14 Si), Duralumin (4Cu, 0.3-0.6 Mg, 0.5-1 Fe), and cast aluminum. All showed uniform corrosion rates of less than 0.05 mpy. No information about the pitting or stress corrosion was available.

Other Alloys

Copper corroded at less than 1 mpy in both steam and condensate. No information about pitting and stress corrosion was available.

70-30 Brass showed a uniform corrosion rate of less than 0.05 mpy in both steam and condensate. No pitting or stress corrosion was reported.

Lead corroded at 0.3 mpy in steam and 1.5 mpy in condensate. No data about pitting or stress corrosion were reported.

Hastelloy (unspecified grade) corroded at less than 0.05 mpy in steam and condensate. Pitting or stress corrosion results were not reported.

The adhesive strength of silver solder joints exposed to geothermal steam for 286 days was reduced 21 percent, compared to similar joints not exposed to steam.

Coating and Plating

Chrome plating on carbon steel resulted in low corrosion rates (0.2 mpy in steam and less than 0.05 mpy in condensate).

Aluminum galvanizing was better in steam (corrosion rate less than 0.05 mpy) but worse in condensate corrosion (rate equals 1.2 mpy).

Three coatings (phenol paint, epoxy paint, and coaltar epoxy paint) were tested on carbon steel. They were evaluated on the basis of damage to underlying metal. In steam there was no damage to steel coated with phenol paint, slight corrosion of metal covered with epoxy paint, and the metal covered with coal-tar epoxy paint was corroded. All of these coatings prevented corrosion of steel in air-free condensate.

Relative Effect of Clean and Geothermal Steams on Corrosion-Fatigue

Comparison of S-N curves (fatigue curves) for three alloys (13Cr-3Mo blading alloy, 17-4PH blading alloy, and 2.5Ni-Cr-Mo-V rotor alloy), fatigued in air and corrosion-fatigued in clean (boiler) steam and geothermal steam, show that at any given number of cycles of stress, the reduction in FEL is greater in geothermal steam than for clean steam. Also, the deterioration of FEL with time is more rapid in geothermal steam than in clean steam. This is illustrated in Figure 4.7-2.

FIGURE 4.7-2. COMPARISON OF REDUCTION IN FATIGUE ENDURANCE LIMIT FOR GEOTHERMAL AND BOILER QUALITY STEAM AT 212°F

Source: Mitsubishi 1979

4.7.3 Operating Experience

The power plant at Otake logged 89,345 hours of operation out of a possible 92,968 hours from 1967 through 1977. This results in an availability factor of 0.961. The plant operated at its full MW capacity only during the first year. In 1977, the mean output was only 6.4MW. The decline is due to decreases in the steam supply. Several wells have failed, and no new ones have been successfully completed.

Currently only two wells are supplying steam for plant operation, while several others serve as reinjection wells. Loss of reinjectivity is severe. Reinjection flow rates have decreased at 7 percent per month (DiPippo 1979). Details about materials performance at the Otake plant are proprietary.

REFERENCES

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4.8 CERRO PRIETO, MEXICO

The Cerro Prieto geothermal resource is located in northwestern Mexico as shown in Figure 4.8-1. The liquid-dominated resource utilization mode is a single-flash (bore flashing). In 1976, 53 deep wells, with depths of 2300 to 6550 feet, had been drilled in the Cerro Prieto area. The bottom 500 to 1000 feet penetrate the geothermal fluid production zone.

The wells are cemented to the top of the production zone. Fluid is produced through either gun-perforated casing or preslotted casing extending to the bottom of the hole. High enthalpy water at 530° to 610°F is conducted to the surface through the 7-5/8 inch production casing. As the water ascends in the production casing, the hydrostatic pressure drops, and the water partially flashes to steam. Flow through the well tree is a two-phase fluid containing 20 to 40 weight percent steam. At the wellhead, the fluid passes through a Webre-type centrifugal separator and is sent to a secondary separator at the power plant. Separated water is sent to an evaporating pond.

Each well yields 20 to 80 tons of steam per hour at 100 psig. In 1976, 13 wells provided steam to two units of 37.5 MW each (at full load) at a steam rate of 20.7 lbm/kWh (EIC 1976).

4.8.1 Fluid Chemistry

Isotopic analyses indicate that the Cerro Prieto geothermal fluid is meteoric and derived mainly from the Colorado River (EIC 1976). The production strata is sandstone with a lava overlay. The geothermal fluid is saturated with silica (from quartz) at the temperatures and pressure present in the production strata (EIC 1976). Analyses of geothermal fluid from three production wells are given in Table 4.8-1, and well data from the three wells is given in Table 4.8-2. The three analyses (from 115 analyses presented in Cosner and Apps 1978) show the range of fluid compositions at Cerro Prieto.

4.8.2 Corrosion Tests

From 1969 to 1970, a corrosion test program was performed jointly by the Comision Federal de Electricidad de Mexico and Tokyo Shibaura Company (Toshiba) of Japan. Results are summarized in Materials Screening Tables 4.8-3 and 4.8-4. The purpose of the test program was to confirm the corrosion resistance of previously-selected materials to be used for construction of the Cerro Prieto power plant (Mercado, A. 1976).

4.8.2.1 Methods

Uniform and pitting corrosion rates were measured using coupons. Stress corrosion specimens were U-bends stressed beyond the yield point and

FIGURE 4.8-1. LOCATION OF CERRO PRIETO GEOTHERMAL RESOURCE

TABLE 4.8-1. COMPARISON OF FLUIDS FROM PRODUCTION WELLS AT CERRO PRIETO

COMPONENT	CONCENTRATION					
	Low TDS ^a (Well M-8)		Medium TDS ^a (Well M-31)		High TDS ^a (Well M-11)	
	Pre-Flash Fluid ^b	After-Flash Fluid ^c	Pre-Flash Fluid ^b	After-Flash Fluid ^c	Pre-Flash Fluid ^b	After-Flash Fluid ^c
<u>Key Species</u>						
pH	5.43 ^d	8.21 ^e	5.35 ^d	8.05 ^e	5.34 ^d	7.90 ^e
	ppm	ppm	ppm	ppm	ppm	ppm
Chloride (Cl ⁻)	9,040	10,128	8,820	13,205	11,400	16,129
Sulfate (SO ₄ ²⁻)	9	10	3	18	27	12
Bicarbonate (HCO ₃ ⁻)	38	32.5	28	57.8	27	59.1
Carbonate (CO ₃ ²⁻)	-	11.4	-	6.3	-	0
Carbon Dioxide (CO ₂)	2,580	-	2,210	-	1,250	-
Hydrogen Sulfide (H ₂ S)	624	-	593	-	310	-
<u>OTHER SPECIES</u>						
TDS ^a	-	17,068	-	22,284	-	27,123
Sodium (Na)	4,730	5,257	4,410	6,913	5,600	8,229
Potassium (K)	1,180	1,310	1,110	1,540	1,230	2,032
Calcium (Ca)	272	258	287	463	369	550
Magnesium (Mg)	0.2	0.04	0.1	0.16	0.8	0.34
Silica (SiO ₂)	590	974	490	833	610	1,345
Boron (B)	12	15.5	11	18	13	-
Iron (Fe)	-	-	-	0.26	-	-
Lithium (Li)	10.9	14.5	11.1	18.4	13.7	25.2

^aTotal Dissolved Solids^bCalculated fluid composition corrected for steam loss^cSeparator discharge fluid at 1 atm and 212°F after steam flash^dCalculated pH^epH at 77°F

-: Data not available

SOURCE: Cosner and Apps 1978

retained under stress with a bolt. The erosion-corrosion specimens were rods 2.4 inches long and 0.39 inch in diameter. Erosion was evaluated by weight loss. The specimens for mechanical properties tests were the flat tensile and the flat fatigue type.

Specimens were exposed to nonaerated steam at 61 psig and 297°F. The steam contained 19,500 ppm (wt) carbon dioxide, 2,000 ppm (wt) hydrogen sulfide, and 13.3 ppm chloride. Moisture content was less than 1 percent. Velocity was not reported.

TABLE 4.8-2. WELL CHARACTERISTICS OF THREE WELLS AT CERRO PRIETO

WELL CHARACTERISTICS	WELL M-8	WELL M-31	WELL M-11
Temperature (bottom of hole)	581°F	595°F	502°F
Production depth	4000 ft	3800 ft	3775 ft
Production flow	112.8 ton/hr	173.8 ton/hr	59.3 ton/hr
Steam fraction	37%	34%	27%
Wellhead pressure	98 psig	109 psig	98 psig
Separator pressure	92 psig	102 psig	92 psig
Enthalpy	590.0 Btu/lb	608.0 Btu/lb	489.4 Btu/lb

NOTE: These three wells were selected to present the range of geothermal fluid compositions at Cerro Prieto. At least 53 wells have been drilled at Cerro Prieto, and analysis under production conditions is available for 21 wells.

SOURCE: Cosner and Apps 1978

TABLE 4.8-3. CERRO PRIETO CORROSION SCREENING TABLE: SEPARATED STEAM

MATERIAL TESTED	NON-AERATED STEAM					AERATED STEAM				
	Uniform Corrosion	Pitting	General Corrosion	SCC	Erosion	Uniform Corrosion	Pitting	Service Corrosion	SCC	Erosion
Low Alloy Steels										
Low Carbon	-	-	-	-	B	-	-	-	-	-
1Cr-1Mo-0.25V	B	-	-	X	B	B	-	-	X	-
1.5Cr-1Al-0.25Mo	-	X	-	-	*	-	B	-	-	-
3.5Ni-1.75Cr-Mo-V	A	X	-	-	B	C	X	-	N	-
ASTM A285	B	-	-	-	B	B	-	-	-	-
Stainless Steels										
AISI T304	-	-	-	-	A	-	-	-	-	-
AISI T410	-	-	-	-	-	-	-	-	-	-
12Cr	A	X	-	N	B	B	X	-	X	-
12Cr-Mo-W	A	X	-	N	A	B	X	-	X	-
12Cr-0.2Al	A	-	-	N	A	B	-	-	N	-
15Cr-1.7Mo	A	X	-	N	A	A	X	-	N	-
Non-ferrous Alloys										
Stellite #6	-	-	-	-	-	B	X	-	-	-
Deoxidized Copper	-	-	-	N	-	C	-	-	X	-
Naval Brass	-	-	-	-	-	-	-	-	-	-
Aluminum	-	-	-	-	-	B	X	-	-	-

Key To Table

- A - uniform corrosion rate <1 mpy
- B - uniform corrosion rate >1 mpy but <10 mpy
- C - uniform corrosion rate >10 mpy but <50 mpy
- D - uniform corrosion rate >50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- * - weight gain
- - no data available

See Table 4-8.6 for more detailed information.

TABLE 4.8-4. CERRO PRIETO CORROSION SCREENING TABLE: CONDENSATE

MATERIAL TESTED	NON-AERATED CONDENSATE				AERATED CONDENSATE			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Steels</u>								
Low Carbon	-	-	-	-	B-C	N	-	N
1Cr-Mo-0.25V	-	-	-	-	-	-	-	-
1.5Cr-1Al-0.25Mo	-	-	-	-	-	-	-	-
3.5Ni-1.75Cr-Mo-V	-	-	-	-	-	-	-	-
ASTM A285	-	-	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI T304	-	-	-	-	A	X*	-	N
AISI T410	-	-	-	-	A-E	X	-	-
12Cr	-	-	-	-	-	-	-	-
12Cr-Mo-W	-	-	-	-	-	-	-	-
12Cr-0.2Al	-	-	-	-	-	-	-	-
15Cr-1.7Mo	-	-	-	-	-	-	-	-
<u>Non-ferrous Alloys</u>								
Stellite #6	-	-	-	-	-	-	-	-
Deoxidized Copper	-	-	-	-	B	N	-	-
Naval Brass	-	-	-	-	B	N	-	-
Aluminum	-	-	-	-	A-B	X*	-	-

Key To Table

- A - uniform corrosion rate <1 mpy
 B - uniform corrosion rate >1 mpy but <10 mpy
 C - uniform corrosion rate >10 mpy but <50 mpy
 D - uniform corrosion rate >50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 * - pitted badly in service
 - - no data available

Refer to Table 4.8-7 for more detailed information.

The aerated steam was at 14.7 psia and 158°F. It contained 16,000 ppm (wt) carbon dioxide, 1,600 ppm (wt) hydrogen sulfide, 7 ppm chloride, and less than 1 percent moisture. The velocity and the amount of oxygen were not reported.

The high velocity steam was not aerated. The pressure was 56.8 psig at 284°F. The composition was the same as that of nonaerated steam. The velocity was 426 feet per second.

The condensate was aerated at atmospheric pressure. Temperature was 104° to 113°F. The chloride concentration was 50 to 60 ppm, and pH varied from 6.4 to 7.3. Coupons were exposed to condensate at 0.002 feet per second and 1.6 feet per second.

After exposure, the uniform corrosion rate and the erosion rate were measured by weight loss. Maximum pit depth was determined by an unspecified method. No measurements of crevice corrosion were performed. The various mechanical properties, yield strength, tensile strength, elongation, etc., were measured and compared with specimens not exposed to geothermal environments. A similar procedure was used for the fatigue specimens. Reduction in the fatigue endurance limit (FEL) which is measured in this way is not as severe as if the specimens were cyclically loaded during the exposure (Mercado, A. 1976).

The U-bends were examined for macroscopic cracking as well as microscopic fractures. No distinction was made between chloride stress corrosion cracking and sulfide stress cracking (Mercado, A. 1976).

4.8.2.2 Results and Discussion

The results of the tests and details of test conditions are presented in Tables 4.8-5 through 4.8-10. No distinction was made between chloride stress corrosion cracking and sulfide stress cracking.

Corrosion Results in Steam

Low Alloy Steels

The corrosion rate of carbon steel (ASTM A285) in nonaerated steam was satisfactory (1.6 mpy) for turbine casing and piping. Aeration of the steam almost doubled the corrosion rate. No pitting was reported.

The corrosion rate of 1Cr-Mo-0.25V steel was similar to the corrosion of carbon steel in nonaerated steam. No pitting was reported. Microscopic cracks were observed in the stress corrosion specimen. Aeration increased uniform corrosion rates by a factor of five. One of two stress corrosion specimens failed.

TABLE 4.8-5. COMPOSITION OF TEST MEDIA USED FOR CORROSION STUDY AT CERRO PRIETO

FLUID CHARACTERISTICS	TEST MEDIA				
	Non-Aerated Steam	High Velocity Steam	Aerated Steam	High Velocity Condensate	Low Velocity Condensate
Pressure	61 psig	56.8 psig	14.7 psig	14.7 psig	14.7 psig
Temperature	297°F	285°F	158°F	113°F	104°F
Carbon dioxide (CO ₂)	19500 ppm	19500 ppm	16000 ppm	-	-
Hydrogen sulfide (H ₂ S)	2000 ppm	2000 ppm	1600 ppm	-	-
Chloride (Cl ⁻)	13.3 ppm	13.3 ppm	7.0 ppm	60 ppm	50 ppm
pH	a	a	a	6.4-7.3	6.8-7.0
Velocity	-	426 fps	-	1.6 fps	0.002 fps
Moisture	0.7%	0.6%	0.7%	a	a

^a Does not apply to this phase

-: No data available

SOURCE: Mercado A. 1976

TABLE 4.8-6. CORROSION AND EROSION RESULTS USING STEAM AT CERRO PRIETO

MATERIAL TESTED	CORROSION ^a								EROSION ^{a,b} High Velocity Steam (mpy)
	NON-AERATED STEAM				AERATED STEAM				
	Uniform Corrosion (mpy)	Pitting (mpy)	Crevice Corrosion	SCC ^c	Uniform Corrosion (mpy)	Pitting (mpy)	Crevice Corrosion	SCC ^c	
LOW ALLOY STEELS									
Low Carbon	-	-	-	-	-	-	-	-	1.43
1Cr-Mo-0.25V	1.57	-	-	2/2 ^d	8.27	-	-	1/2	3.28
1.5 Cr-1Al-0.25Mo	-	38.18	-	-	-	33.46	-	-	+ ^g
3.5 Ni-1.75 Cr-Mo-V	0.63	4.72	-	-	13.40	27.56	-	0/3 ^e	1.59
ASTM A285	1.57	-	-	-	2.56	-	-	-	2.70
STAINLESS STEELS									
AISI 304	-	-	-	-	-	-	-	-	0.12
AISI 410	-	-	-	-	-	-	-	-	-
12 Cr	0.39	0.94	-	0/3	3.94	66.93	-	0/3 ^d	1.09
12 Cr-Mo-W	0.16	0.94	-	0/3	2.72	62.99	-	2/2	0.44
12 Cr-0.2 Al	0.75	-	-	0/3	4.33	-	-	0/3 ^e	0.72 ^h
15 Cr-1.7 Mo	0.18	5.90	-	0/3	0.55	47.27	-	0/3	0.46
NON-FERROUS MATERIALS									
Stellite #6	-	-	-	-	2.24	106.30	-	-	0.46
Deoxidized Copper	-	-	-	0/3	20.07	-	-	2/2 ^f	-
Naval Brass	-	-	-	-	-	-	-	-	2.6 ^g
Aluminum	-	-	-	-	3.27	114.10	-	-	-

^aDuration of exposure = 150 days^bErosion rate was calculated from weight loss data, assuming uniform attack.^cStress corrosion cracking (not differentiated as to mechanism). Reported as no. samples failed/no. samples tested^dMicroscopic cracks observed.^eIntergranular corrosion^fFailure due to uniform corrosion^gWeight gain^hDuration of exposure = 90 days

-: Data not available

SOURCE Mercado, A. 1976

TABLE 4.8-7. CORROSION RESULTS USING CONDENSATE AT CERRO PRIETO

MATERIAL TESTED	LOW-VELOCITY CONDENSATE ^a				HIGH VELOCITY CONDENSATE ^a			
	Uniform Corrosion (mpy)	Pitting (mpy)	Crevice Corrosion (mpy)	SCC ^b	Uniform Corrosion (mpy)	Pitting (mpy)	Crevice Corrosion	SCC ^b
<u>LOW ALLOY STEELS</u>								
Low Carbon	12.20	N	-	0/3	27.56	-	-	-
1Cr-Mo-0.25V	-	-	-	-	-	-	-	-
1.5Cr-1Al-0.25Mo	-	-	-	-	-	-	-	-
3.5Ni-1.75Cr-Mo-V	-	-	-	-	-	-	-	-
ASTM A285	-	-	-	-	-	-	-	-
<u>STAINLESS STEELS</u>								
AISI 304	0.03	N	-	0/3	0.01	N	-	-
AISI 410	0.59	38.19	-	-	3.15	33.46	-	-
12 Cr	-	-	-	-	-	-	-	-
12 Cr-Mo-W	-	-	-	-	-	-	-	-
12 Cr-0.2Al	-	-	-	-	-	-	-	-
15 Cr-1.7Mo	-	-	-	-	-	-	-	-
<u>NON-FERROUS MATERIALS</u>								
Stellite #6	-	-	-	-	-	-	-	-
Deoxidized copper	9.45	N	-	0/4	2.52	-	-	-
Naval brass	2.83	N	-	0/3	8.66	-	-	-
Aluminum	0.16	N	-	0/2	14.57	-	-	-

^a Duration of exposure = 150 days^b Stress corrosion cracking (not differentiated as to mechanism). Reported as no. samples failed/no. samples tested.KEY TO TABLE

N: Indicated form of corrosion not detected

-: Data not available

SOURCE: Mercado, A. 1976

TABLE 4.8-8. EFFECT OF NON-AERATED STEAM ON MATERIAL PROPERTIES AT CERRO PRIETO

MATERIAL TESTED	BEFORE EXPOSURE				EXPOSED TO NON-AERATED STEAM				
	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)	% Decrease ^a
<u>LOW ALLOY STEELS</u>									
Low Carbon	-	-	-	-	-	-	-	-	-
1Cr-Mo-0.25V	54.4	44.1	17.3	23.5	53.9	43.5	16.3	17.1	27.4
1.5Cr-1Al-0.25Mo	-	-	-	-	-	-	-	-	-
3.5Ni-1.75Cr-Mo-V	57.7	49.6	17.3	28.4	57.3	50.7	16.3	17.4	38.6
ASTM A285	-	-	-	-	-	-	-	-	-
<u>STAINLESS STEELS</u>									
AISI 304	-	-	-	-	-	-	-	-	-
AISI 410	-	-	-	-	-	-	-	-	-
12 Cr	48.0	39.9	19.6	26.1	47.3	38.8	20.1	21.3	18.5
12 Cr-Mo-W	65.2	54.5	15.6	31.0	65.3	51.3	16.3	26.5	14.6
12 Cr-0.2Al	39.5	24.3	25.1	17.1	39.0	24.8	27.6	13.9	18.8
15 Cr-1.7Mo	31.7	20.1	31.1	16.5	30.8	18.8	32.1	14.5	11.7
<u>NON-FERROUS MATERIALS</u>									
Stellite #6	-	-	-	-	-	-	-	-	-
Deoxidized copper	11.5	15.8	23.1	-	15.4	14.1	8.5	-	-
Naval brass	-	-	-	-	-	-	-	-	-
Aluminum	-	-	-	-	19.9	-	10.8	-	-

^a percent decrease in endurance limit

-: Data not available

SOURCE: Mercado, A. 1976

TABLE 4.8-9. EFFECT OF AERATED STEAM ON MATERIAL PROPERTIES AT CERRO PRIETO

MATERIAL TESTED	BEFORE EXPOSURE				EXPOSED TO AERATED STEAM			
	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)
<u>LOW ALLOY STEELS</u>								
Low Carbon	-	-	-	-	-	-	-	-
1Cr-Mo-0.25V	54.4	44.1	17.3	23.5	53.0	41.1	13.2	-
1.5Cr-1Al-0.25Mo	-	-	-	-	-	-	-	-
3.5Ni-1.75Cr-Mo-V	57.7	49.6	17.3	28.4	53.6	45.0	10.9	-
ASTM A285	-	-	-	-	-	-	-	-
<u>STAINLESS STEELS</u>								
AISI 304	-	-	-	-	-	-	-	-
AISI 410	-	-	-	-	-	-	-	-
12 Cr	48.0	39.9	19.6	26.1	48.1	37.2	12.8	-
12 Cr-Mo-W	65.2	54.5	15.6	31.0	60.5	44.5	4.8	-
12 Cr-0.2Al	39.5	24.3	25.1	17.1	36.6	24.6	20.2	-
15 Cr-1.7Mo	31.7	20.1	31.1	16.5	30.8	18.5	25.4	-
<u>NON-FERROUS MATERIALS</u>								
Stellite #6	-	-	-	-	-	-	-	-
Deoxidized copper	11.5	15.8	23.1	-	-	-	-	-
Naval brass	-	-	-	-	-	-	-	-
Aluminum	-	-	-	-	-	-	-	-

-: Data not available

SOURCE: Mercado, A. 1976

TABLE 4.8-10. EFFECT OF LOW VELOCITY CONDENSATE ON MATERIAL PROPERTIES AT CERRO PRIETO

MATERIAL TESTED	BEFORE EXPOSURE				EXPOSED TO LOW VELOCITY CONDENSATE			
	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)	Tensile Strength (ksi)	Yield Strength (ksi)	2" % Elongation	Endurance Limit (ksi)
LOW ALLOY STEELS								
Low Carbon	-	-	-	-	24.0	11.9	37.7	-
1Cr-Mo-0.25V	54.4	44.1	17.3	23.5	-	-	-	-
1.5Cr-1Al-0.25Mo	-	-	-	-	-	-	-	-
3.5Ni-1.75Cr-Mo-V	57.7	49.6	17.3	28.4	-	-	-	-
ASTM A285	-	-	-	-	-	-	-	-
STAINLESS STEELS								
AISI 304	-	-	-	-	42.3	21.9	70.5	-
AISI 410	-	-	-	-	37.4	23.0	27.3	-
12 Cr	48.0	39.9	19.6	26.1	-	-	-	-
12Cr-Mo-W	65.2	54.5	15.6	31.0	-	-	-	-
12Cr-0.2Al	39.5	24.3	25.1	17.1	-	-	-	-
15Cr-1.5Mo	31.7	20.1	31.1	16.5	-	-	-	-
NON-FERROUS MATERIALS								
Stellite #6	-	-	-	-	-	-	-	-
Deoxidized copper	11.5	15.8	23.1	-	15.4	15.2	21.0	-
Naval brass	-	-	-	-	28.0	21.4	24.8	-
Aluminum	-	-	-	-	20.5	-	7.3	-

-: Data not available

SOURCE: Mercado, A. 1976

In nonaerated steam, the general corrosion rate of 3.5Ni-Cr-Mo-V alloy was less than 1Cr-Mo-0.25V alloy. It corroded at 0.6 mpy. It was not stress corrosion tested in nonaerated steam. The fatigue endurance limit (FEL) decrease was 39 percent. Aeration increased uniform corrosion by 20-fold. Stress corrosion specimens showed intergranular attack.

In aerated steam, 1.5Cr-1Al-0.25Mo alloy (nitrided steel) showed a partial spalling (exfoliation) but had good uniform corrosion resistance. Pitting was 30 to 40 mpy in both aerated and nonaerated steam.

Stainless Steels

In nonaerated steam, 12Cr alloy (used for turbine buckets) had a very low (less than 0.5 mpy) uniform corrosion rate. There was slight pitting. It was not susceptible to stress corrosion cracking. Resistance to erosion-corrosion was acceptable. There was no change in tensile strength, but there was a decrease in fatigue endurance limit (15 to 19 percent). Aeration increased uniform corrosion ten times and pitting 70 times. Microscopic cracks were observed on the stress corrosion specimen.

In nonaerated steam, 12Cr-Mo-W steel was comparable to 12Cr in terms of uniform corrosion, pitting, and stress corrosion cracking. Erosion-corrosion was half as severe as the erosion of 12Cr steel. Changes in mechanical properties were similar to 12Cr steel. Aeration caused intergranular corrosion of the stress corrosion specimen, a tenfold increase in uniform corrosion, and a 70-fold increase in pitting.

In nonaerated steam, 12Cr-0.2Al alloy (used for nozzle partitions) had a low (less than 1 mpy) uniform corrosion rate. No pitting was reported. The alloy was resistant to stress corrosion, and erosion-corrosion resistance was similar to 12Cr steel. Aeration increased uniform corrosion six-fold, and no pitting was reported. 15Cr-1.7Mo steel was not susceptible to stress corrosion in aerated steam. Erosion-corrosion resistance was quite good. Changes in tensile and yield strength were not as severe as for 12Cr-Mo-W.

Corrosion Results in Condensate

The corrosion rate in high velocity (1.5 feet per second) condensate was excessive for materials commonly used in heat exchangers (deoxidized copper, naval brass, and carbon steel). The pitting rate of aluminum was greater than 100 mpy. AISI 410 steel pitted at a rate of more than 30 mpy. Uniform corrosion was ten times that of AISI 304. AISI 304 steel showed the best corrosion resistance of the stainless steels tested in condensate. Uniform corrosion was very low. Pitting and stress corrosion were not detected.

Plant experience indicated that AISI 304 heat exchanger tubing would not serve in aerated condensate. Titanium tubes have given good service.

Epoxy coatings cured at high temperature showed no deterioration in low velocity condensate after 150 days of exposure.

The condensate used in the tests was aerated, and the hydrogen sulfide concentration was not given. The pH was about 7.

4.8.3 Operating Experience

The successful operation of the Cerro Prieto geothermal power plant has provided valuable materials experience that may be used in the design of U.S. plants. The similarity of geothermal fluids in southern California makes the Cerro Prieto data particularly useful.

Carbon and low alloy steels have served satisfactorily in non-aerated liquid or steam. When oxygen was introduced into the geothermal media, carbon steel was severely corroded. Stainless steels, titanium, or nonmetallic materials are required in aerated steams.

Materials experience in the various parts of the power plant is discussed below.

4.8.3.1 Bore Casings and Surface Equipment

Several problems and two blowouts, due to the rupture or collapse of bore casings, have occurred at Cerro Prieto. It is not known when and to what extent stress corrosion, sulfide stress cracking, galvanic corrosion, joint or casing erosion, or excess stress have been involved because the broken casings could not be recovered (Mercado, A. 1976).

After geothermal wells have been completed, they remain out of production until their temperature, which decreased during drilling, increases again and facilitates activation. During this time, internal pipe walls of some of the wells have been attacked by elevated concentrations of hydrogen sulfide. Reservoir gases such as carbon dioxide and hydrogen sulfide flow into a well out of production and cause the water level to oscillate significantly. Hydrogen sulfide becomes concentrated in the coldest area near the surface and attacks the pipe. The extent of damage has not been measured, but when a well is activated, the initial discharge of water has a higher iron sulfide content (Mercado S. 1978). Sulfide stress cracking is also a hazard under these conditions. To minimize these problems, wells are activated as soon as possible after completion.

Sulfide stress cracking appears to have occurred once under conditions similar to those described above. Well M-5, cased with API grade H-40 steel, failed when cold water was injected during repair operations (Mercado, A. 1976). This behavior corresponds to that at Wairakei (Section 4.10) where casing steels H-40 and K-55 have failed in cold, hydrogen sulfide-bearing condensate (Fooks 1964; Foster, Marshall, and Tombs 1964; Marshall and Tombs 1969; Smith 1964).

Casing collapse has been mainly attributed to poor cementation procedures (Mercado, A. 1978). After the cement was mixed, some water remained trapped in the annular spaces between the surface casing and the production casing. When the cement hardened and the well production began, the trapped water expanded due to the increased temperature. The resulting high pressure caused the collapse. This problem was solved by using higher resistance surface casing (N 80) and by altering the cement/water proportions during mixing.

Fluid leakage between well casings, or between casings and the walls of the well, lead to cement degradation and to expansion and contraction of the well casing. Small fractures allow the passage of geothermal fluids from the production strata at the bottom of the well to the surface. The result is bubbling and escape of gases and steam, which promote corrosion on the outside of the well casing. Intensive maintenance using temperature resistant paints or by adding high temperature lubricants prevents corrosion of the well casing (Mercado, S. 1978).

Galvanic coupling of production pipe with packing flanges has promoted crevice corrosion of the casing at the wellhead. This has been corrected by preventing metal-to-metal contact of the pipes at the surface and by eliminating the packing flanges. The space is filled with cement or high temperature lubricating greases (Mercado, A. 1976, Mercado, S. 1978).

Two techniques are used to detect failures and corrosion in production casing at Cerro Prieto. Lead seals are used to determine whether casing problems are due to collapse, joint breakage, or casing failure. In the second method, depth caliper electric logs are used to detect thinning due to corrosion of the production casing. The results of the log method are confirmed by comparing them with data obtained from casing samples recovered during well reworking operations.

Pitting and general corrosion of the interiors of mild steel surface pipes carrying nonaerated geothermal media have been insignificant. Erosion-corrosion has been frequently observed at surface installations where there is sand-water-steam flow at high velocity (Mercado, A. 1976).

Purge leaks and atmospheric discharges occasionally form salt deposits on valves, Christmas trees, and pipes. The surface corrosion that results is controlled by constant scraping and the application of protective paints.

The Cerro Prieto discharge was initially passed through steel vertical silencers. The combination of geothermal fluids and atmospheric oxygen caused severe corrosion of the steel. This problem was eliminated by constructing special silencers with concrete bases and towers of wood or fiberglass (Mercado S. 1978).

4.8.3.2 Steam Conduction System

Table 4.8-11 gives the typical composition of steam as it enters the steam conduction lines. Nominal steam temperature is 320°F.

TABLE 4.8-11. TYPICAL COMPOSITION OF SEPARATED STEAM AT PRIMARY SEPARATOR OUTLET AT CERRO PRIETO

COMPONENT	CONCENTRATION ppm (wt)
Chloride ion (Cl^-)	16.0
Sulfate ion (SO_4^{-2})	---
Silica (SiO_2)	1.1
Ammonia (NH_3)	120
Hydrogen Sulfide (H_2S)	1300
Carbon dioxide (CO_2)	13000
Sodium (Na)	8.4
Potassium (K)	2.4
Magnesium (Mg)	0.1
Boron (B)	0.2
Calculated droplet carryover ^a	0.1 percent

^aBased on comparison with separated water

---: No data available

Source: Mercado, S. 1979

Carbon steel steam conduction lines are susceptible to slight internal attack and may become coated with an iron sulfide film. If this occurs, the film may become dislodged and block steam traps or enter the turbine. Extensive maintenance of steam traps has been employed to decrease the buildup of iron sulfide flakes. In some conduction lines, the problem has been solved by implementing a continuous condensate purge and removing the steam traps (Mercado, S. 1978).

Erosion was a common material problem during the early stages of well production. The erosion was attributed to high fluid velocities and small quantities of sand in the fluid (Mercado, S. 1978). It occurred in the pipe elbows between the well and the water/steam separator. Substitution with blind flanged Tee fittings, which produce a hydraulic cushion for the solid particles, minimized erosion. A new well is also allowed to flow freely for five to ten days before it is connected to the water/steam separator. This reduces the amount of sand in the fluid.

Safety valves were used to protect the water/steam separator from overpressure. However, the valves in the protective AISI 316 elbow were ruined by corrosion caused by vapor leakage in the seats. In place of safety valves, rupture disks which are protected from the saline environment are now used with good results (Mercado, A. 1978).

4.8.3.3 Turbines

During the first two years of operation, the turbines were inspected twice. There was no observed corrosion or cracking of the turbine buckets (12Cr steel). At the sixth stage of blades, the Stellite No. 6 facings were in very good condition and had only slight erosion of the silver used to solder the facings to the 12Cr steel blades (Mercado, A. 1976). The major problem was the scaling of silica in the first stage nozzles and buckets (Mercado, A. 1976; EIC 1976). This problem was due to the poor separation of water and steam in the wellhead and secondary separators. The poor separation allowed carryover of droplets supersaturated with silica and calcium carbonate (EIC 1976).

After two years of operation, improved steam separators were installed to give 99.99 percent pure quality steam. Table 4.8-12 presents typical chemistry of the steam at the turbine inlet. The service cycle has been extended to 18 months, and a two-year cycle is possible (Mercado S., 1978).

The rotor and 12Cr turbine buckets have shown only slight attack after five years of operation. Their highest attrition rate is due to erosion from water droplets, carryover of iron sulfide particles in the steam, or sandblasting. Sandblasting is carried out during preventive maintenance to eliminate the scale which is regularly deposited during operation. No cracking of 12Cr blades has occurred. Corrosion is slightly

TABLE 4.8-12. COMPOSITION OF STEAM AT TURBINE INLET AT CERRO PRIETO

COMPONENT	CONCENTRATION ppm (wt)
Ammonium ion (NH_4^+)	110
Hydrogen sulfide (H_2S)	1500
Carbon dioxide (CO_2)	141000
Sodium ion (Na^+)	0.4
Silica (SiO_2)	0.2
Chloride ion (Cl^-)	0.8
Quality = 99.99 percent	

Source: Mercado, S. 1979

more accentuated in seals where steam is mixed with geothermal gases and atmospheric oxygen (Mercado, S. 1978; 1979).

4.8.3.4 Cooling Water System

The major corrosion problems at Cerro Prieto have been in the cooling water system. The cooling water is aerated steam condensate containing hydrogen sulfide, carbon dioxide, ammonia, chlorides, other impurities, and sulfide-oxidizing bacteria.

Extensive corrosion occurred originally on the water side of the aluminum tubes in the heat exchanger of the oil cooling system. A large percentage of the tubes were perforated in 15 days of operation, and all showed signs of pitting. The aluminum tubes were replaced by Type 304 stainless steel tubes, and some of these were also perforated after several months. The problem is now controlled by draining and drying the tubes when the equipment is out of operation. This helps because bacterial growth, which promotes the pitting, accelerates when the water is not flowing. Titanium tubing is planned for use in the next unit (Mercado, S. 1978).

Originally, the tubes in the heat exchanger of the hydrogen cooling system of the generator were aluminum. These tubes were severely pitted, but were not perforated because the walls were thicker. They were replaced with titanium tubes, and there has been no detectable corrosion in four years (Mercado, S. 1978).

In barometric (direct-contact) condenser, cooled condensate containing oxygen is sprayed into the steam. The condenser is carbon steel covered with an epoxy-coating on the upper part and clad with AISI 304 stainless steel on the bottom. Water removes the protective coating in some areas, and the carbon steel walls are attacked. There has been no corrosion through the stainless steel layer. Condensers for future units will be clad with AISI 316L stainless steel. The gas ejector contains some carbon steel tubes which corrode due to the steam, gases, and oxygen. The chimneys used for high altitude gas discharge are fiberglass and have performed very well (Mercado, S. 1978). The barometric legs of the secondary condenser were originally carbon steel. They suffered severe corrosive attack and were destroyed in two years. The problem was solved when they were replaced with fiberglass tubing. Fiberglass or AISI 316 stainless steel is planned for use in future units (Mercado, S. 1978).

The carbon steel valves which handle the cooling water have suffered severe attack. They are now protected with a layer of AISI 316 stainless steel and an epoxy coating.

Closed concrete channels are used for conducting cooling water between the condenser and the cooling tower. These channels were originally protected with coal tar epoxy. After two years of operation, loosening of the epoxy coating and attack of the concrete in the upper part of the channel were noted. The attack had become so extensive after four years that the cement was degraded, and sand and gravel were dislodged. Repairs were made, and the concrete was protected by polyvinyl chloride (PVC) covers.

The combination of hydrogen sulfide, steam, and anaerobic bacteria caused degradation in a zone of the concrete channel ceilings containing almost no air. Concrete below the water line was not attacked because the water is treated with biocides to control bacteria. Some of the bacteria found in the system oxidize hydrogen sulfide to sulfuric acid, resulting in low pH values that lead to degradation. Future installations at Cerro Prieto will prevent degradation of the concrete on channel ceilings by flooding or installing PVC plate coverings.

During four years of operation, wood in the cooling tower has degraded slightly in the upper part of the spray zone and in the region of the water level. Parts of the transmission supports and ventilation motors are carbon steel that is protected with coal-tar epoxy. Slight corrosion has resulted where the paint has worn off. Most of the screws and metal

fittings are AISI 304 stainless steel and have shown slight pitting. During preventive maintenance shutdowns, the wood is treated with bactericides and algicides in the attacked areas. The carbon steel parts are cleaned and coated with epoxy paint (Mercardo, S. 1978).

4.8.3.5 Separated (Waste) Geothermal Fluid System

Silica deposition is prevented by transmitting the waste fluid at high temperature (320°-356°F) from the separators to the holding pond. Precipitation occurs in the pond (Ellis and Mahon 1977).

There have been few corrosion problems in the carbon steel pipes which transport the waste fluid. Table 4.8-13 gives the typical composition of the waste stream.

TABLE 4.8-13. COMPOSITION OF SEPARATED GEOTHERMAL WATER
AT CERRO PRIETO^a

COMPONENT	CONCENTRATION (ppm)
Chloride (Cl^-)	16045
Sulfate (SO_4^{-2})	6
Bicarbonate (HCO_3^-)	74
Carbonate (CO_3^{-2})	2
Fluoride (F^-)	2
Ammonium ion (NH_4^+)	---
Hydrogen sulfide (H_2S)	---
Silica (SiO_2)	1250
Bromide (Br^-)	31

^a_{pH} = 7.7

--- No data available

Source: Mercado, S. 1979

There has been a case in which severe scaling and corrosion occurred. Interruptions in the flow exposed the internal walls of the pipe to combined attack by salts and atmospheric oxygen. If the lines are kept hot, there is almost no internal corrosion. Lines are not presently insulated, and some external attack by the salt spray and oxygen results (Mercado, S. 1978).

4.8.3.6 Electrical System

The electrical system is generally protected by using clean rooms with filtered air conditioning systems. In unprotected areas, copper wire plated with tin or cadmium has been problem-free. Some of the silver and copper parts have been attacked by hydrogen sulfide and have required maintenance. Exterior high voltage contacts in the substation are copper that was covered with gold before being placed in operation. These contacts have given no problems (Mercado, S. 1978).

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4.9 BROADLANDS, NEW ZEALAND

The broadlands geothermal field is located about 12.5 miles north of Wairakei on the North Island of New Zealand (see Figure 4.9-1). This reservoir has been described as vapor-dominated (Ellis and Mahon 1977; Grant 1977). By 1977, a total of 31 wells had been drilled at Broadlands. Wells are cased to depths of 1360 to 5100 feet. Total well depth varies from 2500 to 7900 feet. The wells tap two-phase carbon dioxide/steam/liquid water fluid at 500° to 520°F (Ellis and Mahon 1977).

Materials tests are being performed at Broadlands. The resource will be developed as a geothermal-electric resource.

4.9.1 Fluid Chemistry

The fluid chemistry and physical properties of the resource are dominated by the noncondensable gases; in this case, carbon dioxide. The carbon dioxide increases the vapor pressure of the fluid to values much higher than the saturated water vapor pressure. It has been estimated that a liquid reservoir exists at some depth below 6600 feet. This reservoir may contain water at 570° to 590°F. The water contains approximately 1100 ppm chloride and as much as 6 weight percent dissolved carbon dioxide at partial pressures of 1500 to 2700 psi (Ellis and Mahon 1977; Grant 1977). At the depths (1400 to 5100 feet) tapped by the existing wells, the geothermal fluid is a liquid-vapor, two-phase substance containing about 0.6 weight percent carbon dioxide at partial pressures of about 120 to 210 psi. The tapped fluid contains 0.02 weight percent hydrogen sulfide at partial pressures of about 1.5 psia and 5 to 20 ppm by weight ammonia.

Table 4.9-1 shows the mean and range of carbon dioxide and hydrogen sulfide concentrations in the total discharge from 16 wells at Broadlands. The values in this table represent the total carbon dioxide and hydrogen sulfide in the two-phase fluid. Separated steam contains around 2.5 weight percent noncondensable gas (Braithwaite and Kichti 1979).

The separated water is a neutral chloride solution containing around 1600 ppm chloride. After separation, the average pH equals 8.2. The mean and range of composition of water separated at one atmosphere from 18 wells are given in Table 4.9-2.

4.9.2 Material Tests

An extensive program of materials tests is being performed at Broadlands (Conover 1979). These tests will measure susceptibility of 36 alloys to uniform and localized corrosion, sulfide stress cracking (SSC), chloride stress corrosion cracking (SCC), erosion, and fatigue.

FIGURE 4.9-1. LOCATION OF BROADLANDS GEOTHERMAL RESOURCE

TABLE 4.9-1. NONCONDENSABLE GAS IN TOTAL DISCHARGE FROM
16 WELLS AT BROADLANDS

		Carbon Dioxide (CO ₂)	Hydrogen Sulfide (H ₂ S)	Carbon dioxide/ Hydrogen sulfide (CO ₂ /H ₂ S)
Moles/100 moles	mean	971	10.0	-
	range	108-2770	2.8-19.3	-
Weight percent	mean	2.55	0.0193	-
	range	0.26-6.7	0.005-0.036	-
Mole ratio	mean	-	-	97.3
	range	-	-	36-395

—: Data not available

Source: Ellis and Mahon 1977

At this time, only preliminary uniform corrosion, pitting and crevice corrosion results are available (Braithwaite and Kichti 1979). These results are summarized in Materials Screening Table 4.9-3.

4.9.2.1 Methods and Conditions

Uniform and localized corrosion investigations were conducted on site in seven geothermal process streams originally drawn from Well BR 22. These seven fluids are described in Table 4.9-4.

Test coupons were obtained and prepared according to ASTM Recommended Practices for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (Gilbert 1956) and Conducting Plant Corrosion Tests (Grant 1977). Prepared coupons were mounted onto racks which were inserted and removed with the test vessels at operating temperature. Diffuser plates prevented direct impingement of incoming fluids on the coupons.

Before testing, the coupons were weighed to 0.01 mg accuracy. They were cleaned after testing to remove adherent corrosion products.

TABLE 4.9-2. COMPOSITION OF SEPARATED FLUID^a AT BROADLANDS

COMPONENT	CONCENTRATION (ppm)		
	mean (18 wells)	range (18 wells)	
<u>Key species:</u>			
Chloride ion	(Cl ⁻)	1618	528-1985
Sulfate ion	(SO ₄ ⁻²)	14.2	3.4-45
Bicarbonate ion	(HCO ₃ ⁻)	526	78-1820
Carbonate ion	(CO ₃ ⁻²)	--	--
Hydrogen sulfide	(H ₂ S)	--	<1-2
Ammonium ion	(NH ₄ ⁺)	3.08	1.2-12.0
<u>Other Species:</u>			
Silica	(SiO ₂)	--	265-1126
Sodium	(Na)	--	570-1510
Potassium	(K)	--	85-237
Calcium	(Ca)	--	1.1-8.55
Boron	(B)	--	23.4-56.5
Arsenic	(As)	--	1.0-5.7 ^b

^a separated at atmospheric pressure; pH = 7.4-9.1 (mean 8.21)

^b range of 10 wells

-- : no data available

Source: Ellis and Mahon 1977

TABLE 4.9-3. MATERIALS SELECTION TABLE FOR BROADLANDS, NEW ZEALAND

MATERIAL TESTED	NONAERATED					AERATED	
	Bore Fluid	Separated Water	Separated Steam	Wet Steam	Condensate	Wet Steam	Condensate
Cast Irons							
Gray	ANX-	AXX-	AXX-	AXX-	BNX-	CXX-	D---
Ni-Resist Type 1	ANX-	AXX-	ANX-	AXX-	AXX-	CXX-	C---
Steels							
Carbon (1018)	AXX-	AXX-	AXX-	AXX-	BNX-	CXX-	DXN-
Cr-Mo (4140)	AXX-	AXX-	BXX-	AXX-	BX--	CXX-	CXX-
Stainless Steels							
AISI 410	----	----	----	AXX-	----	----	----
AISI 304	----	----	----	AXX-	----	----	----
AISI 316	----	----	----	AXX-	----	----	----
AISI 321	----	----	----	AXX-	----	----	----
AISI 347	----	----	----	AXX-	----	----	----
Sandvik 2RK65	----	----	----	AXX-	----	----	----
Sandvik 3RE60	----	----	----	AXX-	----	----	----
E-Brite 26-1	----	----	----	AXX-	----	----	----
Carpenter 20Cb3	----	----	----	AXX-	----	----	----
FV 520 (B)	----	----	----	AXX-	----	----	----
Incoloy 825	----	----	----	AXX-	----	----	----
Copper Alloys							
Deoxidized Copper	----	----	----	ANN-	----	----	BNN-
2Al-brass	----	----	----	ANN-	----	----	BNN-
Titanium Alloys							
Titanium	----	----	----	ANN-	----	----	ANN-
Ti-6Al-4V (IMI 318)	----	----	----	ANN-	----	----	ANN-
Ti-4Al-4Mo (IMI 558)	----	----	----	ANN-	----	----	ANN-

KEY TO TABLE

- A - uniform corrosion rate $\leq$ 1.0 mpy
 B - uniform corrosion rate $>$ 1.0 mpy but $\leq$ 10 mpy
 C - uniform corrosion rate $>$ 10 mpy but $<$ 50 mpy
 D - uniform corrosion rate $\geq$ 50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 - - no data available

Source: Braithwaite and Kichti 1979

TABLE 4.9-4. MATERIALS TEST ENVIRONMENTS AT BROADLANDS, NEW ZEALAND

FLUID CHARACTERISTICS		TEST STREAM						
		Bore Fluid	Separated Water	Dry Steam (HP)	Wet Steam (LP)	Wet Aerated Steam (LP)	Nonaerated Condensate	Aerated Condensate
Physical Conditions	Temperature	320°F	313°F	320°F	221°F	223°F	Ambient	Ambient
	Pressure (psig)	79	79	79	3	5	28	5
	Phase	2-phase	liquid	vapor	vapor	vapor	liquid	liquid
	Liquid Fraction (wt)	-	100%	-	10%	10%	100%	100%
	Velocity ft/min	4.76	0.066	3.81	70.7	42.6	0.0039	0.0033
Chemistry	pH	-	7.5	5.7	-	-	0.15	6.0
	PPM							
Chloride	(Cl ⁻)	-	-	-	-	-	-	-
Sulfate	(SO ₄)	-	9.6	none	-	-	0.4	13.4
Hydrogen Sulfide	(H ₂ S)	-	10.9	323.8 ^a	327.2 ^a	388.5 ^a	81.8	8.9
Ammonia	(NH ₃)	-	4.8	40.0	-	-	40.02	38.1
Carbon Dioxide	(CO ₂)	-	-	20900	-	-	2120 ^b	356 ^b
Iron	(Fe)	-	-	-	-	-	12.6	11.4
Oxygen	(O ₂)	-	none	none	none	3% air	none	3% air

^a - value high due to collection method

^b - calculated

- - no data available

Source: Braithwaite and Kitchi 1975

Cleaned coupons were washed in cold and hot distilled water, dried in warm air, and then vacuum-desiccated and weighed again. This cleaning and weighing procedure was followed at the end of 4, 13, and 52 weeks.

Triplicate or duplicate samples were used for all materials. This enabled cleaning and inspection of some samples and saving others for continued testing. Corrosion rates were determined from weight-loss data. Weight-loss measurements were supplemented by x-ray analysis of corrosion products.

4.9.2.2 Results and Discussion

Detailed test results are presented in Tables 4.9-5 through 4.9-7. Results are available for carbon steel (1018), low alloy steel (4140), gray cast iron, and Ni-Resist Type 1 in all seven environments. Results for other alloys are available for nonaerated wet steam in Table 4.9-6 and aerated condensate in Table 4.9-7. These results and observations by Braithwaite and Kichti (1979) are discussed in some detail below.

Bore Fluid

The uniform (weight-loss) corrosion rate of carbon steel decreased with time. The rate was 1.62 mpy at 4 weeks and 0.138 mpy at 52 weeks. Pitting had begun by the fourth week and crevice corrosion by the thirteenth week. The attack was relatively (unquantified) shallow. The uniform corrosion rate of 4140 steel was 1.45 mpy at 4 weeks and 0.0756 mpy at one year. Crevice corrosion began during the first thirteen weeks. Pitting began later but was shallow (not quantified).

Gray cast iron was covered with adherent iron sulfide scale by the fourth week. Crevice corrosion was detected, but no pitting occurred. The uniform corrosion rate decreased sharply with time: 2.73 mpy at four weeks and 0.232 mpy at one year. The performance of Ni-Resist Type 1 was similar to that of carbon steel. The uniform corrosion rates were 0.850 mpy at 4 weeks and 0.079 mpy at one year. Crevice corrosion of mild but unquantified severity occurred.

Separated Water

Silica scaling reduced the corrosion rates in this environment. Silica was deposited at 2.5 mpy, and the rate was nearly constant with time. The uniform corrosion rate of carbon steel was lower than in bore fluid: 0.068 mpy at four weeks and 0.010 mpy at one year. No localized corrosion occurred. 4140 steel began to crevice corrode during the first four weeks. No pitting occurred during the test. The magnitude and change with time of the corrosion rate for this steel were very similar to carbon steel (0.067 mpy at four weeks and 0.010 mpy at one year).

TABLE 4.9-5. CORROSION TEST RESULTS IN BORE WATER AND SEPARATED WATER AT
BROADLANDS, NEW ZEALAND

MATERIAL TESTED	BORE FLUID				SEPARATED WATER			
	Uniform Corrosion (mpy) ^a	Pitting	Crevice Corrosion	SCC	Uniform Corrosion (mpy) ^a	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>								
Gray	.232	N	X	--	0.028	X	X	--
Ni-Resist Type 1	0.079	N	X	--	0.021	X	X	--
<u>Steels</u>								
Carbon (1018)	0.138	X	X	--	0.010	X	X	--
Cr-Mo (4140)	0.756	X	X	--	0.010	X	X	--

^a52 week exposure.

KEY TO TABLE

N - not detected

X - detected but not quantified

- - data not available

Source: Braithwaite and Kichti 1979

TABLE 4.9-6. CORROSION TEST RESULTS FOR STEAM ENVIRONMENTS AT BROADLANDS, NEW ZEALAND

MATERIALS TESTED	NONAERATED DRY STEAM				NONAERATED WET STEAM				AERATED WET STEAM			
	Uniform Corrosion (mpy) ^a	Pitting Rate (mpy) ^b	Crevice Corrosion (mpy) ^b	SCC	Uniform Corrosion (mpy) ^a	Pitting Rate (mpy) ^b	Crevice Corrosion (mpy) ^b	SCC	Uniform Corrosion (mpy) ^a	Pitting Rate (mpy) ^b	Crevice Corrosion (mpy) ^b	SCC
Cast Irons												
Gray	0.793	X	X	-	0.494	X	X	-	20.7	X	X	-
Ni-Resist Type 1	.140	N	X	-	0.112	X	X	-	26.1	X	X	-
Steels												
Carbon (1018)	0.678	7.1	X	-	0.673	X	X	-	37.9	158 ^c	X	-
Cr-Mo (4140)	1.185	X	X	-	0.901	X	X	-	33.9	X	X	-
Stainless Steels												
AISI 410	-	-	-	-	0.078	2.6	2.4	-	-	-	-	-
AISI 304	-	-	-	-	0.009	2.6	2.8	-	-	-	-	-
AISI 316	-	-	-	-	0.002	1.9	1.5	-	-	-	-	-
AISI 321	-	-	-	-	0.004	2.1	1.3	-	-	-	-	-
AISI 347	-	-	-	-	0.093	2.3	2.2	-	-	-	-	-
Sandvik 2RK65	-	-	-	-	0.001	2.2	1.6	-	-	-	-	-
Sandvik 3RE60	-	-	-	-	0.003	1.7	1.0	-	-	-	-	-
E-Brite 26-1	-	-	-	-	0.005	1.5	1.7	-	-	-	-	-
Carpenter 20Cb3	-	-	-	-	0.002	1.1	0.91	-	-	-	-	-
FV 520 (B)	-	-	-	-	0.012	2.0	0.04	-	-	-	-	-
Icoloy 825	-	-	-	-	0.001	1.9	0.83	-	-	-	-	-
Copper Alloys												
Deoxidized Copper	-	-	-	-	0.598	N	N	-	-	-	-	-
2Al-Brass	-	-	-	-	0.580	N	N	-	-	-	-	-
Titanium Alloys												
Titanium	-	-	-	-	0.003	N	N	-	-	-	-	-
Ti-6Al-4V (IMI 318)	-	-	-	-	0.003	N	N	-	-	-	-	-
Ti-4Al-4Mo (IMI 558)	-	-	-	-	0.003	N	N	-	-	-	-	-

^aBased on 52-week exposure.^bBased on depth of greatest attack after 52 weeks^cBased on maximum depth of attack at 13 weeks**KEY TO TABLE**

X - Detected but not quantified

N - Not detected

- - No data available

Source: Braithwaite and Kichti 1979

TABLE 4.9-7. CORROSION TEST RESULTS FOR CONDENSATE ENVIRONMENTS
AT BROADLANDS, NEW ZEALAND

MATERIALS TESTED	NONAERATED CONDENSATE				AERATED CONDENSATE			
	Uniform Corrosion (mpy) ^a	Pitting Rate (mpy) ^b	Crevice Corrosion (mpy)	SCC	Uniform Corrosion (mpy) ^a	Pitting Rate (mpy) ^b	Crevice Corrosion (mpy)	SCC
Cast Irons								
Gray	5.65	N	X	-	55.2	-	-	-
Ni-Resist Type 1	0.021	X	X	-	13.8	-	-	-
Steels								
Carbon (1018)	5.99	X	N	-	58.2	79	N	-
Cr-Mo (4140)	4.80	X	-	-	24.1	X	X	-
Stainless Steels								
AISI Type 410	-	-	-	-	0.195	39	-	-
AISI Type 304	-	-	-	-	0.001	-	-	-
AISI Type 316	-	-	-	-	<0.001	-	-	-
AISI Type 321	-	-	-	-	~0.001	-	-	-
AISI Type 347	-	-	-	-	~0.001	-	-	-
Sandvik 2RK65	-	-	-	-	<0.001	-	-	-
Sandvik 3RE60	-	-	-	-	~0.001	-	-	-
E-Brite 26-1	-	-	-	-	0.024	-	-	-
Carpenter 20Cb3	-	-	-	-	<0.001	-	-	-
FV 520 (B)	-	-	-	-	0.001	-	-	-
Incoloy 825	-	-	-	-	~0.001	-	-	-
Copper Alloys								
Deoxidized Copper	-	-	-	-	2.15	N	N	-
2Al-Brass	-	-	-	-	1.37	N	N	-
Titanium Alloys								
Titanium	-	-	-	-	<0.001	N	N	-
Ti-6Al-4V (IMI 318)	-	-	-	-	<0.001	N	N	-
Ti-4Al-4Mo (IMI 558)	-	-	-	-	<0.001	N	N	-

^aBased on 52-week exposure

^bMaximum depth after 13 weeks

KEY TO TABLE

N - indicated form of corrosion not detected

X - indicated form of corrosion detected

- - no data available

Source: Braithwaite and Kichti 1979

No pitting occurred in gray cast iron samples, but crevice corrosion of unspecified severity began during the first four weeks. Exfoliation of iron sulfide began after the thirteenth week. Ni-Resist Type 1 had similar resistance to localized attack. Exfoliation began sooner than for gray cast iron. The corrosion rate decreased from 0.202 mpy at 4 weeks to 0.023 mpy at one year.

Separated Dry Steam

The uniform corrosion rate of carbon steel was 4.79 mpy at four weeks. The rate decreased threefold by the thirteen week and was only 0.678 mpy after one year. Exfoliation of iron sulfide occurred. Pits 7.1 mils deep were observed after one year. Exfoliation of iron sulfide from 4140 steel was more severe than from carbon steel, and both pitting and crevice corrosion was initiated during the first four weeks. The corrosion rate dropped from 3.11 mpy at four weeks to 1.42 mpy at thirteen weeks. Little change occurred after that time. Crevice corrosion began during the first four weeks for both gray cast iron and Ni-Resist Type 1. Pitting of gray cast iron also began during this time, but Ni-Resist Type 1 did not pit during the test. The uniform corrosion rate of gray cast iron was 4.49 mpy at four weeks and 0.793 mpy at one year. Ni-Resist Type 1 performed better than carbon steel: its corrosion rates were 1.00 mpy at four weeks and 0.14 mpy at one year.

Wet Low Pressure Steam

The uniform corrosion rate of carbon steel was 1.06 mpy at four weeks and 0.673 mpy at one year. Extensive pitting (of unquantified depth) occurred after the thirteenth week. 4140 steel corroded at 0.789 mpy at 4 weeks and 0.901 mpy at one year. The adhesion of the iron sulfide corrosion product was poor. Pitting (unquantified) was observed after thirteen weeks, and crevice corrosion began after this length of time.

Both gray cast iron and Ni-Resist Type 1 performed fairly well in this environment. The corrosion rate for gray cast iron was 1.57 mpy at four weeks. It decreased by a factor of three by the end of one year. Ni-Resist Type 1 corroded at 0.313 mpy at four weeks and showed the same reduction with time. Pitting and crevice corrosion of both alloys began after the thirteenth week.

The stainless steels had corrosion rates of less than 0.1 mpy after one-year exposures. For all except AISI 410 and 347, the rate was less than 0.01 mpy. Pitting and crevice corrosion of all these alloys except AISI 410 began after the thirteenth week. Maximum pit depths after one year ranged from 1.1 to 2.6 mils. The pits were all less than 8.9 mils in diameter.

For AISI 304, the maximum penetration at one year was 2.6 mils. Pit density was greater than 46,000 pits/ft². Crevice corrosion depth was 2.8 mils at one year. Pit density of AISI 316 was 46,000 to 93,000 pits/ft². Maximum depth of pits at one year was 1.9 mils. Crevice attack was 1.5 mils at one year. Pitting density of AISI 321 was estimated at 93,000 pits/ft². Maximum depth was 2.1 mils at one year. Crevice corrosion was 1.3 mils at one year.

Pit density of AISI 347 was similar to AISI 321, but pits were deeper (2.3 mils at one year). Crevice corrosion of the same severity occurred. Carpenter 20Cb3 pitted to a depth of 2 mils at one year. Density was 230 pits/ft², a considerable improvement over the 300 series austenitic steels just discussed. Crevice attack was 0.9 mils at one year. Incoloy 825 pitted to 1.9 mils at one year. There were 4600 to 9300 pits/ft². Crevice depth was 0.8 mils. Sandvik 3RE60 pitted to 1.7 mils while Sandvik 2RK65 pitted to 2.2 mils. Pit density of 3RE60 was 9300 to 46,000 pits/ft². Crevice depths were 1.0 mil and 1.6 mils, respectively. C Drite 26-1 pitted to 1.5 mils at one year. Crevice depth was similar. Pit density was 9300 pits/ft².

AISI 410 and Firth-Vickers Alloy FV520 (B) were the only turbine blade alloys exposed. AISI 410 was the only stainless steel to pit prior to the thirteenth week. After one year, maximum pit depth was 2.6 mils, while maximum crevice depth was 2.4 mils. Density was greater than 46,000 pits/ft². Alloy FV520 (B) did not pit until after thirteen weeks exposure, but by the end of one year, it was equal to AISI 410 in terms of pit depth, pit density, and severity of crevice corrosion.

Copper (deoxidized) corroded at 0.598 mpy at one year. This was a fivefold increase compared to thirteen week results. No localized corrosion was reported.

The performance of 2Al-Brass was similar to that of copper. The corrosion rate at one year was 0.580 mpy with no localized corrosion. The corrosion rates of the three titanium alloys tested were all less than 0.01 mpy. No local attack occurred.

Aerated Wet Steam

The weight-loss corrosion rate of carbon steel was 37.9 mpy. This was largely due to the severe pitting: 39 mils at thirteen weeks (159 mpy extrapolated rate). Crevice attack of unspecified depth also occurred. 4140 steel corroded at 33.9 mpy (one year rate) with pitting and crevice corrosion of unspecified severity. Graphitic corrosion was observed on the two cast irons. The weight-loss corrosion rates of gray cast iron and Ni-Resist Type 1 were 20.7 mpy and 26.1 mpy, respectively, after one year. Both materials showed tenfold increases in their corrosion rate when four week and one year results were compared.

Condensate

The corrosion rate of carbon steel (5.99 mpy) was nearly constant during the test in nonaerated condensate. In aerated condensate the corrosion rate was 170 mpy at four weeks and 58 mpy at one year. Pitting was pronounced and was associated with hydrogen blistering. Pitting began earlier in nonaerated condensate.

The corrosion rate of 4140 steel decreased with time in both non-aerated and aerated condensate. In nonaerated condensate, the rate was 7.39 mpy at four weeks and 4.80 mpy at one year. Pitting was pronounced (unquantified) and followed grain orientation. In aerated condensate, the rate was 138 mpy at four weeks and 24.1 mpy at one year.

Gray cast iron and Ni-Resist Type 1 showed very good corrosion resistance in nonaerated condensate. The corrosion rate of gray cast iron decreased from 9.32 mpy at four weeks to 3.56 mpy at one year, while Ni-Resist Type 1 corroded at 0.127 mpy at four weeks and 0.021 mpy at one year. Slight (unquantified) local corrosion occurred. In aerated condensate, gray cast iron was destroyed by graphitization. After one year, there was no iron remaining in the matrix. Graphitic corrosion of Ni-Resist Type 1 was also evident after one year.

AISI 410 corroded at 0.195 mpy (one year rate) and had deep (unquantified) pits. E-Brite 26-1 had a low (0.02 mpy) corrosion rate but was badly corroded (unquantified) under the Teflon (TFE) crevice. Only uniform corrosion data are available for the other stainless steels. The corrosion rates were all 0.001 mpy or less at one year.

Deoxidized copper corroded uniformly at 2.2 mpy (one year rate). The rate decreased slightly more than twofold between four weeks and one year. The corrosion of 2Al-Brass was also uniform. The rate was 3.40 mpy at four weeks and 1.37 mpy at one year. The three titanium alloys had one year corrosion rates less than 0.001 mpy. The rates decreased at least tenfold, compared to four-week corrosion rates.

REFERENCES

- Braithwaite, W. R., and Kichti, K.A., April 1979. Surface corrosion of metals in geothermal fluids at Broadlands, New Zealand. Paper presented at the ACS/ASTM meeting, Honolulu, Hawaii.
- Ellis, A. J., and Mahon, W. A. J., 1977. Chemistry and Geothermal Systems. New York: Academic Press.
- Gilbert, P. T., 1956. Corrosion-Fatigue. Metall. Rev. 1:379-417.
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4.10 WAIRAKEI, NEW ZEALAND

The geothermal resource at Wairakei has been extensively developed, and three major long-term corrosion studies have been reported. This section briefly describes the Wairakei geothermal project and discusses the three tests and plant experience. The location of Wairakei is shown in Figure 4.10-1.

The Wairakei geothermal resource is liquid-dominated and is utilized by single flash recovery (bore flashing). Steel-cased bores 500 to 3980 feet deep tap geothermal fluid at temperatures up to 518°F. The major contaminants in the resource are carbon dioxide (90 to 8000 ppm), hydrogen sulfide (3 to 320 ppm), sodium chloride and potassium chloride (1000 to 2000 ppm), and silica (150 to 500 ppm). Many other constituents are minor contaminants. As the liquid phase rises up the bore, the pressure and temperature decrease, and the liquid flashes into a two-phase fluid. Steam and water are separated at the wellhead, and the water containing non-volatile contaminants and some noncondensable gases is disposed of. Steam, containing most of the noncondensables and less than one percent moisture (droplet carry-over) at 500 to 200 psig, passes through low pressure turbines. After the turbines, the steam (at about 104°F and one psia) is condensed by sprays of oxygen-saturated cold water in jet condensers and removed via a barometric seal. Noncondensable gases are removed by vacuum pumps (Foster, Marshall, and Tombs 1964).

4.10.1 Fluid Chemistry

Table 4.10-1 gives the key species chemistry of separated geothermal fluid from six wells at Wairakei while Table 4.10-2 gives analyses of steam. These fluids were separated at atmospheric pressure and boiling temperature. Table 4.10-3 is a computer reconstruction of the composition of the in-situ fluid at Hole 20.

4.10.2 Corrosion Tests

Two studies of common engineering materials were performed jointly by the New Zealand Ministry of Works and Department of Scientific Research. The International Nickel Company (INCO) also ran a series of tests. Tables 4.10-4, 4.10-5, and 4.10-6 are screening tables which summarize the results of these tests.

Methods

In all three tests, the uniform corrosion rate was determined by the ASTM 244 coupon method. The stress corrosion samples in the tests reported in Tables 4.10-7 to 4.10-14 were constant deformation strip specimens stressed beyond the yield point. No pitting information was

FIGURE 4.10-1. LOCATION OF WAIRAKEI GEOTHERMAL RESOURCE

TABLE 4.10-1. TYPICAL COMPOSITIONS OF SEPARATED GEOTHERMAL WATERS FROM WAIRAKEI WELLS (SEPARATED AT ATMOSPHERIC PRESSURE AND BOILING TEMPERATURE)

WELL	pH	CONCENTRATION (ppm)							Calcium Ion
		Chloride	Sulfate	Carbon Dioxide	Ammonia	Hydrogen Sulfide	Fluoride	Silica	
20	8.4	2215	35	17	.20	1.7	8.2	640	18
27	8.5	2156	25	23	.15	--	8.1	660	18
28	8.4	2170	27	31	.15	2	7.7	680	20
41	8.5	2113	23	20	.15	3	7.5	540	24
43	8.2	2106	22	16	.15	--	7.7	460	27
44	8.6	2260	36	19	.15	1.4	8.3	640	17

--: no data available

Source: Ellis and Mahon 1977

TABLE 4.10-2. GAS CONCENTRATIONS IN STEAM FROM SELECTED WELLS AT WAIRAKEI

WELLS	ppm (vol) in Steam			ppm (wt) in Steam		
	Carbon Dioxide	Hydrogen Sulfide	Ammonia	Carbon Dioxide	Hydrogen Sulfide	Ammonia
18	310	11	2	757	21	1.9
27	165	5.5	1.4	403	10	1.3
43	39	2	1.3	95	4	1.2
46	21	2.4	1.3	51	4.5	1.2
47	60	3.5	1.2	147	7	1.1
203	4180	92	5.3	10,150	174	5.0

Source: Ellis and Mahon 1977

TABLE 4.10-3. ANALYSIS OF AQUIFER FLUID ADJACENT TO HOLE 20 AT WAIRAKEI, NEW ZEALAND

COMPONENT ^a		CONCENTRATION
Key Species:	pH ^b	6.34
		<u>ppm</u>
	Chloride ion (Cl ⁻)	1520
	Sulfate ion (SO ₄ ²⁻)	7.6
	Carbon dioxide (CO ₂)	489
	Bicarbonate ion (HCO ₃ ⁻)	21
	Carbonate ion (CO ₃ ²⁻)	0
	Hydrogen sulfide (H ₂ S)	8.5
	Ammonium ion (NH ₄ ⁺)	0.2
Other Species:	Sodium ion (Na ⁺)	880
	Calcium ion (Ca ²⁺)	17
	Magnesium ion (Mg ²⁺)	0
	Silica (SiO ₂)	97

^a Temperature 475°F
Pressure 545.3 psia
Enthalpy 455 BTU/lb

^b Neutral pH at 475°F is 5.6

Source: Truesdell and Singers 1974

presented. In Tables 4.10-15 through 4.10-22, the stress corrosion specimens were U-bend strips stressed beyond the yield point and retained under stress with a bolt. No stress corrosion specimens were included in the INCO tests (Table 4.10-23). The specimens were exposed to geothermal media intended to span the range of conditions found at the Wairakei project.

TABLE 4.10-4. CORROSION SCREENING RESULTS FOR CAST IRONS, CASINGS, AND LOW ALLOY STEELS AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TEST STREAM							
	Bore Water 464°F	Bore Water 250°F	Separated Water 257°F	Steam <1% Moisture 284-374°F	Steam 10% Moisture 239-324°F	Aerated Steam ~221°F	Air-Free Condensate 68-241°F	Aerated Condensate ~140°F
<u>Cast Irons</u>								
Gray	----	B N --	B N --	----	B N --	C N --	B N --	D N --
3Ni	----	----	----	----	----	----	----	B N --
Ni-Si	----	B N --	----	A N --	----	A N --	----	----
Ni-resist	----	A N --	----	A N --	B N --	B N --	B N --	A N --
<u>Casings</u>								
API J55 {Rb 97}	A -- H	B -- N	A -- N	A -- N	B -- N	>B --	B -- N	>B --
API P110 {Rc 30}	----	----	----	----	----	----	----	----
API H40 {Rb 91}	----	B -- N	A --	A -- N	B -- N	>B -- N	B -- N	>B --
APS10M4 {Rb 70}	----	----	----	----	----	----	----	----
<u>Low Alloy Steels</u>								
Carbon {Rb 50-80}	A -- N	B N - N	A N - N	B N - N	B N - N	C N - N	B N - N	C X --
Mo {Rb 85}	----	----	----	----	----	----	----	----
Mn {Rc <22}	A --	B --	A --	B N --	B N - N	>B -- N	B N --	C --
Ni {Rb 87}	----	----	----	----	----	----	----	----
Cr-Mo {Rc >22}	----	----	----	----	----	----	----	----
Cr-Mo {Rc <22}	----	----	----	----	----	----	----	----
Mn-Mo {Rc 25-33}	----	----	----	----	----	----	----	----
Cr-V {Rc 48}	----	----	----	----	----	----	----	----

KEY TO TABLE

- A - Uniform corrosion rate <1.0 mpy
- B - Uniform corrosion rate >1.0 mpy but <10 mpy
- C - Uniform corrosion rate >10 mpy but <50 mpy
- D - Uniform corrosion rate >50 mpy
- N - Indicated form of corrosion not detected
- X - Indicated form of corrosion detected
- No data available

Refer to Tables 4.10-7 through 4.10-23 for more detailed information.

TABLE 4.10-5. CORROSION SCREENING RESULTS FOR STAINLESS STEELS AT
WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TEST STREAM							
	Bore Water 464°F	Bore Water 250°F	Separated Water 257°F	Steam <1% Moisture 284-374°F	Steam 10% Moisture 239-324°F	Aerated Steam ~221°F	Air-Free Condensate 68-241°F	Aerated Condensate ~140°F
AISI T409	- - - -	- - - -	- - - -	- - - -	- - - -	- - - -	A X - -	A X - -
T410	- - - -	- - - -	- - - -	- - - -	- - - -	- - - -	A X - -	A X - -
T430	- - - -	- - - -	- - - -	- - - -	- - - -	- - - -	A X - -	A X - -
13Cr {BHN 285}	A - - N	A X - -	A - - -	A X - X	A X - N	A X - X	A X - X	A X - X
{BHN 210}	A - - -	A X - -	A - - -	A X - -	A X - -	A X - -	A X - -	A X - -
{BHN 180}	A - - -	A X - -	A - - -	A X - N	A X - -	A X - -	A X - X	A X - -
{BHN 150}	A - - -	A X - -	A - - -	A X - N	A X - -	A X - N	A X - X	A X - -
{Rc 50}	- - - -	- - - -	- - - -	- - - X	- - - X	- - - X	- - - -	- - - -
{Rb 98}	- - - N	- - - -	- - - -	- - - N	- - - N	- - - N	- - - -	- - - -
{Rb 90}	A - - N	A - - -	A - - -	A - - N	A - - N	B - - N	B - - -	A - - -
{Rc 22}	A - - N	A - - -	A - - -	A - - X	A - - X	B - - X	B - - -	A - - -
{Rc 22}	A - - N	A - - -	A - - -	A - - N	A - - N	B - - N	B - - -	A - - -
Rex 326	- - - -	- - - -	- - - -	- - - N	- - - -	- - - N	- - - N	- - - -
35Ni-10Cr	- - - -	- - - -	- - - -	- - - N	- - - -	- - - X	- - - N	- - - -
AISI T304	- - - -	- - - -	- - - -	- - - -	A N - -	- - - -	A N - -	A N - -
T304 (sens)	- - - -	- - - -	- - - -	- - - -	- - - -	- - - -	A X - -	- - - -
T316	- - - -	- - - -	- - - -	- - - -	A N - -	- - - -	A N - -	A N - -
Carpenter 20Cb3	- - - -	- - - -	- - - -	- - - -	A N - -	- - - -	A N - -	A N - -
Incoloy 825	- - - -	- - - -	- - - -	- - - -	A N - -	- - - -	A N - -	- - - -
18Cr-8Ni	- - - -	A X - N	- - - -	A N - N	A N - N	A N - X	A N - N	A X - N
18Cr-8Ni-1Nb	- - - -	- - - -	- - - -	- - - N	- - - -	- - - N	- - - N	- - - -
18Cr-8Ni-3Mo	- - - -	A N - N	- - - -	A N - N	A N - N	A N - N	A N - N	A N - -
18Cr-12Ni-1Nb	- - - -	- - - -	- - - -	A N - N	A N - -	A N - N	A N - N	A N - -
18Cr-12Ni-2Mo	- - - -	- - - -	- - - -	- - - -	- - - N	- - - -	- - - -	- - - -

KEY TO TABLE

- A - Uniform corrosion rate <1.0 mpy
- B - Uniform corrosion rate >1.0 mpy but <10 mpy
- C - Uniform corrosion rate >10 mpy but <50 mpy
- D - Uniform corrosion rate <50 mpy
- N - Indicated form of corrosion not detected
- X - Indicated form of corrosion detected
- - No data available

Refer to Tables 4.10-7 through 4.10-23 for more detailed information.

TABLE 4.10-6. CORROSION SCREENING RESULTS FOR NICKEL-, COPPER-, AND OTHER BASED ALLOYS AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TEST STREAM							
	Bore Water 464°F	Bore Water 250°F	Separated Water 257°F	Steam <1% Moisture 284-374°F	Steam 10% Moisture 239-324°F	Aerated Steam ~221°F	Air-Free Condensate 68-241°F	Aerated Condensate ~140°F
<u>Nickel Base</u>								
Nickel	- - - -	B N - -	- - - -	A N - -	B N - -	B N - -	B N - -	- - - -
Monel 40C	B - - N	B N - -	B - - N	B N - N	B N - N	B N - N	C X - N	C N - N
K-Monel	- - - N	B N - -	- - - -	A N - -	A N - -	D N - -	- - - -	- - - -
Inconel 600	B - - N	A - - -	A - - N	A - - N	A N - N	>B - - N	A N - N	- - - -
Hastelloy F	- - - -	- - - -	- - - -	- - - -	A N - -	- - - -	A N - -	- - - -
<u>Copper Base</u>								
Copper	- - - N	B N - N	B - - -	B N - N	B N - N	C N - N	B N - N	C N - N
Be-Copper	- - - X	- - - -	- - - -	- - - X	- - - -	- - - -	- - - -	- - - -
Si-Bronze	- - - -	B N - N	- - - -	B N - X	- - - N	C N - N	- - - -	- - - -
P - Bronze	- - - -	B N - N	- - - -	B N - N	B - - N	B - - N	- - - -	- - - -
Al-Bronze	- - - -	- - - -	- - - -	B N - N	B N - N	>B N - X	B N - N	- - - -
1-Ni-5Al-Bronze	- - - -	- - - -	- - - -	- - - -	- - - -	- - - -	B X - -	A X - -
70-30 Brass	- - - N	- - - -	- - - N	- - - N	- - - N	- - - N	- - - N	- - - -
60-40 Brass	B - - X	B N - N	A - - -	A N - N	A N - N	C N - N	A N - N	C N - N
<u>Other Bases</u>								
Titanium	A - - N	A - - N	A - - N	A N - N	A - - N	A N - N	- - - N	- - - -
Ti-Al-V	- - - -	- - - -	- - - -	- - - -	- - - N	- - - N	- - - -	- - - -
Aluminum	D - - -	A X - -	- - - N	A X - N	A X - N	A X - N	A X - N	A X - -

KEY TO TABLE

A - Uniform corrosion rate ≤ 1.0 mpy
 B - Uniform corrosion rate > 1.0 mpy but < 10 mpy
 C - Uniform corrosion rate > 10 mpy but < 50 mpy
 D - Uniform corrosion rate < 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 - - No data available

Refer to Tables 4.10-7 through 4.10-23 for more detailed information.

TABLE 4.10-7. CORROSION RESULTS USING BORE WATER (464°F) AT
WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	BORE WATER AT 464°F ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
Ferrous Alloys						
Gray cast iron	---	---	1.0-10	---	---	---
Low Alloy Steels						
Bore casings	API/J55	B90-92	<1.0	---	---	N
	API/P110	C30-31	---	---	---	N
	API/OM4	B96-99	---	---	---	N
	API/B40	B68-72	---	---	---	N
Carbon steels	En3	B80	<1.0	---	---	N
	En2	B50	<1.0	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N ^h
	prop-2 ^e	B80	---	---	---	N ^h
C-Mn steels	En15A	C21-22	<1.0	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mn steels	En29B	C37-39	---	---	---	N
	En29B	C27-30	---	---	---	N
	En29B	C18-19	---	---	---	---
Cr-V steel	En47	C48	---	---	---	N
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	N ^h
	En16	C25-27	---	---	---	N
Ni steel	En37	B87	---	---	---	---
High Alloy Steels						
13 Cr	En56A	C30	<1.0	---	---	N
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	---
13Cr-3Mo	Exp ^f	C30	---	---	---	---
	Exp ^f	B98	---	---	---	N
17Cr	En60	B85-94	<1.0	---	---	N
17Cr-2Ni	En57	C78-82	<1.0	---	---	N
	En57	B93-C28	---	---	---	N
Austenitic SS	En58A, F, G, H, J	B70-90	---	---	---	N
Non-Ferrous Alloys						
Titanium	ICI/150	B93-98	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel		C25	---	---	---	N
Monel	B307:NA13	B65-69	1.0-10	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	1.0-10	---	---	N ^h
Copper	BS1038	B83	<1.0	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	X ^h
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B54	---	---	---	---
	AB1C-AB2C	B63	---	---	---	---
Phosphor-bronze	BS407/S	B93	---	---	---	---
Silicon-bronze	BS1948	B59	---	---	---	---
60-40 brass	BS1949	B49	1.0-10	---	---	N
70-30 brass	BS378	B50	---	---	---	X
Aluminum	Alcoa 3003	H55	failed ^g	---	---	---

^aEn specification from B.S. 970/En series

^bDuration of exposure: 63-68 days

^cUniform corrosion results are for materials unspecified as to Rockwell hardness

^dProprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^gWeight gain and internal attack

^hMicroscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-8. CORROSION RESULTS USING BORE WATER (122-212°F) AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	BORE WATER AT 122-212°F ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
Ferrous Alloys						
Gray cast iron	---	---	1.0-10	---	---	---
Low Alloy Steels						
Bore casings	API/J55	B90-92	1.0-10	---	---	N
	API/P110	C30-31	---	---	---	N
	API/QM4	B96-99	---	---	---	N
	API/B40	B68-72	1.0-10	---	---	N
Carbon steels	En3	B80	1.0-10	---	---	N ²
	En2	B50	1.0-10	---	---	N ²
C-Mn steels	prop-1 ^d	B95	---	---	---	N ²
	prop-2 ^e	B80	---	---	---	N ²
C-Mn steels	En15A	C21-22	1.0-10	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mo steels	En29B	C37-39	---	---	---	N
	En29B	C27-30	---	---	---	N
	En29B	C18-19	---	---	---	---
Cr-V steel	En47	C48	---	---	---	N
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	N ²
	En16	C25-27	---	---	---	N
Mn steel	En37	B87	---	---	---	---
High Alloy Steels						
13Cr	En56A	C30	<1.0	---	---	N
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	---
13Cr-2Mo	Exp ^f	C30	---	---	---	---
	Exp ^f	B98	---	---	---	N
17Cr	En60	B85-94	<1.0	---	---	N
17Cr-2Ni	En57	C28-42	<1.0	---	---	N
	En57	B93-C28	---	---	---	N
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	N
Non-Ferrous Alloys						
Titanium	ICI/150	B93-98	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel		C25	---	---	---	N
Monel	B307:NA13	B65-69	<1.0	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	<1.0	---	---	N ²
Copper	BS1038	E83	---	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	X ²
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B34	---	---	---	---
	AB1C-AB2C	B63	---	---	---	---
Phosphor-bronze	BS4077S	B93	---	---	---	---
Silicon-bronze	BS1948	B59	---	---	---	---
60-40 brass	BS1949	B49	<1.0	---	---	N
70-30 brass	BS378	B50	---	---	---	X
Aluminum	Alcoa 3003	H55	1.0-10	---	---	---

^a En specification from B.S. 970 - En series

^b Duration of exposure: 54-95 days

^c Uniform corrosion results are for materials unspecified as to Rockwell Hardness

^d Proprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^e Proprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^f Experimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

² Microscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-9. CORROSION RESULTS USING SEPARATED WATER (257°F)
AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	Separated Water at 257°F, 80 psig ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
<u>Ferrous Alloys</u>						
Gray cast iron	---	---	>10	---	---	---
<u>Low Alloy Steels</u>						
Bore casings	API/J55	B90-92	<1.0	---	---	N
	API/P110	C30-31	---	---	---	---
	APSIOM4	B96-99	---	---	---	---
Carbon steels	API/H40	B68-72	<1.0	---	---	---
	En3	B80	<1.0	---	---	M
	En2	B50	<1.0	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N
	prop-2 ^e	B80	---	---	---	N
C-Mn steels	En15A	C21-22	<1.0	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mo steels	En29B	C37-39	---	---	---	---
	En29B	C27-30	---	---	---	---
	En29B	C18-19	---	---	---	---
Cr-V-steel	En47	C48	---	---	---	X
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	---
Ni steel	En16	C25-27	---	---	---	---
	En37	B87	---	---	---	---
<u>High Alloy Steels</u>						
13Cr	En56A	C30	<1.0	---	---	N
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	---
13Cr-3Mo	Exp ^f	C30	---	---	---	---
	Exp ^g	B98	---	---	---	---
17Cr	En60	B85-94	<1.0	---	---	---
17Cr-2Ni	En57	C28-42	<1.0	---	---	N
	En57	B93-C28	---	---	---	N
Austenitic SS	En58A, F, G, H, J	B70-90	<1.0	---	---	N
<u>Non-Ferrous Alloys</u>						
Titanium	ICI/150	B93-98	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel		C25	---	---	---	---
Monel	B307:NA13	B65-69	1.0-10	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	<1.0	---	---	N
Copper	BS1038	E83	1.0-10	---	---	---
Be-Copper	ASTM/120-41T	C38	---	---	---	---
Al-bronze	ASTM/120-41T	B47	---	---	---	---
	BS1400	B54	---	---	---	---
	AB1C-AB2C	B63	---	---	---	---
Phosphor-bronze	BS407/5	B93	---	---	---	---
Silicon-bronze	D31940	B59	---	---	---	---
60-40 brass	BS1949	B49	<1.0	---	---	N
70-30 brass	BS378	B50	---	---	---	---
Aluminum	Alcoa 3003	H55	<1.0	---	---	N

^aEn specification from B.S. 970 - En series

^bDuration of exposure: 155 days

^cUniform corrosion results are for materials unspecified as to Rockwell Hardness

^dProprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^gMicroscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-10. CORROSION RESULTS USING SEPARATED STEAM (379°F, 180 PSIG)
AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	SEPARATED STEAM AT 379°F, 180 psig ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
<u>Ferrous Alloys</u>						
Gray cast iron	---	---	1.0-10	---	---	---
<u>Low Alloy Steels</u>						
Bore casings	API/J55	B90-92	<1.0	---	---	N
	API/P110	C30-31	---	---	---	---
	AP510M4	B96-99	---	---	---	N
Carbon steels	API/H40	B68-72	<1.0	---	---	N
	En3	B80	<1.0	---	---	N
	En2	B50	<1.0	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N
	prop-2 ^e	B80	---	---	---	N
C-Mn steels	En15A	C21-22	<1.0	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mo steels	En29B	C37-39	---	---	---	---
	En29B	C27-30	---	---	---	---
	En29B	C18-19	---	---	---	---
Cr-V steel	En47	C48	---	---	---	X
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	---
Ni steel	En16	C25-27	---	---	---	---
	En37	B87	---	---	---	N ^h
<u>High Alloy Steels</u>						
13Cr	En56A	C30	<1.0	---	---	X ^h
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	---
13Cr-3Mo	Exp ^f	C30	---	---	---	X
	Exp ^f	B98	---	---	---	N
17Cr	En60	B85-94	<1.0	---	---	N ^h
17Cr-2Ni	En57	C28-42	<1.0	---	---	X ^h
	En57	B93-C28	---	---	---	N ^h
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	N
<u>Non-Ferrous Alloys</u>						
Titanium	ICI/150	B93-98	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel	---	C25	---	---	---	---
Monel	B307:NA13	B65-69	1.0-10	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	<1.0	---	---	N
Copper	BS1038	E83	1.0-10	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	X ^h
	ASTM/120-41T	B47	---	---	---	N ^h
Al-bronze	BS1400	B54	---	---	---	---
	AB1C-AB2C	B63	---	---	---	---
Phosphor-bronze	BS407/S	B93	1.0-10	---	---	N ^h
Silicon-bronze	BS1948	B59	---	---	---	X ^h
60-40 brass	BS1494	B49	<1.0	---	---	N
70-30 brass	BS378	B50	---	---	---	N
Aluminum	Alcoa 3003	H55	failed ^g	---	---	N

^aEn specification from B.S. 970 - En series

^bDuration of exposure: 144 days, <1% moisture

^cUniform corrosion results are for materials unspecified as to Rockwell Hardness

^dProprietary steel: 0.20% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^gWeight gain and internal attack

^hMicroscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-11. CORROSION RESULTS USING SEPARATED STEAM (288-324°F, 40-80 PSIG) AT WAIRAKEI, NEW ZEALAND

SEPARATED STEAM AT 288-324°F, 40-80 psig ^b						
MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
Ferrous Alloy						
Gray cast iron	---	---	1.0-10	---	---	---
Low Alloy Steels						
Bore casings	API/J55	B90-92	1.0-10	---	---	N ^d
	API/P110	C30-31	---	---	---	N
	API/1084	B98-99	---	---	---	N
	API/B40	B68-72	1.0-10	---	---	N ^d
Carbon steels	En3	B80	1.0-10	---	---	N
	En2	B50	1.0-10	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N
	prop-2 ^e	B80	---	---	---	N
C-Mn steels	En15A	C21-22	1.0-10	---	---	N ^d
	En15A	C15	---	---	---	N ^d
	En5	B85	---	---	---	N
Cr-Mn steels	En29B	C37-39	---	---	---	X ^e
	En29B	C27-30	---	---	---	X ^e
	En29B	C18-19	---	---	---	N
Cr-V steel	En47	C48	---	---	---	---
Mn-Mo steels	En17	C53	---	---	---	N ^d
	En17	C30-33	---	---	---	N ^d
	En16	C28-30	---	---	---	X
	En16	C25-27	---	---	---	N
Ni steel	En37	B87	---	---	---	X
High Alloy Steels						
13Cr	En56A	C30	<1.0	---	---	N
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	N
13Cr-2Mo	Exp ^f	C30	---	---	---	X
	Exp ^f	B98	---	---	---	N
17Cr	En60	B85-94	<1.0	---	---	N
17Cr-2Ni	En57	C28-42	<1.0	---	---	X
	En57	B93-C28	---	---	---	N
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	N
Non-Ferrous Alloys						
Titanium	ICI/150	D93-90	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	N
K-Monel	---	C25	---	---	---	---
Monel	B307;NA13	B65-69	1.0-10	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	<1.0	---	---	N
Copper	BS1038	B83	1.0-10	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	---
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B34	1.0-10	---	---	N
	AB1C-AB2C	B63	1.0-10	---	---	N
Phosphor-bronze	BS407/S	B93	1.0-10	---	---	N
Silicon-bronze	BS1948	B59	---	---	---	N
60-40 brass	BS1949	B49	<1.0	---	---	N
70-30 brass	BS378	B50	---	---	---	---
Aluminum	Alcoa 3003	H55	<1.0	---	---	N

^aEn specification from B.S. 970 - En series

^bDuration of exposure: 144 days, 10% moisture

^cUniform corrosion results are for materials unspecified as to Rockwell Hardness

^dProprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^gMicroscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tomba 1964

TABLE 4.10-12. CORROSION RESULTS USING AERATED STEAM (208-226°F, 0-5 PSIG) AT WAIRAKEI, NEW ZEALAND

AERATED STEAM AT 208-226°F, 0-5 psig ^b						
MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
Ferrous Alloys						
Gray cast iron	---	---	>10	---	---	---
Low Alloy Steels						
Bore casings	API/J55	B90-92	>10	---	---	---
	API/P110	C30-31	---	---	---	N
	AP510M4	B96-99	---	---	---	N
	API/H40	B68-72	>10	---	---	N
Carbon steels	En3	B80	>10	---	---	N
	En2	B50	>10	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N
	prop-2 ^e	B80	---	---	---	N
C-Mn steels	En15A	C21-22	>10	---	---	N
	En15A	C15	---	---	---	N
	En5	B85	---	---	---	N
Cr-Mn steels	En29B	C37-39	---	---	---	N
	En29B	C27-30	---	---	---	N
	En29B	C18-19	---	---	---	N ^g
Cr-V steel	En47	C48	---	---	---	N ^g
Mn-Mo steels	En17	C53	---	---	---	N ^g
	En17	C30-33	---	---	---	N ^g
	En16	C28-30	---	---	---	N
	En16	C25-27	---	---	---	---
Ni steel	En37	B87	---	---	---	N
High Alloy Steels						
13Cr	En56A	C30	1.0-10	---	---	X
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	N
13Cr-3Mo	Exp ^f	C30	---	---	---	X
	Exp ^f	B98	---	---	---	N
17Cr	En60	B85-94	1.0-10	---	---	N
17Cr-2Ni	En57	C28-42	1.0-10	---	---	X
	En57	B93-C28	---	---	---	N
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	X
Non-Ferrous Alloys						
Titanium	ICI/150	B93-98	<1.0	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	N
K-Monel		C25	---	---	---	---
Monel	B307:NA13	B65-69	>10	---	---	N
Inconel 60C	ASTM/B168-41T	B68-77	>10	---	---	N
Copper	BS1038	B83	>10	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	---
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B54	>10	---	---	X
	AB1C-AB2C	B63	>10	---	---	N
Phosphor-bronze	BS407/S	B93	1.0-10	---	---	N
Silicon-bronze	BS1948	B59	---	---	---	N
60-40 brass	BS1949	B49	>10	---	---	N
70-30 brass	BS378	B50	---	---	---	---
Aluminum	Alcoa 3003	H55	<1.0	---	---	N

^a En specification from B.S. 970 - En series

^b Duration of exposure: 144 days

^c Uniform corrosion results are for materials unspecified as to Rockwell Hardness

^d Proprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^e Proprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^f Experimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^g Microscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-13. CORROSION RESULTS FOR NON-AERATED CONDENSATE (68-158°F, 0-180 PSIG) AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	NON-AERATED CONDENSATE ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
Ferrous Alloys						
Gray cast iron		---	---	---	---	---
Low Alloy Steels						
Bore casings	API/J55	B90-92	1.0-10	---	---	N ^g
	API/P110	C30-31	---	---	---	X ^g
	API/10M4	B96-99	---	---	---	N ^g
	API/H40	B68-72	1.0-10	---	---	N ^g
Carbon steels	En3	B80	1.0-10	---	---	N
	En2	B50	1.0-10	---	---	N
C-Mn steels	prop-1 ^d	B95	---	---	---	N
	prop-2 ^e	B80	---	---	---	N
C-Mn steels	En15A	C21-22	1.0-10	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mo steels	En29B	C37-39	---	---	---	X
	En29B	C27-30	---	---	---	---
	En29B	C18-19	---	---	---	---
Cr-V steel	En47	C48	---	---	---	---
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	N
	En16	C25-27	---	---	---	---
Ni steel	En37	B87	---	---	---	---
High Alloy Steels						
13Cr	En56A	C30	1.0-10	---	---	X
	En56A	B60-90	---	---	---	N
	En56C	C12-28	---	---	---	---
13Cr-3Mo	Exp ^f	C30	---	---	---	---
	Exp ^f	B98	---	---	---	---
17Cr	En60	B85-94	1.0-10	---	---	---
17Cr-2Ni	En57	C10-42	1.0-10	---	---	---
	En57	B93-C28	---	---	---	---
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	N
Non-Ferrous Alloys						
Titanium	ICI/150	B93-98	---	---	---	N
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel		C15	---	---	---	---
Monel	B307:NA13	B65-69	1.0-10	---	---	N
Inconel 600	ASTM/B168-41T	B68-77	---	---	---	---
Copper	BS1038	E83	1.0-10	---	---	N
Be-Copper	ASTM/120-41T	C38	---	---	---	---
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B54	1.0-10	---	---	N
	AB1C-AB2C	B63	1.0-10	---	---	N
Phosphor-bronze	BS407/S	B93	---	---	---	---
Dillicon-bronze	B619/8	B59	---	---	---	---
60-40 brass	BS1949	B49	---	---	---	N
70-30 brass	BS378	B50	---	---	---	---
Aluminum	Alcoa 3003	H55	<1.0	---	---	N

^aEn specification from B.S. 970 - En series

^bDuration of exposure: 60-122 days

^cUniform corrosion results are for materials unspecified as to Rockwell hardness

^dProprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

^gMicroscopic surface fissures detected by metallographic examination

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-14. CORROSION RESULTS FOR AERATED CONDENSATE (68-158°F, 0-180 PSIG) AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	EQUIVALENT SPECIFICATION ^a	ROCKWELL HARDNESS	AERATED CONDENSATE ^b			
			Uniform Corrosion ^c (mpy)	Pitting	Crevice Corrosion	SCC
<u>Ferrous Alloys</u>						
Gray cast iron		---	>10	---	---	---
<u>Low Alloy Steels</u>						
Bore casings	API/J55	B90-92	>10	---	---	---
	API/P110	C30-31	---	---	---	---
	API/10M4	B96-99	---	---	---	---
Carbon steels	API/H40	B68-72	>10	---	---	---
	En3	B80	>10	---	---	---
	En2	B50	>10	---	---	---
C-Mn steels	prop-1 ^d	B95	---	---	---	---
	prop-2 ^e	B80	---	---	---	---
C-Mn steels	En15A	C21-22	>10	---	---	---
	En15A	C15	---	---	---	---
	En5	B85	---	---	---	---
Cr-Mo steels	En29B	C37-39	---	---	---	---
	En29B	C27-30	---	---	---	---
	En29B	C18-19	---	---	---	---
Cr-V steel	En47	C48	---	---	---	---
Mn-Mo steels	En17	C53	---	---	---	---
	En17	C30-33	---	---	---	---
	En16	C28-30	---	---	---	---
Ni steel	En16	C25-27	---	---	---	---
	En37	B87	---	---	---	---
<u>High Alloy Steels</u>						
13Cr	En56A	C30	<1.0	---	---	---
	En56A	B60-90	---	---	---	---
	En56C	C12-28	---	---	---	---
13Cr-3Mo	Exp ^f	C30	---	---	---	---
	Exp ^g	B98	---	---	---	---
17Cr	En60	B85-94	<1.0	---	---	---
17Cr-2Ni	En57	C28-42	<1.0	---	---	---
	En57	B93-C28	---	---	---	---
Austenitic SS	En58A,F,G,H,J	B70-90	<1.0	---	---	---
<u>Non-Ferrous Alloys</u>						
Titanium	ICI/150	B93-98	---	---	---	---
Ti-Al-V	ICI/318A	C33	---	---	---	---
K-Monel		C25	---	---	---	---
Monel	B307:NA13	B65-69	---	---	---	---
Inconel 600	ASTM/B168-41T	B68-77	---	---	---	---
Copper	BS1038	E83	---	---	---	---
Be-Copper	ASTM/120-41T	C38	---	---	---	---
	ASTM/120-41T	B47	---	---	---	---
Al-bronze	BS1400	B54	---	---	---	---
	AB1C-AB2C	B63	---	---	---	---
Phosphor-bronze	BS407/S	B93	---	---	---	---
Silicon-bronze	BS1948	B59	---	---	---	---
60-40 brass	BS1949	B49	---	---	---	---
70-30 brass	BS378	B50	---	---	---	---
Aluminum	Alcoa 3003	H55	---	---	---	---

^aEn specification from B.S. 970 - En series

^bDuration of exposure: 67 days

^cUniform corrosion results are for materials unspecified as to Rockwell Hardness

^dProprietary steel: 0.28% C, 1.25% Mn, 0.40% Mo

^eProprietary steel: 0.18% C, 0.7% Mn, 0.66% Mo

^fExperimental steel: 0.12% C, 12.5% Cr, 3.1% Mo

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Foster, Marshall, and Tombs 1964

TABLE 4.10-15. CORROSION RESULTS USING BORE DISCHARGE FLUID AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	BORE DISCHARGE FLUID ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron Base</u>					
Carbon steel	60-64	2	N	---	0/1
Carbon-Mn steel	74	---	---	---	---
Carbon-Mn steel	140	---	---	---	---
Mn-Mo steel	90	---	---	---	---
Cr-Mo steel	130	---	---	---	---
Ni steel	80	---	---	---	---
13Cr ^d	90	0.3	X	---	2/3
13Cr ^e	---	---	---	---	---
13Cr ^f	60	---	---	---	---
13Cr ^g	60	---	---	---	0/1
18Cr-8Ni	80	N	X	---	0/1
18Cr-8Ni-1Mo	82	---	---	---	---
18Cr-8Ni-1Mo	80-92	N	N	---	0/1
18Cr-12Ni-1Mo	82	---	---	---	---
18Cr-12Ni-2Mo	80	---	---	---	---
Rex 326	90	---	---	---	---
35Ni-10Cr	---	---	---	---	---
Gray cast iron	---	2	N	---	---
Ni-Silicon cast iron	---	2	N	---	---
Ni-resist cast iron	---	1	N	---	---
<u>Copper Base</u>					
Copper	32	8	N	---	0/1
Silicon-bronze	50	10	N	---	0/1
Phosphor-bronze	80	6	N	---	0/1
Aluminum-bronze (cast)	60	---	---	---	---
60-40 brass	32	4	N	---	0/2
<u>Nickel Base</u>					
Nickel	50	2	N	---	---
Monel	60	3	N	---	0/1
Inconel	70	2	N	---	0/1
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	N	X	---	0/1
Titanium	100	---	---	---	---
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	---	---	---	---
Chrome plate (6 mil)	---	0.2	N	---	---
Galvanized (1.5 mil)	---	0.2	X	---	---

^a Bore discharge fluid composition (250°F, 15 psig):

Component	Steam Phase (ppm)	Water Phase (ppm)
CO ₂	5400	5
H ₂ S	140	0.5
NH ₃	15	3
Boric acid	0.6	160
F ⁻	0.03	6
Cl ⁻	none	1500
Na ⁺	none	400
SiO ₂	none	300

^b Uniform corrosion results are for materials unspecified as to Brinell hardness

^c Reported as no. failures/no. samples tested

^d Brinell hardness 195-225 (machined from turbine blade)

^e Brinell hardness 285 (tempered 842°F)

^f Brinell hardness 180 (tempered 1382°F)

^g Brinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Hugill 1957

TABLE 4.10-16. CORROSION RESULTS USING SEPARATED STEAM AT
WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	SEPARATED STEAM ^a				
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c	Erosion (mpy)
<u>Iron Base</u>						
Carbon steel	60-64	6	N	---	0/4	11
Carbon-Mo steel	74	---	---	---	0/2	7
Carbon-Mn steel	140	2	N	---	---	---
Mn-Mo steel	90	---	---	---	2/2	11
Cr-Mo steel	130	---	---	---	2/2	7
Ni steel	80	---	---	---	2/2	---
13Cr ^d	90	0.3	X	---	0/7	---
13Cr ^e	---	---	---	---	0/4	---
13Cr ^f	60	---	---	---	0/2	<3.5
13Cr ^g	60	---	---	---	0/4	---
18Cr-8Ni	80	N	N	---	0/3	<3.5
18Cr-8Ni-1Mo	82	---	---	---	0/2	---
18Cr-8Ni-3Mo	30-92	N	N	---	0/4	<3.5
18Cr-12Ni-1Mo	82	N	N	---	0/2	<3.5
18Cr-12Ni-2Mo	80	---	---	---	0/1	---
Rex 326	90	---	---	---	0/2	<3.5
35Ni-10Cr	---	---	---	---	0/2	<3.5
Gray cast iron	---	3	N	---	---	---
Ni-Silicon cast iron	---	0.5	N	---	---	---
Ni-resist cast iron	---	1	N	---	---	---
<u>Copper Base</u>						
Copper	32	2	N	---	0/2	---
Silicon-bronze	50	3	N	---	0/1	---
Phosphor-bronze	80	2	N	---	0/1	---
Aluminum-bronze (cast)	60	3	N	---	0/1	---
60-40 brass	32	0.4	N	---	0/2	---
<u>Nickel Base</u>						
Nickel	50	1	N	---	---	---
Monel	60	4	N	---	0/2	---
Inconel	70	N	N	---	0/2	---
<u>Other Bases</u>						
Aluminum (Alcoa 35)	14	N	X	---	0/2	---
Titanium	100	N	N	---	0/3	---
<u>Plated Steel</u>						
Nickel plate (10 mil)	---	1	N	---	---	---
Chrome plate (6 mil)	---	N	N	---	---	---
Galvanized (1.5 mil)	---	N	X	---	---	---

^aFor corrosion results: 286°F, 40 psig

For erosion results: 293-298°F, 60-70 psia, 500-600 fps

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples treated

^dBrinell hardness 195-225 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Huggill 1957

TABLE 4.10-17. CORROSION RESULTS USING EXPANDED STEAM AT WAIRAKEI,
NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	EXPANDED STEAM ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron Base</u>					
Carbon steel	60-64	2	N	---	0/1
Carbon-Mo steel	74	---	---	---	---
Carbon-Mn steel	140	1	N	---	---
Mn-Mo steel	90	---	---	---	---
Cr-Mo steel	130	---	---	---	---
Ni steel	80	---	---	---	---
13Cr ^d	90	0.1	X	---	0/2
13Cr ^e	---	---	---	---	---
13Cr ^f	60	---	---	---	---
13Cr ^g	60	---	---	---	---
18Cr-8Ni	80	N	N	---	0/2
18Cr-8Ni-1Mo	82	---	---	---	---
18Cr-8Ni-3Mo	80-92	N	N	---	0/1
18Cr-12Ni-1Mo	82	N	N	---	---
18Cr-12Ni-2Mo	80	---	---	---	0/1
Rex 326	90	---	---	---	---
35Ni-10Cr	---	---	---	---	---
Gray cast iron	---	---	---	---	---
Ni-Silicon cast iron	---	---	---	---	---
Ni-resist cast iron	---	---	---	---	---
<u>Copper Base</u>					
Copper	32	1	N	---	0/1
Silicon-bronze	50	---	---	---	---
Phosphor-bronze	80	---	---	---	---
Aluminum-bronze (cast)	60	0.7	N	---	0/1
60-40 brass	32	0.2	N	---	0/1
<u>Nickel Base</u>					
Nickel	50	---	---	---	---
Monel	60	0.5	N	---	0/1
Inconel	70	---	---	---	---
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	N	X	---	0/1
Titanium	100	N	N	---	0/1
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	0.1	N	---	---
Chrome plate (6 mil)	---	---	---	---	---
Galvanized (1.5 mil)	---	---	---	---	---

^a 212°F, 1.5° superheat, 0 psig

^b Uniform corrosion results are for materials unspecified as to Brinell hardness

^c Reported as no. failures/no. samples tested

^d Brinell hardness 195-225 (machined from turbine blade)

^e Brinell hardness 285 (tempered 842°F)

^f Brinell hardness 180 (tempered 1382°F)

^g Brinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Huggill 1957

TABLE 4.10-18. CORROSION RESULTS USING WET SEPARATED STEAM AT
WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	WET SEPARATED STEAM ^a				
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c	Erosion (mpy)
<u>Iron Base</u>						
Carbon steel	60-64	5	N	---	0/1	113
Carbon-Mo steel	74	---	---	---	---	73
Carbon-Mn steel	140	4	N	---	---	---
Mn-Mo steel	90	---	---	---	---	77
Cr-Mo steel	130	---	---	---	---	44
Ni steel	80	---	---	---	---	---
13Cr ^d	90	0.1	X	---	0/3	---
13Cr ^e	---	---	---	---	---	---
13Cr ^f	60	---	---	---	---	7
13Cr ^g	60	---	---	---	---	---
18Cr-8Ni	80	N	N	---	0/2	4
18Cr-8Ni-1Mo	82	---	---	---	---	---
18Cr-8Ni-3Mo	80-92	N	N	---	0/1	<3.5
18Cr-12Ni-1Mo	82	N	N	---	---	<3.5
18Cr-12Ni-2Mo	80	---	---	---	0/1	---
Rex 326	90	---	---	---	---	<3.5
35Ni-10Cr	---	---	---	---	---	11
Gray cast iron	---	---	---	---	---	---
Ni-Silicon cast iron	---	---	---	---	---	---
Ni-resist cast iron	---	---	---	---	---	---
<u>Copper Base</u>						
Copper	32	3	N	---	0/1	---
Silicon-bronze	50	---	---	---	---	---
Phosphor-bronze	80	---	---	---	---	---
Aluminum-bronze (cast)	60	3	N	---	0/1	---
60-40 brass	32	0.8	N	---	0/1	---
<u>Nickel</u>						
Nickel	50	---	---	---	---	---
Monel	60	1	N	---	0/1	---
Inconel	70	N	N	---	0/1	---
<u>Nickel Base</u>						
Aluminum (Alcoa 35)	14	N	X	---	0/1	---
Titanium	100	---	---	---	---	---
<u>Plated Steel</u>						
Nickel plate (10 mil)	---	1	N	---	---	---
Chrome plate (6 mil)	---	N	N	---	---	---
Galvanized (1.5 mil)	---	---	---	---	---	---

^aFor corrosion results: 239°F, 10 psig, 10% moisture

For erosion results: 212-230°F, 15-20 psia, 9% moisture, 850-1050 fps

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples tested

^dBrinell hardness 195-225 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Hugill 1957

TABLE 4.10-19. CORROSION RESULTS USING GAS-FREE CONDENSATE AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	GAS-FREE CONDENSATE ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron Base</u>					
Carbon steel	60-64	0.4	N	---	0/1
Carbon-Mo steel	74	---	---	---	---
Carbon-Mn steel	140	---	---	---	---
Mn-Mo steel	90	---	---	---	---
Cr-Mo steel	130	---	---	---	---
Ni steel	80	---	---	---	---
13Cr ^d	90	---	---	---	---
13Cr ^e	---	---	---	---	---
13Cr ^f	60	---	---	---	---
13Cr ^g	60	---	---	---	---
18Cr-8Ni	80	N	N	---	0/1
18Cr-8Ni-1Mo	82	---	---	---	---
18Cr-8Ni-3Mo	80-92	N	N	---	0/1
18Cr-12Ni-1Mo	82	N	N	---	---
18Cr-12Ni-2Mo	80	---	---	---	---
Rex 326	90	---	---	---	---
35Ni-10Cr	---	---	---	---	---
Gray cast iron	---	---	---	---	---
Ni-Silicon cast iron	---	---	---	---	---
Ni-resist cast iron	---	---	---	---	---
<u>Copper Base</u>					
Copper	32	0.1	N	---	0/1
Silicon-bronze	50	---	---	---	0/1
Phosphor-bronze	80	---	---	---	0/1
Aluminum-bronze (cast)	60	---	---	---	---
60-40 brass	32	N	N	---	0/1
<u>Nickel Base</u>					
Nickel	50	0.1	N	---	---
Monel	60	0.1	N	---	0/1
Inconel	70	---	---	---	---
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	N	X	---	0/1
Titanium	100	---	---	---	---
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	---	---	---	---
Chrome plate (6 mil)	---	---	---	---	---
Galvanized (1.5 mil)	---	0.1	X	---	---

^a212°F, pH 6, H₂S <1 ppm, CO₂ <1 ppm

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples tested

^dBrinell hardness 195-225 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Hugill 1957

TABLE 4.10-20. CORROSION RESULTS USING GAS-RICH CONDENSATE IN
WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	GAS-RICH CONDENSATE ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron-Based</u>					
Carbon steel	60-64	3	N	---	0/1
Carbon-Mo steel	74	---	---	---	0/2
Carbon-Mn steel	140	3	N	---	---
Mn-Mo steel	90	---	---	---	0/2
Cr-Mo steel	130	---	---	---	2/2
Ni steel	80	---	---	---	---
13Cr ^d	90	0.1	X	---	2/6
13Cr ^e	---	---	---	---	2/2
13Cr ^f	60	---	---	---	0/2
13Cr ^g	60	---	---	---	0/3
18Cr-8Ni	80	N	N	---	0/2
18Cr-8Ni-1Mo	82	---	---	---	0/2
18Cr-8Ni-3Mo	80-92	N	N	---	0/3
18Cr-12Ni-1Mo	82	N	N	---	0/2
18Cr-12Ni-2Mo	80	---	---	---	---
Rex 326	90	---	---	---	0/2
35Ni-10Cr	---	---	---	---	0/2
Gray cast iron	---	---	---	---	---
Ni-Silicon cast iron	---	---	---	---	---
Ni-resist cast iron	---	---	---	---	---
<u>Copper Base</u>					
Copper	32	5	N	---	0/1
Silicon-bronze	50	---	---	---	---
Phosphor-bronze	80	---	---	---	---
Aluminum-bronze (cast)	60	1	N	---	0/1
60-40 brass	32	0.2	N	---	0/1
<u>Nickel Base</u>					
Nickel	50	---	---	---	---
Monel	60	4	N	---	0/1
Inconel	70	---	---	---	---
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	N	X	---	0/1
Titanium	100	---	---	---	0/2
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	2	N	---	---
Chrome plate (6 mil)	---	---	---	---	---
Galvanized (1.5 mil)	---	---	---	---	---

^a160°F, pH 6, 30 ppm H₂S, 400 ppm CO₂

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples tested

^dBrinell hardness 195-225 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Huggill 1957

TABLE 4.10-21. CORROSION RESULTS USING AERATED STEAM AT WAIRAKEI,
NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	AERATED STEAM ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron-Based</u>					
Carbon steel	60-64	20	N	---	0/4
Carbon-Mn steel	74	---	---	---	0/2
Carbon-Mn steel	140	---	---	---	---
Mn-Mo steel	90	---	---	---	0/2
Cr-Mo steel	130	---	---	---	---
Ni steel	80	---	---	---	0/1
13Cr ^d	90	1.0	X	---	3/5
13Cr ^e	---	---	---	---	---
13Cr ^f	60	---	---	---	0/2
13Cr ^g	60	---	---	---	0/1
18Cr-8Ni	80	N	N	---	2/3
18Cr-8Ni-1Mo	82	---	---	---	0/2
18Cr-8Ni-3Mo	80-92	N	N	---	0/4
18Cr-12Ni-1Mo	82	N	N	---	0/2
18Cr-12Ni-2Mo	80	---	---	---	---
Rex 326	90	---	---	---	0/2
35Ni-10Cr	---	---	---	---	2/2
Gray cast iron	---	10	N	---	---
Ni-Silicon cast iron	---	1	N	---	---
Ni-resist cast iron	---	10	N	---	---
<u>Copper Base</u>					
Copper	32	40	N	---	0/2
Silicon-bronze	50	20	N	---	---
Phosphor-bronze	80	9	N	---	---
Aluminum-bronze (cast)	60	10	N	---	1/1
60-40 brass	32	40	N	---	0/1
<u>Nickel Base</u>					
Nickel	50	8	N	---	---
Monel	60	10	N	---	0/2
Inconel	70	80	N	---	0/2
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	N	X	---	0/2
Titanium	100	N	N	---	0/3
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	X ^h	---	---	---
Chrome plate (6 mil)	---	N ^h	N	---	---
Galvanized (1.5 mil)	---	X ^h	---	---	---

^a221°F, 15,000 ppm O₂

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples tested

^dBrinell hardness 195-225 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Huggill 1957

TABLE 4.10-22. CORROSION RESULTS USING AERATED CONDENSATE AT WAIRAKEI,
NEW ZEALAND

MATERIAL TESTED	TENSILE STRENGTH (ksi)	AERATED CONDENSATE ^a			
		Uniform Corrosion ^b (mpy)	Pitting	Crevice Corrosion	SCC ^c
<u>Iron Base</u>					
Carbon steel	60-64	30	N	---	0/1
Carbon-Mo steel	74	---	---	---	---
Carbon-Mn steel	140	40	N	---	---
Mn-Mo steel	90	---	---	---	---
Cr-Mo steel	130	---	---	---	---
Ni steel	80	---	---	---	---
13Cr ^e	90	0.9	X	---	2/2
13Cr ^f	---	---	---	---	---
13Cr ^g	60	---	---	---	---
13Cr ^h	60	---	---	---	0/1
18Cr-8Ni	80	N	N	---	0/2
18Cr-8Ni-1Mo	82	---	---	---	---
18Cr-8Ni-3Mo	80-92	N	N	---	0/1
18Cr-12Ni-1Mo	82	N	N	---	---
18Cr-12Ni-2Mo	80	---	---	---	---
Rex 326	90	---	---	---	---
35Ni-10Cr	---	---	---	---	---
Gray cast iron	---	90	N	---	---
Ni-Silicon cast iron	---	---	---	---	---
Ni-resist cast iron	---	---	---	---	---
<u>Copper Base</u>					
Copper	32	40	N	---	0/1
Silicon-bronze	50	---	---	---	---
Phosphor-bronze	80	---	---	---	---
Aluminum-bronze (cast)	60	---	---	---	---
60-40 brass	32	40	N	---	0/1
<u>Nickel Base</u>					
Nickel	50	---	---	---	---
Monel	60	20	N	---	0/1
Inconel	70	---	---	---	---
<u>Other Bases</u>					
Aluminum (Alcoa 35)	14	0.2	X	---	0/1
Titanium	100	---	---	---	---
<u>Plated Steel</u>					
Nickel plate (10 mil)	---	30	N	---	---
Chrome plate (6 mil)	---	---	---	---	---
Galvanized (1.5 mil)	---	X ^h	---	---	---

^a140°F, 20 ppm H₂S, 25 ppm CO₂

^bUniform corrosion results are for materials unspecified as to Brinell hardness

^cReported as no. failures/no. samples tested

^dBrinell hardness 195-275 (machined from turbine blade)

^eBrinell hardness 285 (tempered 842°F)

^fBrinell hardness 180 (tempered 1382°F)

^gBrinell hardness 150 (annealed)

^hPlating destroyed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

--- Data not available

Source: Marshall and Huggill 1957

TABLE 4.10-23. INTERNATIONAL NICKEL COMPANY CORROSION TESTS AT WAIRAKEI, NEW ZEALAND

MATERIAL TESTED	TEST STREAM							
	Non-Aerated Steam ^a		Non-Aerated Condensate ^b		Aerated Condensate ^c		Turbine Discharge ^d	
	General Corrosion (mpy)	Growth of Deepest Pit (mpy)	General Corrosion (mpy)	Growth of Deepest Pit (mpy)	General Corrosion (mpy)	Growth of Deepest Pit (mpy)	General Corrosion (mpy)	Growth of Deepest Pit (mpy)
<u>Iron base</u>								
Cast iron	2.9	no pits	2.7	no pits	8.0	no pits	8.9	no pits
Mild steel	3.8	no pits	5.5	no pits	14.3	—	10.5	29.7
3Ni cast iron	—	—	—	—	8.4	no pits	8.9	no pits
Type 2 Ni-resist	2.4	no pits	3.8	no pits	0.9	4.6	4.6	no pits
AISI Type 304	<0.1	no pits	<0.1	no pits	<0.1	no pits	<0.1	no pits
AISI Type 304 ^f	—	—	—	—	—	—	<0.1	6.0
AISI Type 316	<0.1	no pits	<0.1	no pits	<0.1	no pits	<0.1	no pits
AISI Type 409(MF-1)	—	—	—	—	0.2	29.8	1.6	29.7
AISI Type 410	1.3	no pits	0.6	no pits	0.1	23.8	0.5	23.8
AISI Type 430	—	—	—	—	0.3	20.5	0.1	20.5
ACI CF-8	—	—	—	—	<0.1	—	<0.1	no pits
ACI CF-8M	—	—	—	—	<0.1	no pits	<0.1	no pits
Carpenter Alloy 20Cb3	<0.1	no pits	<0.1	no pits	<0.1	no pits	<0.1	no pits
<u>Nickel base</u>								
Nickel	2.8	no pits	2.3	no pits	—	—	—	—
Monel 400	5.2	no pits	5.0	no pits	—	—	10.8	29.8
Inconel	0.1	no pits	0.1	no pits	—	—	—	—
Ni-o-nel	<0.1	no pits	<0.1	no pits	—	—	—	—
Hastelloy F	<0.1	no pits	<0.1	no pits	—	—	—	—
<u>Copper base</u>								
10Ni-5Al-bronze	—	—	—	—	0.1	4.0	1.7	29.8

^a Field spool test holder in geothermal steam line. Temperature = 297 F-307°F. Steam contains 1 percent noncondensable gases (H₂S, CO₂, CH₄).

^b Temperature = 241°F, pH = 5.25. Contains CO₂, H₂S and NH₃.

^c Temperature = 122°F, pH = 7.8, HCO₃ = 662 ppm, NH₃ = 216 ppm, NO₃ < 1 ppm, SO₄ = 159 ppm, Cl = 7 ppm, B = 18 ppm, free S = 13 ppm, TDS = 119 ppm.

^d Field spool holder between turbine and barometric condenser. Temperature = 126°F.

^e Growth of deepest pit based on depth of maximum pit after 552 days exposure.

^f Sensitized

—: Data not available

Source: Banning and Oden 1973

Results and Discussion

Detailed results are shown in Table 4.10-7 through 4.10-23.

Uniform Corrosion

Because of chemical impurities, particularly chlorides, hydrogen sulfide, and carbon dioxide in geothermal steam, corrosion rates of common engineering alloys were usually higher than those encountered under similar conditions of temperature and pressure in clean boiler plant steam. Corrosion of most common engineering alloys in air-free geothermal media, with the exception of some copper alloys, was low enough to insure adequate service life. Mild steel was adequate for air-free service if a moderate corrosion allowance was made.

Aeration of geothermal media drastically increased (tenfold or more) the corrosion of most engineering alloys with the exception of austenitic stainless steels (especially those containing molybdenum), titanium, and chromium-plated steels. Galvanizing was unsuccessful in aerated geothermal media. Corrosion rates of most alloys in bore water at 482°F were low compared to those in lower temperature media. Pitting was characteristically absent in bore water at 482°F.

Empirical tests at Wairakei indicated that the following steels have sufficient resistance to erosion-corrosion by water droplets in steam (containing 9 percent moisture) at 900 feet per second (exhaust-end blading environment) to serve as turbine blading: 13 Cr, 18/8/1 Cr-Ni-Cb, 18/12/1 Cr-Ni-Cb, 18/8/3 Cr-Ni-Mo, Rex 326, and 35/10 Ni-Cr. Erosion-corrosion resistance was directly related to static corrosion resistance and not to hardness (Marshall and Hugill 1957).

Tests indicate that even under conditions of high stress, austenitic stainless steels were not susceptible to chloride stress corrosion cracking (SCC) in oxygen-free media. In the presence of dissolved oxygen, the lower temperature and chloride concentration limits were 122°F and 5 ppm chloride. There was no lower critical stress limit for SCC.

Hydrogen Sulfide Effects

A number of observations were made concerning sulfide stress cracking (SSC) at Wairakei. Medium and high-strength steels were susceptible to SSC in geothermal media up to at least 374°F. Mild steels and low strength alloys resisted SSC even under severe constant deformation tests. The highest safe yield strength was 88 ksi for carbon and low alloy steels and 110 to 120 ksi for high chromium alloys. Susceptibility to SSC was often related to hardness rather than yield strength (Hudgins et al. 1966). 13Cr turbine blading was resistant at a hardness below Brinell 180 and vulnerable above Brinell 190. SSC occurred in severely notched, low-

strength alloys exposed to cold, hydrogen sulfide-bearing condensate at yield strengths above 88 ksi. However, hydrogen sulfide-bearing dry steam was innocuous. SSC of highly susceptible steels did not occur in bore water at 464°F but did occur in the same water at 122°F.

Blistering was observed in some low strength alloys. Hydrogen infusion rates decreased to very low values after two to three weeks exposure above 212°F, probably because of corrosion films. Permeation rates were reduced by surface coatings such as Apexior No. 1 paint or by chemically-formed magnetite coatings.

4.10.3 Operating Experience

Overall plant experience (Marshall and Braithwaite 1973), erosion and thermal stress of production casings (Smith 1961), and well casing problems (Fooks 1964) have been documented for the Wairakei power plant. This information is summarized in the following sections.

4.10.3.1 Bore Casings and Wellhead Equipment

Conventional low strength (API grades J-55 and H-40) production casings have been used. J-55 has been adopted as the best compromise between strength and resistance to SSC. Internal corrosion has been minimal. Erosion by ejected sand has been controlled by slotted production liners.

External corrosion of surface casings has been severe near the surface where aerated ground water contacts the casings. Multiple casings with careful cementing of the annuli have controlled this problem.

Thermal stress has been severe. It has exceeded 60 ksi and may have caused mechanical failure of low strength casing alloys. High strength casings (API grade N-80 and above) have been avoided because of SSC. Medium-strength, sulfide-resistant French steel APS10M4 has shown promise in laboratory tests at Wairakei (Marshall and Tombs 1969). Thermal stress has been alleviated by careful cementing to avoid unsupported regions. Careful cementing also has prevented the formation of trapped water pockets which will collapse the casing after production is begun. Keeping bores flowing after initial "blow-in" has reduced thermal stress and prevented the formation of cold, nonaerated, hydrogen sulfide-bearing condensate, which is the main source of SSC.

Wellhead equipment of low-strength steels with stainless steel valve trim has performed satisfactorily. External protection (paint or cladding) against corrosion by airborne chloride sprays and steam has been required.

4.10.3.2 Internal Corrosion of Steam Transport Lines

The produced two-phase geothermal fluid is separated at the wellhead by steam separators. Carryover moisture averages about 0.05 percent, and the droplet chloride concentration is about 1500 ppm (McDowell 1976). The steam enters carbon steel pipelines at 50 to 130 psig. Velocity is 80 to 140 feet per second.

Extensive tests have shown that more than 99.8 percent of the chloride is scrubbed into condensate within 750 feet of the separator. Chloride concentrations in the condensate have been reported as high as 3.5 ppm (McDowell 1976).

The separated steam contains noncondensable gases, mostly carbon dioxide, as indicated previously in Table 4.10-2. It is thought that carbon dioxide is the major corrosion-controlling species in the steam. Temperature and velocity have lesser effects, while hydrogen sulfide seems to have little effect on uniform corrosion of the carbon steel (Conover 1979).

Braithwaite discussed chevron-shaped corrosion patches found inside two 30-in. steam lines in 1978 (Conover 1979). The lines were 0.50-inch thick carbon steel coated internally with magnetite, which is thought to be protective. It has been observed that chevron-shaped bare patches occur in the bottom 120 degrees of these pipelines. Penetrations (localized metal loss) of 100 to 250 mils have occurred. Until recently, the 15-year-old lines had been internally inspected annually, and no corrosion had been reported. In 1976, a biannual inspection routine was initiated, and at the first two-year inspection, the V-shaped corrosion patches were discovered.

After analyzing the metallic micro-structure, Braithwaite concluded that the magnetite buildup had been occurring for at least 10 years as a result of the annual shutdown and cool-off for inspection. Therefore, the scale and bare patches were probably not new but were discovered as a result of increased scrutiny in the biannual inspection. Much of the corrosion was thought to relate to the shutdown procedures previously used, which called for a gradual steam (and therefore temperature) reduction. This probably allowed much condensate to form and remain since the lines were cool. The new recommendation calls for a rapid steam shutdown so that the stored line heat will prevent any condensate pools and minimize localized corrosion (Conover 1979).

4.10.3.3 Turbines

The turbines at Wairakei are made of conventional turbine construction materials (cast steel casings, carbon steel rotors, 13Cr steel blades, shrouds, and lacings) heat-treated to a low-strength condition.

The shrouds and lacings are mechanically attached, rather than brazed, to avoid local hardening of the 13Cr steel. The rivets are annealed. Care is used to seal the joints in low pressure casing as thoroughly as possible to avoid air entry and accelerated corrosion by aerated media. Blade velocities are limited to 900 fps and moisture to 9 percent to avoid excessive blade corrosion (Marshall and Braithwaite 1973).

Oxygen concentrations as high as 100 ppm have been observed in low pressure turbines. The oxygen apparently leaks in around the stems of valves upstream from the turbine. No such problem has been observed in the high pressure intermediate pressure units. Studies have shown that expansion in valves carrying low pressure (less than 3 psig) steam can create a sufficient venturi effect to cause infiltration of air around the stems of butterfly valves. At higher pressures, any leakage around valve stems is outward, and no problem occurs (Conover 1979).

In 1978, Turbine No. 6 in Station A was disassembled for blade replacement. This was the first major repair in sixteen years of service. The sixth stage wheel was covered with a magnetite-type scale with bare corrosion patches attributed to corrosion by condensate.

The exhaust chambers have experienced similar localized corrosion in the past and have been fixed by welding stainless steel plating over the exposed surfaces (Conover 1979).

4.10.3.4 Separated Geothermal Water Pipes and Drains

At Wairakei, the separated (waste) geothermal fluid from the separators is discharged into open concrete drains. These drains have had to be continually cleared of silica scale by mechanical means and at considerable cost.

Many attempts have been made to control deposition: (1) addition of silica seed pellets to initiate deposition away from channel walls, (2) pH adjustment, and (3) addition of traces of various metallic ions. These efforts were either ineffective or uneconomical. Retaining the water in a stirred tank with a holdup time of one hour had little effect on deposition in the channels.

Dilution (1:1) of the geothermal discharge with cold water was tried. The silica deposition rate dropped by a factor of sixteen, and the resulting deposit was friable and more easily removed (Ellis and Mahon 1977).

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4.11 BACA (VALLES CALDERA) KGRA, NEW MEXICO

The Baca (or Valles Caldera) KGRA is located in the Valles Caldera, a Pleistocene caldera in north central New Mexico. Its location is shown in Figure 4.11-1. Geothermal wells are typically 5000 to 9000 ft deep. The reservoir consists of a small vapor-dominated cap above a liquid-dominated resource. The maximum recorded temperature is 625°F (Muffler 1979). A 50 MW power plant is planned for this site.

4.11.1 Fluid Chemistry

The resource at Baca is the neutral chloride type with about 7000 ppm total dissolved solids. Steam separated at 110 psig contains about 3 to 5 weight percent noncondensable gases, mostly carbon dioxide. Table 4.11-1 gives the observed range of composition of separated fluid from the Baca 11 well. Composition of the noncondensable gases in the separated steam is shown in Table 4.11-2. The phases, separated at 110 psig and 338°F, represent the range of chemistries observed during the corrosion tests discussed below.

4.11.2 Corrosion Tests

Corrosion data for Baca flashed fluids and steam are summarized in Tables 4.11-3 and 4.11-4. Limited test results were obtained in flashed wellhead fluid and steam; results are unavailable for unflashed wellhead fluid. Localized corrosion rates are available only for flashed steam.

4.11.2.1 Test Conditions

In two series of corrosion tests made at the Baca, New Mexico, geothermal site, geothermal fluid underwent flashing in the bore. The compositions of the two streams used in the corrosion tests are given in Tables 4.11-1 and 4.11-2.

In one test series, double-pipe heat exchanger materials were tested in (1) demisted steam, (2) steam with entrained fluid, and (3) flashed fluid. The steam and/or fluid flow was on the shell side, while cold, aerated water flowed on the tube side. Uniform corrosion rates were measured (Toney, Cohen, and Cron 1977).

In another test series, candidate turbine materials were exposed to demisted steam at 340°F and 11 psig. Coupons, U-bend specimens, and bent-beam specimens were exposed to the steam for 150 days. The steam was then shut off, and the specimens exposed to air-contaminated moisture for 10 days. This test procedure represented worst case conditions (Toney, Cohen, and Cron 1977).

02-6423-1

FIGURE 4.11-1. LOCATION OF BACA GEOTHERMAL RESOURCE

TABLE 4.11-1. COMPOSITION OF SEPARATED FLUID AT BACA, NM^a

COMPONENT	CONCENTRATION (ppm)	
Chloride (Cl ⁻)	3400	- 4400
Sulfate (SO ₄ ⁻²)	50	- 70
Bicarbonate (HCO ₃ ⁻¹)	57	- 128
Carbonate (CO ₃ ⁻²)	0	---
Hydrogen sulfide (H ₂ S)	1.5	- 6.0
Ammonia (NH ₃)	---	---
Silica (SiO ₂)	640	- 835
Calcium ion (Ca ⁺²)	27	- 46

^apH = 6.6 - 7.1

--- No data available

Source: Toney, Cohen, and Cron 1977

Testing of turbine materials also included corrosion fatigue tests. After exposure to demisted steam, specimens were subjected to cyclic stress, and the decrease in fatigue endurance limit (FEL) (defined in Section A.1.2.2) was determined.

4.11.2.2 Results and Discussion

Results of tests of heat exchanger materials are shown in Table 4.11-5. Of the eleven metals tested, only carbon steel showed significant uniform corrosion rates. Metallographic examination showed no evidence of intergranular corrosion. Localized corrosion data were not reported.

Results of tests on turbine materials exposed to demisted steam are given in Table 4.11-6. Twenty alloys were tested, and only carbon steel showed a uniform corrosion rate greater than 1.0 mpy. Pitting was a major problem; only A286 showed no pitting. The low hardness (Rc=23) AISI 616 also had good pitting resistance (pit rate was 2 mpy), but the same alloy at greater hardness (Rc=35) suffered an eight-fold increase in pitting rate.

TABLE 4.11-2. COMPOSITION OF STEAM FROM BACA, NEW MEXICO

COMPONENT	ppm (wt) IN STEAM ^a		% (MOL.) IN NONCONDENSABLE GAS ^b
Carbon dioxide (CO ₂)	33,700	- 47,390	98.15
Hydrogen sulfide (H ₂ S)	290	- 570	1.27
Ammonia (NH ₃)	1.5	- 6.0	0.01
Nitrogen (N ₂)	---		0.27
Hydrogen (H ₂)	---		0.21
Methane (CH ₄)	0	- 6	0.01
Ethane (C ₂ H ₆)	---		0.07
Propane (C ₃ H ₈)	---		0.01
Chloride (Cl ⁻) ^c	10		---

^aSource: Toney, Cohen, and Cron 1977

^bSource: Cosner and Apps 1978

^cEstimated from reported droplet carry-over

Because of test conditions, chloride stress corrosion cracking could not be distinguished from sulfide stress cracking and both forms of attack are reported as SCC. Most of the alloys tested were Rc=22 or higher (above acceptable limits for use in hydrogen sulfide-containing fluids) and failed the severe U-bend stress corrosion test. These materials did better at lower applied stress. Materials with lower strength/hardness levels may be good choices for use under higher applied stress conditions.

The macroscopic appearance of the bent beam specimens brazed with a low heat source showed evidence of a black corrosion product on the 50Ag-20Cu-28Zn-2Ni braze alloy.

The results of corrosion-fatigue tests are expressed as the ratio of FEL before exposure to FEL after exposure. The decrease in FEL would have been more severe if cyclic stress had been applied during exposure.

Fatigue fracture initiation generally occurred at corrosion pits. FEL ratios are plotted as a function of corrosion pit depth in Figure 4.11-2.

TABLE 4.11-3. CORROSION SCREENING RESULTS FOR BACA (VALLES CALDERA) FLASHED WELLHEAD FLUIDS

MATERIAL TESTED	NONAERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel	C ^a	-	-	-	-	-	-	-
AISI Type 316	A	-	-	-	-	-	-	-
Carpenter 20Cb3	A	-	-	-	-	-	-	-
Carpenter 7Mo	A	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	B	-	-	-	-	-	-	-
Inconel 600	A	-	-	-	-	-	-	-
Incoloy 825	A	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	A	-	-	-	-	-	-	-
<u>Copper Base</u>								
Admiralty Brass	B	-	-	-	-	-	-	-
70-30 Cupronickel	B	-	-	-	-	-	-	-
10 Al bronze	B	-	-	-	-	-	-	-

^a Other data indicate that a "B" rating is more probable.

KEY TO TABLE

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate ≥ 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- - Data not available

Source: Toney, Cohen, and Cron 1977

TABLE 4.11-4. CORROSION SCREENING RESULTS FOR BACA (VALLES CALDERA)
STEAM AFTER FLASHING

MATERIAL TESTED	DEMISTED STEAM			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
22 Ni ductile cast iron	A	-	-	-
Carbon steel (AISI 1060)	B	N	-	N
1.5Cr (AISI E52100)	-	X	-	N
2.25Cr-1Mo	A	-	-	-
1Cr-1.25Mo-0.25V	A	X	-	N
1.5Cr-3.5Ni-0.5Mo-0.1V	A	X	-	N
2.75Ni-0.5Mo-0.1V	A	X	-	N
AISI Type 316	A	-	-	-
Carpenter 20Cb3	A	-	-	-
Carpenter 7Mo	A	-	-	-
AISI Type 403 (12Cr)	A	X	-	X
AISI Type 616	A	X	-	X
12Cr-4Ni	-	X	-	X
M152	A	X	-	N
A286	A	N	-	N
<u>Nickel Base</u>				
Monel 400	-	-	-	-
Inconel 600	A	-	-	-
Inconel X-750	A	X	-	X
Incoloy 825	A	-	-	-
<u>Titanium Base</u>				
Titanium	A	-	-	-
Ti-5Al-2.5Sn	A	-	-	-
<u>Copper Base</u>				
Admiralty Brass	B	-	-	-
22Ni-6Pb Brass	A	-	-	-
10 Al bronze	B	-	-	-
70-30 Cupronickel	B	-	-	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1 mpy
- B - uniform corrosion rate > 1 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate > 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- - Data not available

Source: Toney, Cohen, and Cron 1977

TABLE 4.11-5. RESULTS OF CORROSION TESTS OF HEAT EXCHANGER
MATERIALS AT BACA, NEW MEXICO KGRA

MATERIAL TESTED	CORROSION RATE IN STEAM (mpy)	CORROSION RATE IN STEAM WITH EN-TRAINED FLUID (mpy)	CORROSION RATE IN FLASHED FLUID (mpy)
<u>Iron Base</u>			
Carbon Steel ^b	31	18	32
AISI Type 316	0	0	0
Carpenter 20Cb3	0	0	0
Carpenter 7Mo	0	0	0
<u>Nickel Base</u>			
Monel 400	2	2	3
Inconel 600	0	0	0
Incoloy 825	0	0	0
<u>Titanium Base</u>			
Titanium	0	0	0
<u>Copper Base</u>			
Admiralty Brass	3	2	1
70-30 Cupronickel	5	5	3
10 Al Bronze	6	6	4

^a Tests were at 340°F for 69 days. Samples were tubes in a simulated heat exchanger with shell side exposed to geothermal media and tube side exposed to cold, aerated water. Pitting, crevice corrosion, and stress corrosion cracking (SCC) data were not reported. Metallographic examination showed no indication of intergranular corrosion.

^b Most corrosion was on the tube side of the specimen (exposed to cold aerated water).

Source: Toney, Cohen, and Cron 1977

TABLE 4.11-6. CORROSION TEST RESULTS FOR TURBINE MATERIALS IN FLASHED STEAM AT BACA (VALLES CALDERA)

ALLOY TESTED	MATERIAL PROPERTIES		RESULTS OF CORROSION TESTS ^a				
	Standards Designation	Hardness Rockwell-A ^b	Uniform Corrosion ^c (mpy)	Pitting ^d (mpy)	U-bend ^e	SCC	
						Bent-Beam ^f	Fracture ^f Mode
Carbon Steel	AISI 1060	69.0	1.3	general	ND	ND	-
1.5Cr	AISI E52100	70.0	-	13.7	-	MF	T
2.25Cr-1Mo Steel	ASTM-A541 C1 6	57.3	0.7	-	-	-	-
1Cr-1.25Mo-.25V	ASTM-A470 C1 8	60.2	0.6	6.8	MF	MF(76) ^g	T, I
1.5Cr-3.5Ni-.5Mo-.1V Steel	ASTM-A470 C1 5	60.2	0.4	9.1	MF	MF(72) ^g	T
2.75Ni-.5Mo-.1V Steel	ASTM-A470 C1 4	59.5	0.7	9.1	MF	MF(80) ^g	T
22Ni Ductile Cast Iron		-	0.7	-	-	-	-
12Cr Steel	Type 403	61.1	0.2	29.7	F	ND(70-100) ^g	T, I
12Cr Steel ^h	Type 403	73.0	-	13.7	-	ND	-
12Cr Steel ⁱ	Type 403	-	-	-	-	ND	-
12Cr Steel ^j	Type 403	-	-	-	-	MF	T
12Cr-1Mo-.25V Steel ^k	Type 616	61.9	0.1	2	ND	ND(70-100) ^g	-
12Cr-1Mo-1W-.25V Steel ^l	Type 616	68.1	0.2	16.0	F	ND(50-70) ^g	T
12Cr-4Ni Steel		67.7	-	13.7	F	MF	I, T
M152 Steel		70.0	0.1	16.0	ND	ND(40-60) ^g	-
A286 Steel		67.2	.04	Nil	ND	ND	-
Monel		43.1	-	scale ^m	-	-	-
Inconel X - 750		69.3	.04	2	F	MD	I
22Ni-6Pb-Brass			.6 ⁿ	-	-	-	-
Ti-5Al-2.5Sn		67.5	.04	-	-	-	-

^aSpecimens exposed to separated demisted steam at 340°F and 110 psig for 150 days and to air/moisture for final 10 days of 160 day period.

^bR_A 61.5 = R_C 22

^cCalculated from weight loss data.

^dCalculated from maximum pit depth

^eStress cracking of U-bends and bent-beams key:

ND - no fissures or cracks detected

MF - microscopic fissures $\leq$ grain depth

F - macroscopic fissures or fracture

^fT - transgranular mode

I - intergranular mode

^gPercent of yield stress applied

Source: Toney, Cohen, and Cron 1977

^hOne half of specimen flame hardened to R_A 73.0

ⁱBrazed at <1450°F using 50Ag-20Cu-28Zn-2Ni braze alloy to attach cobalt-based erosion shield (65Co-30Cr-4.5W-1.25C)

^jBrazed at high temperature using same braze and shield alloys

^kLow hardness

^lHigh hardness

^mCovered with flaky nonadherent black scale

ⁿThis is a minimum corrosion rate. Coupon covered with very adherent black scale which could not be completely removed

FIGURE 4.11-2. RATIOS OF FEL-AFTER-EXPOSURE TO FEL-BEFORE-EXPOSURE AS A FUNCTION OF CORROSION PIT DEPTH

Source: Toney, Cohen, and Cron 1977

All alloys exhibited significant reductions in FEL with the occurrence of pitting. FEL reductions of 16 to 28 percent were caused by pitting during the first 34 days of exposure. The most commonly used 12Cr (AISI 403) bucket alloy exhibited the smallest reduction. The 98-day exposure resulted in a relatively insignificant change in the FEL values. Compared to the 34-day exposure, a marked increase in pit depth occurred during the 98-to-160-day exposure period.

At the end of the final exposure, FEL values were reduced 36 to 52 percent. With pitting to a depth of approximately 9 to 10 mils, the FEL ratios of AISI 616 heat-treated to "low" and "high" hardness levels were lowered approximately 50 percent. The two low tensile strength alloys, AISI 403 ($R_A 61$) and AISI 616 ($R_A 62$), did not exhibit the same reductions in FEL for comparable corrosion pit depths. This suggests that at comparable hardness levels, the AISI 403 is less notch sensitive in fatigue than the AISI 616.

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4.12 BRADY HOT SPRINGS, NEVADA

The Brady Hot Springs KGRA is a liquid-dominated resource located in Churchill and Lyons Counties, Nevada (see Figure 4.12-1). Numerous wells have been drilled to depths from 250 to over 6900 feet. Down-hole temperatures average 338°F but may reach as high as 415°F (Muffler 1979). The highest reported wellhead temperature is 325°F.

The Brady Hot Springs KGRA is used as a source of process heat for a food dehydration plant. The geothermal water used is supplied by Brady Well No. 8 or other wells at 250°F with a flow rate of 712 gpm (Thiel 1980). A pressure of 150 psig is maintained throughout the system to prevent flashing. This eliminates calcium carbonate buildup and minimizes valve maintenance. Geothermal heat is transferred to the drying air by circulating the pumped fluid through ten steel coils. Space heating is provided by passing the spent water from the process coils through a bank of coils located high on one wall of the building.

Another well near the plant, Dommer No. 1, is also used for plant and process water. Dommer No. 1 produces water at about 210°F. The water is passed through two air-cooled cooling towers to reduce the temperature to a level suitable for washing dirt and foreign matter from vegetables during the first stage of the dehydration process. Other wells near the plant are used as backups in the event the main well is forced offline. Thus production loss due to well shutdown is minimal (Thiel 1980).

4.12.1 Fluid Chemistry

The Brady resource is a neutral chloride water containing about 2330 ppm total dissolved solids. Table 4.12-1 presents the compositions of self-pumped and pumped separated waters. Although surface discharges (fumeroles) contain hydrogen sulfide (approximately 3 ppm), no hydrogen sulfide has been detected in the fluid from the producing wells (Ellis 1979). No data are available concerning other noncondensable gases.

4.12.2 Material Tests

Limited corrosion test results are available from the Brady Hot Springs KGRA. These results are summarized in Materials Screening Table 4.12-2.

4.12.2.1 Methods

Tests were performed to aid the selection of materials for binary heat exchangers. In one test, weight loss coupons of each alloy were exposed to separated geothermal water at an average temperature of 318°F (range 286° to 320°F). The actual chemistry of the water was not reported,

FIGURE 4.12-1. LOCATION OF BRADY HOT SPRINGS GEOTHERMAL RESOURCE

TABLE 4.12-1. TYPICAL COMPOSITION OF GEOTHERMAL FLUID FROM THE
BRADY HOT SPRINGS KGRA

COMPONENT		SEPARATED FLUID ^a		PUMPED UNFLASHED FLUID ^b
<u>Key Species:</u>		pH	6.9 - 7.05	-
		ppm		ppm
Chloride	(Cl ⁻)	820	- 1400	942
Sulfate	(SO ₄ ⁻²)	270	- 400	320
Bicarbonate	(HCO ₃ ⁻)	100	- 102	7.3
Carbonate	(CO ₃ ⁻²)	-		34
Carbon Dioxide	(CO ₂)	-		6
Hydrogen sulfide	(H ₂ S)	-	ND ^c	3
Ammonia	(NH ₃)	-		0.02
<u>Other Species:</u>				
Silica	(SiO ₂)	150		180
Sodium	(Na)	100	- 620	775
Calcium	(Ca)	52	- 70	31
Potassium	(K)	38	- 40	6
Magnesium	(Mg)	0.4	- 1.5	-
Boron	(B)	5.5	- 5.6	0.3

- : Data not available

^aSource: USGS Geotherm B 1979

^bSource: Cieslewicz 1979

^cNone detected

Source: Ellis 1979

TABLE 4.12-2. BRADY HOT SPRINGS CORROSION SCREENING RESULTS FOR WELLHEAD FLUID

MATERIAL TESTED	NONAERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Stainless Steel</u>								
AISI T304	A	N	-	-	-	-	-	-
AISI T316	A	N	-	-	-	-	-	-
<u>Copper-Based Alloys</u>								
CA 443	A	N	-	-	-	-	-	-
CA 613	B	X	-	-	-	-	-	-
CA 630	A	X	-	-	-	-	-	-
CA 715	B	N	-	-	-	-	-	-
CA 903	B	N	-	-	-	-	-	-
CA 952	B	N	-	-	-	-	-	-
CA 958	A	X	-	-	-	-	-	-
<u>Nickel-Based Alloys</u>								
Monel 400	B	N	-	-	-	-	-	-
Hastelloy B	A	N	-	-	-	-	-	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1 mpy
 B - uniform corrosion rate > 1 mpy but ≤ 10 mpy
 C - uniform corrosion rate > 10 mpy but ≤ 50 mpy
 D - uniform corrosion rate > 50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 - - data not available

Source: Cieslewicz 1979

but it was reported that the fluid was nonaerated and that fluid velocity was 5 to 14 feet per second. Test duration was 39 days.

In the second test, weight loss coupons were exposed to pumped geothermal water in a discharge line. Temperature was 302°F, and pressure was 140 psig. Velocity was not reported. The fluid was nonaerated. Fluid composition is given in column three of Table 4.12-1. Coupons for both tests were supplied and evaluated by Ampco Metal, Division of Ampco-Pittsburgh Corporation (Cieslewicz 1979). No testing for crevice corrosion or stress corrosion cracking was performed.

4.12.2.2 Results and Discussion

The results of these two tests are presented in Tables 4.12-3 and 4.12-4. The following discussion is based on the results presented in these tables.

Upon removal from the test environment, all coupons were reported to be covered with an adherent black scale of unspecified composition. This scale was difficult to remove. Treatment with 1:1 hydrochloric acid produced a strong odor of hydrogen sulfide (Cieslewicz 1979). All of the alloys showed uniform corrosion rates (determined by weight loss) of less than 5 mpy in both test environments. Uniform corrosion rates of the copper-based alloys were two- to fourfold higher in the pumped fluid. More detailed results are discussed in the following paragraphs.

Stainless Steels

The uniform corrosion rate of both AISI 304 and AISI 316 was less than 0.2 mpy in the first test. Only AISI 304 was exposed in the second test; its uniform corrosion rate was not affected. Incipient pitting of the AISI 304 occurred in pumped fluid. There was no change in the surface finish of either alloy in unpumped fluid (Cieslewicz 1979).

Copper-Based Alloys

CA 443 (Arsenical Admiralty Brass) was exposed only in the unpumped fluid. It corroded at 0.6 mpy, and there was no reported change in surface finish. CA 613 (7Al-3.5Fe bronze) had a uniform corrosion rate of approximately 2.5 mpy in unpumped fluid, where pitting also occurred. The depth of attack was not reported, but it was stated that low (approximately 10X) magnification was required to detect the pits. In pumped fluid, the uniform corrosion rate of CA 613 increased two- to threefold. The surface was etched, but no pits were reported. Welding appeared to have little effect on the weight loss.

The uniform corrosion rate of CA 630 (9Al-5Ni-3Fe bronze) was about equal to the rate of CA 443 in unpumped fluid. Pits detectable at

TABLE 4.12-3. CORROSION RESULTS IN SEPARATED WATER AT BRADY HOT SPRINGS,
NEVADA

MATERIAL TESTED	NON-AERATED FLUID ^a			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Stainless Steels</u>				
T 304	0.15	N	-	-
T 316	0.07	N	-	-
<u>Copper-Based Alloys</u>				
CA 443	0.62 ^b	N	-	-
CA 613	2.5 ^b	X ^c	-	-
CA 630	0.67 ^b	X ^c	-	-
CA 715	4.8 ^b	N	-	-
CA 903	3.1 ^b	N	-	-
CA 952	2.4 ^b	X ^c	-	-
CA 958	0.61 ^b	X ^c	-	-
<u>Nickel-Based Alloys</u>				
Monel 400	3.0	N	-	-
Hastelloy B	0.59	N	-	-

^a Coupons exposed to air-free separated water at 318°F for 39 days

^b Covered with black tenacious scale

^c Pits visible at low (approximately 10X) magnification

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - No data available

Source: Cieslewicz 1979

TABLE 4.12-4. CORROSION RESULTS IN PUMPED GEOTHERMAL FLUID AT BRADY, NEVADA

MATERIAL TESTED	NON-AERATED FLUID ^a			
	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC
<u>Stainless Steel</u>				
T 304	0.05-0.12	X ^b	-	-
<u>Copper-Based Alloys</u>				
CA 613	4.8-8.6	N	-	-
CA 613 (welded)	3.7-6.4	N	-	-
CA 958	2.0	X ^c	-	-

^aCoupons exposed for 40 days at 302°F.

^bIncipient pitting

^cPits visible at low (approximately 10X) magnification

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - No data available

Source: Cieslewicz 1979

approximately 10X magnification were reported. No depth of attack was given. The alloy was not tested in pumped fluid. CA 715 (70-30 cupro-nickel) corroded at 3.7 to 4.8 mpy in unpumped fluid. It was etched. The alloy was not tested in the pumped fluid.

CA 903 (cast tin bronze) corroded at 3.1 mpy or less in unpumped fluid. Etching occurred, but no pits were reported. It was not tested in pumped fluid. CA 952 (9Al-3Fe bronze) corroded at about two-thirds of the rate of CA 903 in unpumped fluid. It was less severely etched, but the difference was not quantified. It was not tested in the pumped fluid. CA 958 (9Al-5Ni-4Fe bronze) was exposed to both pumped and unpumped fluids. In the unpumped fluid the uniform corrosion rate was about 0.6 mpy. A fourfold increase in uniform corrosion was observed after exposure to pumped fluid. Pits detectable at low (approximately 10X) magnification occurred in both environments. Depths of attack were not reported.

Nickel-Based Alloys

Monel 400 corroded at 3 mpy or less in unpumped fluid. The surface finish was etched. The material was not exposed to pumped fluid. Hastelloy B was comparable to CA630 in both uniform corrosion rate (approximately 0.6 mpy) and pitting resistance when exposed to unpumped fluid. It was not tested in pumped fluid.

4.12.3 Operating Experience

The temperature of each dryer coil at the food dehydration plant is controlled by a pneumatic ball valve. Each coil also has a vent valve and an automatic drain valve for emergency purposes. Ball valves are used throughout the system instead of gate or globe valves. This provides ease of maintenance and longer valve life (Thiel 1980).

In June 1979, Brady Well No. 5 was stimulated after cleaning to remove a calcium carbonate plug. A blowout occurred due to failure of the production casing. The interior of the casing showed no signs of corrosion. The exterior, however, was extensively corroded below ground level. The attack became more severe with increasing depth. At the point of failure, the wall was less than 0.125 inch thick with some perforations more than one inch in diameter. Further investigation revealed no sign of the surface conductor, the upper string casing, or their associated cements (Ellis 1979).

The well is located in a mineral flat. It was determined that failure was caused by corrosion due to aerated chloride- and/or sulfate-rich groundwater. This groundwater destroyed the surface conductor, upper-string casing and associated cements. Blowout occurred when the weakened production casing could not withstand the mechanical production stresses (Ellis 1979).

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4.13 CASA DIABLO, CALIFORNIA

The Casa Diablo KGRA, also called the Mono-Long KGRA, is located in Long County, California (see Figure 4.13-1). Wells 500 to 1100 feet deep produce water at temperatures of 270° to 360°F at the wellhead. The higher temperature wells produce fluids containing about 18 percent steam at 40 psig (Cosner and Apps 1978). The California Energy Commission has demonstrated a direct utilization, space heating system at Casa Diablo.

4.13.1 Fluid Chemistry

Only scanty fluid chemistry data are available from this KGRA. The fluid is a neutral chloride water of less than 1000 ppm total dissolved solids. For unflashed fluid the pH is approximately 6.5. Flashing raises the pH about two units. Table 4.13-1 gives the composition of unflashed fluid from one well at Casa Diablo. This chemistry is representative of the resource.

The separated steam at Casa Diablo contains 0.87 percent (weight) noncondensable gas. The gas is reported to be composed of carbon dioxide with trace hydrogen sulfide (Cosner and Apps 1978). Composition is given in Table 4.13-2.

4.13.2 Corrosion Test

A test of eleven candidate materials for heat exchangers was performed by Magma Energy Company and Ampco Metals Division, Ampco-Pittsburgh Corporation. Results are summarized in Screening Table 4.13-3.

4.13.2.1 Methods

Weight loss coupons of eleven alloys were mounted on a spool rack and exposed to flowing geothermal water for 73 days. The average temperature was 331°F (range from 327°F to 345°F). The velocity was 5 to 14 feet per second. The chemistry of the fluid during the test is not available. The fluid reportedly was air-free (Cieslewicz 1979). After the test, the coupons were evaluated by Ampco Metals Division. Uniform corrosion rate was calculated from weight loss. Changes in surface finish were reported. No testing of crevice corrosion or stress corrosion cracking was performed.

4.13.2.2 Results and Discussion

Results are tabulated in Table 4.13-4 and discussed in more detail below. All information was obtained through personal communication with John Cieslewicz (Cieslewicz 1979).

Both AISI 304 and AISI 316 had uniform corrosion rates less than 0.05 mpy. There was no observed change in surface finish for either alloy.

FIGURE 4.13-1. LOCATION OF CASA DIABLO GEOTHERMAL RESOURCE

TABLE 4.13-1. COMPOSITION OF UNFLASHED FLUID FROM CASA DIABLO^a

COMPONENT		CONCENTRATION (ppm)
<u>Key Species:</u>		
Chloride	(Cl ⁻)	227
Sulfate	(SO ₄ ⁻²)	96
Carbon Dioxide	(CO ₂)	180
Hydrogen Sulfide	(H ₂ S)	14
Ammonia	(NH ₃)	0.1
<u>Other Species:</u>		
Silica	(SiO ₂)	200
Calcium ion	(Ca ⁺²)	4
Sodium ion	(Na ⁺)	308
Potassium ion	(K ⁺)	32
Lithium ion	(Li ⁺)	0.3
Boron	(B)	11
Fluoride	(F ⁻)	20
Arsenic	(As)	0.2

^apH = 6.5

Source: Cosner and Apps 1978

Nickel-Based Alloys

Monel 400 had a uniform corrosion rate of 4.2 to 5.7 mpy, and the surface finish was etched. When removed from the test environment, the coupon was covered with a thick, adherent black scale. The corrosion rate of Hastelloy B was not given. An increase in weight was reported. The coupon was covered with an irregular black scale. The scale was thick and tenacious. Pits requiring low (approximately 10X) magnification for detection are reported. The depth of attack was not reported.

TABLE 4.13-2. COMPOSITION OF SEPARATED STEAM AT CASA DIABLO

NONCONDENSABLE COMPONENT	% WT.	% VOL.	MOLE FRACTION OF GAS
Carbon dioxide (CO ₂)	0.858	0.353	0.983
Hydrogen Sulfide (H ₂ S)	0.0118	0.00627	0.017
Total	0.87	0.359	1.000

Source: Cosner and Apps 1978

Copper-Based Alloys

The tested copper alloys were covered with a thick black scale which was difficult to remove. The scale was not analyzed, but it may have been largely copper sulfide. Even if corrosion rates were suitably low, the rapid formation of this scale, probably a corrosion product, suggested that these alloys would not be satisfactory for heat exchange surfaces.

The corrosion rate of CA 443 (Arsenical Admiralty Brass) was less than 0.2 mpy, and there was no observed change in surface finish. The corrosion rates of CA 630, CA 952, and CA 958 were all similar. The range was 2 to 5 mpy. All of these alloys are nine percent Al bronzes containing two to four percent Fe. CA 630 and CA 958 contain five percent Ni. The surfaces of these alloys were etched, but no pits were visible at low (approximately 10X) magnification. CA 952 does not include nickel. The surface of this alloy was also etched, and pits were visible at low (approximately 10X) magnification. Depth of attack was not reported.

CA 613 is a 7Al-3.5(max)Fe bronze containing no nickel. Uniform corrosion was more severe than for the other aluminum bronzes. The rate was 8 to 10 mpy. The surface was etched, but no pits were reported. CA 715 (70-30 cupronickel) had a corrosion rate comparable to the 9 percent Al bronzes (approximately 3.5 mpy). It was etched, but no pits were reported. Cast tin bronze (CA 903) was the least corrosion-resistant alloy tested. The uniform corrosion rate was 32 mpy. Etching was heavy (grain boundaries clearly visible). No pits were reported.

TABLE 4.13-3. MATERIAL SCREENING RESULTS IN FLUID IN CASO DIABLO

MATERIAL TESTED	NONAERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Stainless Steels</u>								
AISI T304	A	N	-	-	-	-	-	-
AISI T316	A	N	-	-	-	-	-	-
<u>Nickel-Based Alloys</u>								
Monel 400	B	N	-	-	-	-	-	-
Hastelloy B	*	X	-	-	-	-	-	-
<u>Copper-Based Alloys</u>								
CA443	A	N	-	-	-	-	-	-
CA613	C	N	-	-	-	-	-	-
CA630	B	N	-	-	-	-	-	-
CA715	B	N	-	-	-	-	-	-
CA903	C	N	-	-	-	-	-	-
CA952	B	X	-	-	-	-	-	-
CA958	B	N	-	-	-	-	-	-

Key to Table

- A - general corrosion rate <1 mpy
 B - general corrosion rate ≥ 1 mpy but ≤ 10 mpy
 C - general corrosion rate >10 mpy but ≤ 50 mpy
 D - general corrosion rate >50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 * - weight gain reported
 - - no data available

Source: Cieslewicz 1979

TABLE 4.13-4. CORROSION TEST RESULTS FOR CASA DIABLO KGRA, CALIFORNIA

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion (mpy) ^a	Pitting	Crevice Corrosion	SCC
<u>Stainless Steels</u>				
AISI 304	0.04	N	-	-
AISI 316	≤0.05	N	-	-
<u>Copper Alloys</u>				
CA 443	0.20	N	-	-
CA 613	9.3	N	-	-
CA 630	≤2.2	N	-	-
CA 715	3.5	N	-	-
CA 903	31.7	N	-	-
CA 952	3.5	X ^b	-	-
CA 958	3.9	N	-	-
<u>Nickel Alloys</u>				
Monel 400	5.0	N	-	-
Hastelloy B	+ ^c	X ^b	-	-

^a Average of two coupons exposed 73 days at 331°F

^b Visible at 10X magnification. Depth not reported.

^c Weight gain.

KEY TO TABLE

N - Not detected

X - Detected

- - No data available

Source: Cieslewicz 1979

4.13.3 Operating Experience

No operating experience is available.

REFERENCES

Cieslewicz, J.M., 1979. Personal communication. Corrosion metallurgist. Ampco Metal Corporation.

Cosner, S.R., and Apps, J.A., May 1978. A compilation of data on fluids from geothermal resources in the United States. DOE Contract No. W-7405-ENG-48. LBL-5936 (UE-66b) (TID-4500-R66) Berkeley, CA: Earth Sciences Division, Lawrence Berkeley Laboratory, University of California.

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4.14 EAST MESA KGRA, CALIFORNIA

The East Mesa KGRA is located in the Imperial Valley of southern California. Figure 4.14-1 shows the location of the KGRA. At least twenty wells have been drilled at East Mesa. Well depths vary from 2950 ft to 9200 ft. The maximum reported temperature is 399°F at 7550 ft.

A 10 MW direct binary cycle plant designed for a working temperature of 356°F has been constructed, and a double flash steam plant of 48 MWe capacity is planned (Muffler 1978).

Three desalting systems have been installed and operated at East Mesa. Tests have been conducted on two distillation systems: the first is a multistage flash system, and the second is a vertical tube evaporator. Both have taken geothermal brine and produced a high quality product water. The third installation is a high temperature electrodialysis plant, which produces a stream that requires further treatment.

As originally designed, the multistage flash evaporator had three flash stages. Each stage vented through a pressure control valve into a common condenser. Fifteen percent product recovery was possible. In an effort to increase recovery, three heat exchangers were added to the system to recover heat from the flashing brine. Steam from the site wellhead separator was directed to the first heat exchanger; vapor from the first and second flash stages was sent to the other two heat exchangers. The resulting flow scheme could be compared to a seawater multistage flash plant with heat input, heat recovery, and heat rejection sections.

The vertical tube evaporator originally consisted of a triple-effect unit and a single-effect unit, each receiving geothermal brine and steam separately and venting to the atmosphere. To improve heat transfer and operational stability, several modifications were subsequently made. The first two effects of the triple-effect unit were converted from upflow to downflow operation (the third remained in upflow mode). Brine and product pumps were added to all effects. The single-effect unit was converted to a condenser to handle third effect vapor, and a vacuum pump was added for noncondensable gas removal.

The third system that was installed was a high temperature electrodialysis unit. The unit consisted of equipment for coagulation with lime and magnesium oxide, sedimentation, filtration, and temperature adjustment. Teflon®-backed membranes, as well as Dacron®- and polypropylene-backed membranes in thincell configurations, were tested in a single-stage stack (Boegli, Suemoto, and Trompeter 1977).

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FIGURE 4.14-1. LOCATION OF EAST MESA GEOTHERMAL RESOURCE

4.14.1 Fluid Chemistry

The East Mesa resource is a neutral chloride water with 1000 to 26,000 ppm total dissolved solids (TDS). The first well drilled was Mesa 6-1, and it produced water with about 26,000 ppm TDS. All subsequent wells have yielded waters containing much lower TDS. Table 4.14-1 presents typical chemistry from four wells at East Mesa. These analyses are for unflushed brine. No information on free carbon dioxide concentration is known, but it has been estimated that in the reservoir, the concentration may be about 2000 ppm (Suemoto 1977). The total flow at the surface contains 0.2 percent (weight) noncondensable gas of which carbon dioxide is 90 percent. The composition of the remaining gas is not known, but it does contain hydrogen sulfide (U. S. Bureau of Reclamation (USBR) 1977). Flashing of the fluid evolves carbon dioxide and raises the pH about three units (from pH 5.5 to pH 8.9) (USBR 1977). The loss of carbon dioxide and rise in pH can be expected to cause many problems with calcium carbonate scaling.

4.14.2 Corrosion Tests

A short-term materials test has been performed on-site at East Mesa (Needham, 1976; Needham et al. 1977), and a test in simulated Mesa 6-1 fluid has been reported (Carter and Cramer 1974). The results of these two tests are summarized in Material Screening Tables 4.14-2 through 4.14-6. A third test measured the effect of acidification and reduction in temperature. The first two tests are discussed together in sections 4.14.2.1 and 4.14.2.2, and the acidification results are discussed in Section 4.14.2.3.

4.14.2.1 Laboratory Tests

Prior to field testing, preliminary laboratory tests were conducted in East Mesa wellhead fluid. These tests were screening tests to determine corrosion resistance of commercially available metals and alloys in aerated and deaerated brines.

Methods and Conditions

Twenty-five alloys were tested for uniform corrosion, pitting, crevice corrosion, and stress corrosion cracking (Carter and Cramer 1974; Hall 1975). Carbon steel was used as a control. General corrosion and pitting samples were coupons. Crevice samples were made by overlapping two strips of the alloy and fastening with Teflon® bands. Stress samples were bent around a pipe and retained under stress with Teflon® clips.

The laboratory test solution was obtained from a sample of wellhead fluid from Mesa 6-1 well. The composition of this solution is given in Table 4.14-7.

TABLE 4.14-1. COMPOSITION OF UNFLASHED FLUID FROM FOUR EAST MESA KGRA WELLS

COMPONENT	WELL			
	Mesa 6-1	Mesa 6-2	Mesa 8-1	Mesa 31-1
<u>Key Species:</u> pH	5.45	6.21	6.27	6.27
	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>
Chloride (Cl ⁻)	16850	2142	500	510
Sulfate (SO ₄ ⁻²)	42.8	156	173	183
Bicarbonate (HCO ₃ ⁻)	202	560	417	845
Carbonate (CO ₃ ⁻²) ^a	0	0	0	0
Hydrogen sulfide (H ₂ S)	3.0	1.5	1.0	0.3
Ammonia (NH ₃)	40.8	14.7	4.95	2.5
<u>Other Species:</u>				
Total Dissolved Solids (TDS)	26300	5000	1600	2900
Silica (SiO ₂)	320	269	389	274
Calcium ion (Ca ⁺²)	1360	16.4	8.5	8.9
Barium (Ba)	14	0.25	0.15	0.15
Sodium (Na)	8100	1700	610	730
Arsenic (As)	0.26	0.22	0.05	0.025
Boron (B)	9.75	7.45	1.6	2.5
Potassium (K)	1050	150	70	85
Fluorine (F)	0.99	1.23	1.6	1.42

^aNo value for free carbon dioxide is available

Source: Suemoto 1977

TABLE 4.14-2. EAST MESA CORROSION SCREENING RESULTS FOR WELLHEAD FLUID^a

MATERIAL TESTED	NONAERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
Iron Base								
Carbon Steel (AISI 1020)	B(C)	(N)	-	(N)	(C)	(N)	-	(N)
AISI 4130	B(A)	(N)	(N)	(N)	(C)	(N)	(N)	(N)
AISI Type 302	(A)	(N)	(N)	(N)	(A)	(N)	(X)	(N)
AISI Type 316L	A(A)	(N)	(X)	(N)	(A)	(N)	(X)	(N)
AISI Type 430	A	X	-	-	-	-	-	-
Sandvik 3RE60	(A)	(N)	(X)	(N)	(A)	(N)	(X)	(N)
E-Brite 26-1	A(A)	X(N)	(N)	(N)	(A)	(N)	(N)	(N)
Carpenter 20	(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Nickel Base								
Monel 400	(A)	(N)	(N)	(N)	(B)	(N)	(N)	(N)
Inconel X-750	(A)	(N)	-	(N)	(A)	(N)	-	(N)
Inconel 625	A(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Hastelloy S	A(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Hastelloy G	(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Hastelloy C-276	A(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Titanium Base								
Titanium	(A)	(N)	(N)	(N)	(A)	(N)	(X)	(N)
Ti-1.7W	(A)	(N)	(N)	(N)	(A)	(N)	(N)	(N)
Ti-1.5Ni	A(A)	(N)	-	(N)	(A)	(N)	-	(N)
Ti-10V	(A)	(N)	-	(N)	(A)	(N)	-	(N)
Aluminum Base								
2024-T3	(B)	(N)	-	(N)	(C)	X	-	(N)
6061-T6	(B)	(N)	-	*	(B)	(N)	-	*
5005	(D)	X	X	-	-	-	-	-
Copper Base								
Copper	(B)	(N)	-	(N)	(D)	(N)	-	(N)
Cu-2Fe	(B)	(N)	-	(N)	(C)	(N)	-	(N)
90-10 Brass	(B)	(N)	(N)	(N)	(B)	(N)	X	(N)
70-30 Brass	(B)	(N)	(N)	(N)	(B)	(N)	X	(N)
90-10 Cupronickel	(A)	(N)	(N)	(N)	(B)	(N)	(N)	(N)
70-30 Cupronickel	(B)	(N)	-	(N)	(C)	(N)	-	(N)
Molybdenum Base								
TZM	(A)	(N)	-	(N)	(B)	(N)	-	(N)

KEY TO TABLE

- A - uniform corrosion rate <1 mpy
 B - uniform corrosion rate >1 mpy but <10 mpy
 C - uniform corrosion rate >10 mpy but <50 mpy
 D - uniform corrosion rate >50 mpy
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 * - increased uniform corrosion
 - - no data available

^aData in parentheses are laboratory results

Source: Carter and Cramer 1974; Needham 1976; Needham et al. 1977

TABLE 4.14-3. EAST MESA CORROSION SCREENING RESULTS FOR LIQUID
STREAM AFTER FIRST FLASH

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel (AISI 1020)	B	N	X	-
AISI 4130	B	N	X	-
AISI Type 302	-	-	-	-
AISI Type 316L	A	X	-	-
AISI Type 430	A	X	-	-
Sandvik 3RE60	-	-	-	-
E-Brite 26-1	-	-	-	-
Carpenter 20	A	X	-	-
<u>Nickel Base</u>				
Monel 400	-	-	-	-
Inconel X-750	-	-	-	-
Inconel 625	A	-	-	-
Hastelloy S	A	R	-	-
Hastelloy G	-	-	-	-
Hastelloy C-276	A	-	-	-
<u>Titanium Base</u>				
Titanium	-	-	-	-
Ti-1.7W	-	-	-	-
Ti-1.5Ni	A	R	-	-
Ti-10V	-	-	-	-
<u>Aluminum Base</u>				
2024-T3	-	-	-	-
6061-T6	-	-	-	-
5005	C	X	-	-
<u>Copper Base</u>				
Copper	-	-	-	-
Cu-2Fe	-	-	-	-
90-10 Brass	-	-	-	-
70-30 Brass	-	-	-	-
90-10 Cupronickel	-	-	-	-
70-30 Cupronickel	-	-	-	-
<u>Molybdenum Base</u>				
TZM	-	-	-	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate > 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- R - general roughening of surface
- - no data available

Source: Carter and Cramer 1974; Needham 1976; Needham et al. 1977

TABLE 4.14-4. EAST MESA CORROSION SCREENING RESULTS FOR LIQUID
STREAM AFTER SECOND FLASH

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel	B	N	X	-
AISI 4130	B	N	X	-
AISI Type 302	-	-	-	-
AISI Type 316L	A	X	-	-
AISI Type 430	A	X	-	-
Sandvik 3RE60	-	-	-	-
E-Brite 26-1	A	N	-	-
Carpenter 20	-	-	-	-
<u>Nickel Base</u>				
Monel 400	-	-	-	-
Inconel X-750	-	-	-	-
Inconel 625	A	-	-	-
Hastelloy S	A	-	-	-
Hastelloy G	-	-	-	-
Hastelloy C-276	A	N	N	-
<u>Titanium Base</u>				
Titanium	-	-	-	-
Ti-1.7W	-	-	-	-
Ti-1.5Ni	A	-	-	-
Ti-10V	-	-	-	-
<u>Aluminum Base</u>				
2024-T3	-	-	-	-
6061-T6	-	-	-	-
5005	*	X	X	-
<u>Copper Base</u>				
Copper	-	-	-	-
Cu-2Fe	-	-	-	-
90-10 Brass	-	-	-	-
70-30 Brass	-	-	-	-
90-10 Cupronickel	-	-	-	-
70-30 Cupronickel	-	-	-	-
<u>Molybdenum Base</u>				
TZM	-	-	-	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate ≥ 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- no data available

*Specimens covered with adherent scale; other experience justifies a C or D rating

Source: Carter and Cramer 1974; Needham 1976; Needham et al. 1977

TABLE 4.14-5. EAST MESA CORROSION SCREENING RESULTS FOR FIRST FLASH STEAM

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel (AISI 1020)	B	N	X	N
AISI 4130	B	N	X	N
AISI 302	-	-	-	-
AISI Type 316L	A	N	N	N
AISI Type 430	A	X	X	N
Sandvik 3RE60	-	-	-	-
E-Brite 26-1	A	N	N	N
Carpenter 20	-	-	-	-
<u>Nickel Base</u>				
Monel 400	-	-	-	-
Inconel X-750	-	-	-	-
Inconel 625	A	-	-	N
Hastelloy S	A	R	-	N
Hastelloy G	-	-	-	-
Hastelloy C-276	A	-	-	N
<u>Titanium Base</u>				
Titanium	-	-	-	-
Ti-1.7W	-	-	-	-
Ti-1.5Ni	A	R	-	N
Ti-10V	-	-	-	-
<u>Aluminum Base</u>				
2024-T3	-	-	-	-
6061-T6	-	-	-	-
5005	C	X	X	-
<u>Copper Base</u>				
Copper	-	-	-	-
Cu-2Fe	-	-	-	-
90-10 Brass	-	-	-	-
70-30 Brass	-	-	-	-
90-10 Cupronickel	-	-	-	-
70-30 Cupronickel	-	-	-	-
<u>Molybdenum Base</u>				
TZM	-	-	-	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but < 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate ≥ 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- R - general roughening of surface
- - no data available

Sources: Carter and Cramer 1974; Needham 1976; Needham et al. 1977

TABLE 4.14-6 EAST MESA CORROSION SCREENING RESULTS FOR SECOND FLASH STEAM

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel (AISI 1020)	B	N	X	N
AISI 4130	B	N	X	-
AISI 302	-	-	-	-
AISI 316L	A	X	-	N
AISI 430	A	X	-	-
Sandvik 3RE60	-	-	-	-
E-Brite 26-1	A	N	N	N
Carpenter 20	A	X	-	-
<u>Nickel Base</u>				
Monel 400	-	-	-	-
Inconel X-750	-	-	-	-
Inconel 625	A	-	-	-
Hastelloy S	A	-	-	-
Hastelloy G	-	-	-	-
Hastelloy C-276	A	-	-	-
<u>Titanium Base</u>				
Titanium	-	-	-	-
Ti-1.7W	-	-	-	-
Ti-1.5Ni	A	-	-	-
Ti-10V	-	-	-	-
<u>Aluminum Base</u>				
2024-T3	-	-	-	-
6061-T6	-	-	-	-
5005	A	-	-	-
<u>Copper Base</u>				
Copper	-	-	-	-
Cu-2Fe	-	-	-	-
90-10 Brass	-	-	-	-
90-10 Cupronickel	-	-	-	-
70-30 Cupronickel	-	-	-	-
<u>Molybdenum Base</u>				
TZM	-	-	-	-

Key to Table

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but < 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate ≥ 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- R - general roughening of surface
- - no data available

Sources: Carter and Cramer 1974; Needham 1976; Needham et al. 1977

TABLE 4.14-7. COMPOSITION OF MESA 6-1 FLUID USED IN LABORATORY TESTS

COMPONENT	CONCENTRATION
<u>Key Species (ppm):</u>	
pH	7.60
Chloride (Cl^-)	18,000
Sulfate (SO_4^-)	16
Bicarbonate (HCO_3^-)	—
Carbonate (CO_3^{2-})	—
Carbon dioxide (CO_2)	— ^a
Hydrogen sulfide (H_2S)	<1.0 ^a
Ammonia (NH_3)	38.8
<u>Other Species (ppm):</u>	
Silica (SiO_2)	101
Sodium (Na)	11,000
Potassium (K)	1,430
Calcium (Ca)	1,370

^aPrior history of liquid indicates that these values are probably zero.

—: No data available

Source: Carter and Cramer 1974

Laboratory tests were run at 221°F for 15 days in aerated and de-aerated media. Aeration was by constant air bubbling, and deaeration was by continuous helium purge. The noncondensable gases (carbon dioxide, hydrogen sulfide, ammonia, etc.) were removed by the flashing and the purging. The concentrations of sulfide and carbonate species were also probably lower in the laboratory fluid than in the actual wellhead fluid because gaseous hydrogen sulfide and carbon dioxide were lost in the flashing and purge gas. The solution pH (6 to 7) was less acidic than the actual wellhead brine, which was about 5.7.

Results and Discussion

The results of the laboratory tests are presented in Table 4.14-8. Uniform corrosion results from field tests (discussed in Section 4.14.2.2) are also presented in this table for ease of comparison.

These laboratory tests are useful for establishing guidelines and identifying potential problems, but the tests did not directly simulate actual site conditions for the following reasons:

1. Laboratory test temperatures (221°F) were lower than wellhead temperatures (266°F).
2. Laboratory solutions did not contain non-condensable gases.
3. The pH of the laboratory solution was higher than that of the natural wellhead fluid.

The results presented in Table 4.14-8 are discussed below.

All of the alloys had good uniform corrosion resistance (less than 5 mpy) in the deaerated fluid except carbon steel and 70-30 cupronickel. These corroded moderately (5 to 10 mpy). Carbon steel, AISI 4130 steel, 2024-T3 aluminum, copper, Cu-2Fe, and 70-30 cupronickel corroded severely (greater than 10 mpy) when the fluid was aerated. Titanium and its alloys, the Hastelloys, the Inconels, Sandvik 3RE60, AISI 302 stainless steel, and AISI 316L stainless steel had very good resistance to general corrosion (less than 1 mpy), and the corrosion rates were not significantly affected by aeration (Needham et al. 1977), as shown in Table 4.14-8.

Pitting was detected only on aluminum alloy 2024-T3 in the aerated solution: pits 60 mils deep were detected. Crevice corrosion in deaerated fluid was detected only on AISI 316L stainless steel, but in aerated fluid this corrosion was detected on AISI 302, AISI 316L, Sandvik 3RE60, Monel 400, titanium, 90-10 brass, and 70-30 brass. Severity of attack is detailed in Table 4.14-8. The test conditions of pH, temperature, non-condensable gas concentrations, and test duration are such that the laboratory pitting and crevice corrosion results may be misleading. Field tests indicate that metals may be more susceptible to pitting and crevice corrosion in East Mesa fluids than is evidenced by the laboratory tests (Needham et al. 1977).

None of the laboratory specimens showed any evidence of stress corrosion cracking, but the aluminum alloy 6061-T6 showed increased (unquantified) corrosion in the stressed area of the U-bends.

TABLE 4.14-8. RESULTS OF LABORATORY AND FIELD CORROSION TESTS IN EAST MESA WELLHEAD FLUID

MATERIAL TESTED	CORROSION IN NONAERATED FLUID					CORROSION IN AERATED FLUID				COMMENTS
	Field Test: ^a (226°F)	Laboratory Tests ^b (221°F)				Laboratory Tests ^c (221°F)				
	Uniform Corrosion (mpy)	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC	
<u>Iron Base</u>										
Carbon Steel(AISI 1020)	3.2	17.3	N	-	N	40.9	N	-	N	^a 15 day field test at Mesa 6-1 (GRC 1976). ^b BOM laboratory test (15 day) in Mesa 6-1 wellhead fluid without noncondensable gases - degraded by continuous Argon purge ^a ^c BOM laboratory test (15 day) in Mesa 5-1 wellhead fluid without noncondensable gases - aerated with continuous air purge ^a ^d Pitting rate based on maximum pit depth. ^e Increased general corrosion in stressed area of U-bends. ^f <0.1 mpy. ^g >0.1 mpy but <1.0 mpy. ^h >1.0 mpy but <5 mpy. NOTE: Performance of cast (ACI) alloys based on wrought counter-parts.
AISI 4130	1.9	0.2	N	N	N	10.7	N	N	N	
AISI Type 302	-	<0.05	N	N	N	0.1	N	X ^f	N	
AISI Type 316L	<0.05	<0.05	N	X ^f	N	<0.05	N	X ^f	N	
AISI Type 430	0.1	-	-	-	-	-	-	-	-	
Sandvik 3RE60	-	0.4	N	N	N	0.1	N	X ^h	N	
E-Brite 26-1	<0.05	<0.05	N	N	N	<0.05	N	N	N	
Carpenter 20	-	0.1	N	N	N	0.2	N	N	N	
<u>Nickel Base</u>										
Monel 400	-	0.2	N	N	N	2.5	N	X	N	
Inconel X-750	-	<0.05	N	-	N	0.1	N	-	N	
Inconel 625	<0.05	<0.05	N	N	N	<0.05	N	N	N	
Hastelloy S	<0.05	0.1	N	N	N	0.1	N	N	N	
Hastelloy G	-	0.1	N	N	N	0.1	N	N	N	
Hastelloy C-276	<0.05	0.1	N	N	N	0.1	N	N	N	
<u>Titanium Base</u>										
Titanium	-	<0.05	N	N	N	<0.05	N	X ^f	N	
Ti-1.7W	-	<0.05	N	N	N	<0.05	N	N	N	
Ti-1.5Ni	<0.05	<0.05	N	-	N	0.1	N	-	N	
Ti-10V	-	<0.05	N	-	N	<0.05	N	-	N	
<u>Aluminum Base</u>										
2C24-T3	-	4.9	N	-	N	45.4	1400mpy ^d	-	N	
6C61-T6	-	2.1	N	-	e	2.1	N	-	e	
5C05	57.0	-	-	-	-	-	-	-	-	
<u>Copper Base</u>										
Copper	-	1.9	N	-	N	63.1	N	-	N	
Cu-2Fe	-	3.7	N	-	N	11.6	N	-	N	
9C-10 Brass	-	2.2	N	N	N	3.6	N	X ^h	N	
70-30 Brass	-	1.2	N	N	N	4.3	N	X ^h	N	
90-10 Cupronickel	-	0.9	N	N	N	3.7	N	N	N	
70-30 Cupronickel	-	5.7	N	-	N	17.9	N	-	N	
<u>Molybdenum Base</u>										
TZM	-	0.2	N	-	N	3.0	N	-	N	

^aCarter and Cramer 1974KEY TO TABLE

N - Not detected
X - Detected
- - No data available

Sources for column 1: GRC 1976; Needham et al. 1977

Sources for other data: Carter and Cramer 1974

4.14.2.2 Field Corrosion Tests

Method

Ten alloys were tested in a dual flash simulation at East Mesa. Coupons were exposed to wellhead fluid, first and second flash liquid streams, and first and second flash steams from well Mesa 6-1. The compositions of these streams are given in Table 4.14-9. U-bend stress corrosion cracking specimens were exposed to first flash steam.

TABLE 4.14-9. COMPOSITION OF TEST STREAMS FROM WELL MESA 6-1
AT EAST MESA SITE

TEST STREAM	pH	Cl (ppm)	Na (ppm)	K (ppm)	Si (ppm)	Ca (ppm)	Ba (ppm)
Wellhead Fluid	5.6	11,800	6,153	613	129	771	16.8
Separator 1 Fluid	6.8	12,062	5,867	645	125	795	15.9
Separator 2 Fluid	8.1	12,735	6,667	645	135	850	18.8
Separator 1 Steam	5.2	3,000-5,000 ^a	2,803	323	44	300	16.3
Separator 2 Steam	5.7	200-500 ^a	10	82	<10	<10	<.1

^a Data distorted by control valve problems.

Sources: Needham 1976; Needham et al. 1977

All samples were visually inspected after removal from the test environment, descaled, and examined for evidence of microscopic damage such as pitting, crevice corrosion, and chloride stress corrosion cracking (SCC). The corrosion rates were determined by weight-loss measurements of at least four coupons (Needham et al. 1977). These tests were to be included in a 60-day, planned-interval test, but the Mesa 6-1 well failed on the twenty-second day of testing. A massive carbonate scale plug stopped flow from the well. Results were therefore available only for the first fifteen-day interval.

Results and Discussion

The results of in-situ corrosion tests in Mesa 6-1 wellhead fluid, flashed fluids, and flashed steams are given in Tables 4.14-10, 4.14-11, and 4.14-12 respectively. All results are for 15-day exposures.

TABLE 4.14-10. FIELD CORROSION RESULTS IN EAST MESA WELLHEAD FLUID^a

MATERIAL TESTED	CORROSION RESULTS			
	Uniform corrosion (mpy)	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel (AISI 1020)	3.2	N	X	-
AISI 4130	1.9	N ^b	X	-
AISI Type 316L	<0.05	X ^b	N	-
AISI Type 430	0.1	X ^b	N	-
E-Brite 26-1	<0.05	X ^b	N	-
<u>Nickel Base</u>				
Inconel 625	<0.05	X ^b	N	-
Hastelloy S	<0.05	N ^c	N	-
Hastelloy C-276	<0.05	N ^d	N	-
<u>Aluminum Base</u>				
5005	57.0	X	X	-
<u>Titanium Base</u>				
Ti-2Ni	<0.05	N ^c	N	-

^aWellhead fluid was not aerated

^bMicroscopic pits were observed but were too small to measure with an optical microscope

^cGeneral microscopic roughening of the surface

^dNo microscopically detectable corrosion

KEY TO TABLE

N - not detected

X - detected

- - no data available

Sources: Needham 1976; Cramer and Carter 1976;
Needham et al. 1977

TABLE 4.14-11. CORROSION TEST RESULTS IN FIRST AND SECOND FLASHED FLUID
AT EAST MESA

MATERIAL TESTED	NONAERATED FIRST FLASH FLUID ^a				NONAERATED SECOND FLASH FLUID ^b			
	Uniform Corrosion	Fitting	Crevice Corrosion	SCC	Uniform Corrosion	Fitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	2.4	N	X ^d	-	3.3	N	X ^d	-
AISI 4130	1.6	N	X ^d	-	1.2	N	X ^d	-
AISI Type 316L	<0.05	X ^c	-	-	0.1	X ^c	-	-
AISI Type 430	0.5	X ^c	-	-	0.2	X ^c	-	-
E-Brite 26-1	<0.05	X ^c	-	-	0.1	N	-	-
<u>Nickel Base</u>								
Inconel 625	<0.05	-	-	-	<0.05	-	-	-
Hastelloy S	<0.05	-	-	-	<0.05	-	-	-
Hastelloy C-276	<0.05	-	-	-	<0.05	-	-	-
<u>Aluminum Base</u>								
5005	21.4	X ^e	X ^f	-	2.7 ^g	X ^e	X ^f	-
<u>Titanium Base</u>								
Ti-1.5Ni	<0.05	-	-	-	<0.05	-	-	-

^a15-day field test in first flash Mesa 6-1 fluid (pH - 6.8, Cl⁻ - 12,062 ppm)

^b15-day field test in second flash Mesa 6-1 fluid (pH - 8.1, Cl⁻ - 12,735 ppm)

^cMicroscopic pits too small to measure with optical micrometer

^dSome crevice corrosion

^eSevere pitting (unquantified)

^fVery severe crevice corrosion (unquantified)

^gSpecimens covered with hard adherent scale which could not be removed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - No data available.

Sources: Needham 1976; Needham et al 1977

TABLE 4.14-12. CORROSION RESULTS IN FIRST AND SECOND FLASH STEAM AT THE EAST MESA KGRA

MATERIAL TESTED	NONAERATED FIRST FLASH STEAM				NONAERATED SECOND FLASH STEAM			
	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	2.1	N	X ^a	N	3.2	N	X ^a	--
AISI 4130	1.3	N	X	N	2.5	N	X ^a	--
AISI Type 316L	<0.05	X	N	N	0.1	X ^a	--	--
AISI Type 430	<0.05	X ^a	X ^a	N	<0.05	X ^a	--	--
E-Brite 26-1	<0.05	N	N	N	0.1	N	N	--
<u>Nickel Base</u>								
Inconel 625	<0.05	X ^a	N	N	<0.05	--	--	--
Hastelloy S	<0.05	R	N	N	0.1	--	--	--
Hastelloy C-276	<0.05	N	N	N	0.05	N	N	--
<u>Aluminum Base</u>								
5005	29.0	X ^b	X ^b	N	<0.05	X	X	--
<u>Titanium Base</u>								
Ti-2Ni	<0.05	R	N	N	<0.05	--	--	--

^aObserved attack too slight to measure^bObserved attack severe (unquantified)KEY TO TABLE

N - indicated form of corrosion not detected

X - indicated form of corrosion detected

- - data not available.

R - general roughening of surface

Sources: Needham 1976; Needham et al. 1977

The corrosion rates did not appear to be affected by the sample orientation (normal or tangential) in the flow of the fluid or steam. Hastelloy C-276, Hastelloy S, Inconel 625, Ti-2Ni, and AISI 316L showed excellent resistance to uniform corrosion in all five environments; corrosion rates were less than 0.1 mpy. Microscopic examination of these materials, however, showed that only Hastelloy C-276 exhibited no visual evidence of corrosion. AISI 316L and Inconel 625 showed localized corrosion in the form of very shallow pits. These were too small to be measured with an optical micrometer (less than 0.1 mil). A general surface roughening was noted on Ti-2Ni and Hastelloy S coupons.

E-Brite 26-1 and AISI 430 had excellent resistance to corrosion in the flashed fluid and flashed steam environments. There was only fair resistance to corrosion in the wellhead fluid. Microscopic examination of all AISI 430 samples showed the same shallow pitting observed on AISI 316L samples. Only those E-Brite 26-1 samples exposed to the wellhead fluid and to the concentrated fluid from Separator #1 developed shallow pits. There was no microscopic evidence of corrosion for E-Brite 26-1 samples either in the steam environments or in the concentrated fluid from Separator #2.

Both the 1020 carbon steel and 4130 steel had fair resistance (less than 5 mpy) to uniform corrosion in the five environments even though the microscopic examination showed uniform corrosion attack (Needham et al. 1977).

The corrosion resistance of aluminum 5005 in each of the five environments was poor (greater than 20 mpy). In addition to high uniform corrosion rates, the aluminum samples were severely pitted and showed a high susceptibility to crevice corrosion (Needham et al. 1977).

None of the stress-corrosion U-bend samples exposed for 22 days in the steam from Separator #1 showed evidence of stress corrosion cracking.

In near-neutral pH, low-salinity geothermal fluids, 1020 carbon steel and 4130 steel appear to have value as construction materials. Their corrosion rates were not excessive, and they are low-cost materials. Aluminum alloys cannot be utilized in geothermal environments due to their low resistance to uniform corrosion, pitting, and crevice corrosion in these chloride environments (Needham et al. 1977).

4.14.2.3 Effect of Acidification and Cooling

Preliminary tests (Shannon 1977; 1978) have been performed at East Mesa to evaluate the effects of acidification and temperature on the uniform corrosion of three low alloy steels (AISI 1010, AISI 4130, ASTM A53B) and two stainless steels (AISI 410 and E-Brite 26-1) in Mesa 6-1 wellhead fluid. The test conditions were as follows:

1. 302°F and pH 5.6 to 5.8 (normal conditions).
2. 122°F and pH 5.6 to 5.8.
3. 302°F and pH 4.6 to 4.8.

Lower temperature fluids were obtained by passing fluid through cooling coils, and lower pH was obtained by acid injection. Uniform corrosion rates were determined by weight loss.

Results are presented in Table 4.14-13. These results show that reducing the temperature from 302°F to 122°F causes a twofold to fourfold decrease in the corrosion rates of carbon and low alloy steels, while no effect on the corrosion of AISI 410 and E-Brite 26-1 was observed.

Acidification of the 302°F fluid from pH 5.7 to pH 4.7 caused a threefold to fourfold increase in the corrosion rates of carbon and low alloy steels. This illustrates the pH dependence of the corrosion rate for these alloys. No change was observed for the two stainless steels, AISI 410 and E-Brite 26-1.

4.14.2.4 Field Tests with Nonmetallic Materials

See Section 5.1 for information concerning low temperature-low salinity tests at East Mesa using polymer cement.

4.14.3 Operating Experience

The desalting experiment at East Mesa provides useful information about a direct utilization system. Much of the experience is also transferable to flashed steam binary or direct binary electric systems.

4.14.3.1 Bore and Wellhead Equipment

No serious problems with corrosion of well casing and wellhead equipment have been reported at this KGRA. Calcite precipitation at the flash zone of the Mesa 6-1 well has caused problems (Needham, et al. 1976).

During the desalting tests at East Mesa, corrosion of process equipment was not a major problem. Carbon dioxide was released from the brine upon flashing, causing the brine to become alkaline (pH 8 to 9) and reducing the potential attack on steel. Additionally, the wellhead fluid was free of dissolved oxygen. As a result, process piping and vessels exposed to brine had little uniform corrosion (Suemoto 1977).

The original, single-effect, vertical tube evaporator (VTE) unit consisted of 0.71 inch O.D. carbon steel (A-106 GrB) tubes with walls 95 mils thick. Wellhead liquid from Mesa 6-2 entered the tube side, while

TABLE 4.14-13. EFFECT OF TEMPERATURE AND ACIDIFICATION ON GENERAL CORROSION AT EAST MESA

MATERIAL TESTED	Mesa 6-1 fluid ^a 302°F	Mesa 6-1 fluid ^a 122°F	Mesa 6-1 fluid ^a 302°F
	pH 5.6 - 5.8 (mpy)	pH 5.6 - 5.8 (mpy)	pH 4.6 - 4.8 (mpy)
AISI 1010	6.0	1.7	25
AISI 4130	6.8	3.5	22
ASTM A53B	5.4	1.8	15
AISI 410	1.3	1.3	1.8
E-Brite 26-1	0.1	0.3	0.1

^aSilica = 300 ppm, Chloride = 13,330 ppm, Hydrogen sulfide = 1.3 ppm,
Oxygen less than 10 ppb

Source: Shannon 1978

steam from Mesa 6-1 was admitted to the shell side of the unit. Further tests were run using liquid and steam from Well 6-2 after flashing in the wellhead separator. Although no silica scale developed in this single effect, silica precipitation remained a potential problem for certain operating conditions in multistage effects. No severe (not quantified) cases of uniform or localized corrosion were observed; however, a layer of magnetite formed on the steam side of the tubes (USBR 1977).

The major problem during these tests on the VTE was the unacceptable loss of heat transfer. The loss was due to (1) buildup of magnetite

on the steam side and (2) scale deposition on the liquid side of the evaporator tubes. The barium sulfate scale on the liquid side, which formed when using fluid from well Mesa 6-1, was very adherent. Wellhead fluid from the Mesa 6-2 well caused the formation of calcium carbonate scale. Flashing the fluid prior to introduction to the VTE reduced the scaling by an unquantified amount (USBR 1977).

The carbon steel tubes were replaced with 90-10 cupronickel tubes. The external (steam) surface of these tubes was severely (not quantified) attacked by hydrogen sulfide in the steam. Heavy deposits (copper and nickel sulfides) caused an unacceptable heat transfer decrease.

After the VTE system was modified to the three-effect-plus-condenser configuration, additional testing was conducted. Carbon steel and 90-10 cupronickel tubes performed as previously described. Titanium tubes showed no corrosion product scale.

Inhibitors to control calcium carbonate and barium sulfate scaling were tested. Three commercial polyphosphonate treatments and a chelating agent (unspecified) were tested. Dearborn 8010®, an aminomethylene phosphonate compound, was selected for further study. This scale inhibitor effectively controlled scale when used at a concentration of 5 ppm (USBR 1977; Suemoto 1977).

The Multistage Flash (MSF) unit was run under two test conditions, both using fluid from Mesa 6-2. The first condition was an inlet temperature of 270°F, and the second condition was 210°F. The heat transfer tubing was E-Brite 26-1 (26Cr-1Mo stainless steel). Examination of the unit after each month-long test revealed that the entire inner surface was covered with a calcium carbonate scale containing minor amounts of silica and iron. The tube side velocities were limited to 3.5 to 4 ft/sec and could have compounded the scaling problem (Boegli, Suemoto, and Trompeter 1977). No degradation of the E-Brite 26-1 tubing was observed (Suemoto 1977).

The impeller of one high-speed, waste fluid reinjection pump was damaged by cavitation. The composition of the impeller is not known. With this exception, no deterioration of centrifugal pumps made of either AISI 316 stainless steel or Ni-Al bronze (unspecified grade) was observed. However, major operating problems occurred because of failure of pump seals or packing. The problem was attributed to buildup of abrasive salt crystals on sealing surfaces. It was suggested that purging the seals with water would solve this problem (Suemoto 1977).

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4.15 HEBER, CALIFORNIA

The Heber KGRA is located in the Salton Trough in southern California as shown in Figure 4.15-1. Geothermal well depths range from 2950 feet to 10,825 feet, and the average bottom hole temperature is about 356°F. Temperatures of 374°F have been observed (Muffler 1978). Construction of a 45 MW (net output) power plant at Heber is planned. The plant will be a direct binary system with a hydrocarbon (80 mole percent isobutane, 20 mole percent isopentane) secondary fluid.

4.15.1 Fluid Chemistry

The Heber geothermal fluid is a neutral chloride water of about 14,000 to 16,000 ppm total dissolved solids. There are only traces of non-condensable gases. Table 4.15-1 gives the composition of unflashed fluid from two wells at Heber. These wells probably represent the range of concentrations from this resource.

4.15.2 Corrosion Tests

Limited corrosion testing has been done at the Heber KGRA. The results are summarized in Table 4.15-2. Scale and corrosion products were not removed before weight losses were determined. Corrosion rate calculations based on weight loss are therefore affected by the corrosion products on the coupons.

4.15.2.1 Test Conditions

Heat exchanger and in-situ coupon testing was conducted at the Heber, California geothermal site (Syrett et al. 1977). Coupons of potential construction materials were exposed to flowing fluid from the Nowlin No. 1 well for 42 days. Fluid composition is given in the second column of Table 4.15-1. After exposure, the coupons were examined, and the weight change was determined. However, the coupons were not cleaned or descaled. The uniform corrosion rates are probably not accurate. No significant weight loss was found, except for carbon steel.

4.15.2.2 Results and Discussion

The data in Table 4.15-3 indicate a uniform corrosion rate of about 2.5 mpy for carbon steel. This value compares reasonably well with the uniform corrosion rate of 3.2 mpy for carbon steel at East Mesa. Compositions of these two fluids are similar. Of the materials tested, AISI 316L and E-Brite 26-1 showed signs of local corrosion (small pits). This pitting behavior is similar to results obtained at East Mesa (Needham et al. 1976).

FIGURE 4.15-1. LOCATION OF HEBER GEOTHERMAL RESOURCE

TABLE 4.15-1 COMPOSITION OF GEOTHERMAL FLUID FROM TWO WELLS AT
HEBER, CALIFORNIA KGRA^{a,d}

FLUID COMPONENTS		CONCENTRATION IN WELL NOWLIN NO. 1	CONCENTRATION IN WELL HOTZ NO. 2
Key Species (ppm):			
pH		7.1	7.4
Chloride	(Cl ⁻)	9000	8242
Sulfate	(SO ₄ ⁻²)	1000	148
Hydrogen	(H ₂ S)	2 ^b	- ^c
Sulfide			
Bicarbonate	(HCO ₃ ⁻)	20	-
Carbonate	(CO ₃ ⁻²)	4	-
Carbon dioxide	(CO ₂)	100-180 ^b	-
Ammonia	(NH ₃)	5-13 ^b	-
Other Species (ppm):			
Silica	(SiO ₂)	120	187
Sodium	(Na)	3600	4720
Potassium	(K)	360	231
Lithium	(Li)	6.6	4.1
Calcium	(Ca)	880	1062
Barium	(Ba)	-	3.0
Magnesium	(Mg)	2.4	23
Fluorine	(F)	1.6	1.5
Aluminum	(Al)	0.04	12
Boron	(B)	4.8	8
Copper	(Cu)	0.2	0.4
Iron	(Fe)	0.9	5
Magnanese	(Mn)	-	0.9
Lead	(Pb)	0.1	0.6
Strontium	(Sr)	-	42
Zinc	(Zn)	0.7	0.1
Total Dissolved Solids		14100	16330

^aThere are only traces of carbon dioxide, hydrogen sulfide, and other noncondensable gases.

^bSource: Syrett et al. 1977

^c -: Data not available

^dOther data from Cosner and Apps 1978

TABLE 4.15-2 MATERIAL SCREENING FOR HEBER WELLHEAD FLUID

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel	B	N	-	-
AISI Type 316L	A	X	-	-
Haynes Alloy 20 Mod	A	N	-	-
Carpenter Alloy 20Cb3	A	N	-	-
E-Brite 26-1	A	X	-	-
<u>Nickel Base</u>				
Inconel 625	A	N	-	-
Hastelloy G	A	N	-	-
Hastelloy C - 276	A	N	-	-
<u>Titanium Base</u>				
Titanium (Ti 50A)	A	N	-	-
TiCode 12	A	N	-	-

Note: Specimens were not descaled before weight-loss determination.

Key to Table

- A - Uniform corrosion rate ≤ 1 mpy
- B - Uniform corrosion rate > 1 mpy but ≤ 10 mpy
- C - Uniform corrosion rate > 10 mpy but < 50 mpy
- D - Uniform corrosion rate ≥ 50 mpy
- N - Indicated form of corrosion not detected
- X - Indicated form of corrosion detected
- - No data available

Source: Syrett et al. 1977

TABLE 4.15-3. CORROSION TEST RESULTS FOR WELLHEAD FLUID AT
HEBER, CALIFORNIA

MATERIAL TESTED ^a	NON-AERATED FLUID			
	Weight Change ^b μg/cm ² day	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Carbon Steel	-145	N	-	-
AISI Type 316L	+ 0.24	X ^c	-	-
Haynes Alloy 20 Mod	+ 1.4	N	-	-
Carpenter Alloy 20Cb3	+ 0.48	N	-	-
E-Brite 26-1	+ 0.48	X ^c	-	-
<u>Nickel Base</u>				
Inconel 625	+ 1.4	N	-	-
Hastelloy G	+ 0.24	N	-	-
Hastelloy C-276	0.00	N	-	-
<u>Titanium Base</u>				
Titanium (Ti 50A)	+ 0.71	N	-	-
TiCode 12	+ 2.9	N	-	-

^aCoupons exposed to flowing Nowlin #1 wellhead fluid for 42 days

^bWeight loss determined without descaling of specimens

^cFew small pits

Source: Syrett et al. 1977

KEY TO TABLE

N - Indicated form of
corrosion not detected
X - Indicated form of
corrosion detected
- - No data available

4.15.3 Heat Exchanger Tests

Short-term (500 hr) tests of a tube-in-shell heat exchanger were performed at the Heber site by the San Diego Gas and Electric Company. No quantitative corrosion data were available.

"A small-scale, tube-in-shell heat exchanger with four sections in series was tested with geothermal brine from the Nowlin No. 1 well at Heber, California, in the Imperial Valley in late 1974. The brine inlet temperature was approximately 355°F and contained 14,500 ppm dissolved solids.

Three tube materials commonly used in heat exchangers were tested. These materials were titanium, carbon steel, and 90 percent copper - 10 percent nickel. No corrosion was observed on the titanium tubes after 560 hours of testing.

The carbon steel tubes sustained slight pitting and decarburization during 560 hours exposure to the geothermal brine. Some corrosion of the copper-nickel tubes was evident after exposure for 200 hours. The copper-nickel tubes corroded at a much more rapid rate than the carbon steel." (Lombard 1976).

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4.16 KLAMATH FALLS, OREGON

Klamath Falls, Oregon, is located in south central Oregon about 20 miles north of the California border, as shown in Figure 4.16-1. The hot artesian waters of this area have been used for over 100 years. It is known that Indians used the waters for bathing and cooking. The natural hot springs were developed into spas. Homes have been heated with these waters since before the turn of the century. Since that time, extensive use has been made of this resource. Table 4.16-1 lists a variety of applications of geothermal energy in and around Klamath Falls.

Wells drilled in this KGRA produce waters ranging from about 72°F to 210°F. It is expected that deeper wells (approximately 3000 ft.) could produce steam/water near 230°F (Lineau 1977).

Over 500 homes are heated by about 450 wells. Generally, a two-inch diameter, U-shaped steel pipe, called a "down hole" heat exchanger, is used to heat city water circulated by natural convection. Larger heating systems, such as those of the Oregon Institute of Technology (OIT) or Maywood Industries, utilize fluid pumped from their wells (Johnson 1977). Plate heat exchangers are now utilized. Three are on-line, and several more are planned.

Installations include the use of geothermal fluid to raise prawns, pasteurize milk, melt snow, operate greenhouses, and dehydrate food products. The current practice is to reinject used fluid, so that it may be recycled. Another approach has been to heat antifreeze or oil with the geothermal fluid and then use the oil or antifreeze for heating or processing.

4.16.1 Fluid Chemistry

Geothermal fluid from several sources at the Klamath Falls KGRA has been analyzed. Table 4.16-2 is a tabulation of the range of test results and a typical analysis of the fluid at room temperature. The geothermal fluid at Klamath Falls lends itself to direct utilization. The high pH is favorable, and it is less aggressive to ferrous materials than some geothermal fluids. The low silica content minimizes silica scaling. The low chloride level is also less detrimental to stainless steels than other waters. The presence of hydrogen sulfide, and at some installations, oxygen, causes corrosion of copper-bearing and ferrous components. Hydrogen sulfide may scavenge some of the oxygen present in some systems and decrease oxygen-initiated corrosion.

4.16.2 Materials Tests

The majority of materials studies have been in the form of operating experience. Coupons of various materials have been tested to a limited extent.

FIGURE 4.16-1. LOCATION OF KLAMATH FALLS GEOTHERMAL RESOUCUE

4.16.2.1 Tests by the International Nickel Company and the Oregon Institute of Technology

Corrosion coupons of the materials shown in Table 4.16-3 have been prepared by the International Nickel Company (INCO) and the Oregon Institute of Technology (OIT). Table 4.16-4 presents a materials screening summary of those tests.

TABLE 4.16-1. GEOTHERMAL INSTALLATIONS AT THE KLAMATH FALLS, OREGON, KGRA

INSTALLATION	USE	SYSTEM	TYPE ^a	TEMP °F
Oregon Institute of Technology (OIT)	Raise Prawns	Pump & Waste	Mono	192
Balsiger Motors	Wash Cars	Pump & Waste	Mono	160
OIT ⁹	Heat Greenhouse	Pump & Waste	Mono	187
Klamath Greenhouses	Heat Greenhouse	Pump & Waste	Mono	195
Balsiger Motors	Space Heating	Pump & Waste	Mono	160
OIT	Space Heating	Pump & Waste	Mono	192
Kingswood Apartment	Space Heating	Pump & Waste	Mono	126
Maywood Industries	Space Heating	Pump & Waste	Mono	
Medo-Bel Dairy	Pasturize Milk	Pump & Waste	Mono	181
Shadow Hill Apt.	Space Heating	Pump, Circulate, Waste	Mono	166
Western Polymer	Potato Starch Extraction	^b	Mono	^b
^b	Onion Dehydration	Pump & Reinject	Mono	230 ^b
^b	Alfalfa Dehydration	Pump & Reinject	Mono	220 ^b
Industrial Park (19 Sites)	Space Heating and Process Heat	Pump & Reinject	Mono	190 ^b

(Cont.)

TABLE 4.16-1. (Continued)

INSTALLATION	USE	SYSTEM	TYPE ^a	TEMP °F
Presbyterian Hospital	Space Heating	Pump, Circulate, Waste	Bi (antifreeze)	195
Klamath Union High School	Space Heating	Pump, Circulate, Waste	Bi	160
Klamath Falls District Heating	Space Heating	Pump & Reinject	Bi	^b —
State Hwy. Dept.	Snow Melting	"Downhole" Heat Exchanger	Bi (antifreeze)	>120
500 Private Homes	Space Heating	"Downhole" Heat Exchanger	Bi	100-230 Variable
Klamath Union High School	Heat Swimming Pool & Deck	"Downhole" Heat Exchanger in re- injection well	Bi	Variable
Klamath Ice & Storage Co.	Floor Heating	"Downhole" Heat Exchanger	Bi (oil)	Unknown

^aSystem types are defined as follows:

Mono: Monofluid system - geothermal fluid is circulated to all parts of the system where geothermal heat is utilized.

Bi: Bifluid system - an intermediate isolation heat exchanger is used to transfer geothermal heat to a secondary working fluid, which then transports the heat to appropriate points in the system.

^bProposal Stage Only. Name of user uncertain. Resource temp. unknown. Temp. value shown (if any) is that temp. required for process.

TABLE 4.16-2. COMPOSITION OF KLAMATH FALLS KGRA FLUID

COMPONENT	CONCENTRATION	
	Range	Typical
<u>Key Species</u>		
	ppm	ppm
pH	7.65-8.71	8.6
Chloride (Cl ⁻)	47.5-61	51
Sulfate (SO ₄ ⁻²)	325-413	330
Bicarbonate (HCO ₃ ⁻)	0-84.2	20
Carbonate (CO ₃ ⁻²)	14-23	15
Hydrogen sulfide (H ₂ S)	trace-1.5	1.5
Ammonium ion (NH ₄ ⁺)	0.54-1.3	1.3
Oxygen (O ₂)	0-0.06	0-0.02
<u>Other Species</u>		
TDS ^a	791-816	795
Silicon (Si)	43-67.4	48
Sodium (Na)	197-331	205
Calcium (Ca)	13-29	26
Nitrate (NO ₃ ⁻)	4.8-5.0	4.9
Potassium (K)	3.5-4.8	4.3
Fluorine (F)	1.3-1.6	1.5
Iron (Fe)	0.01-0.3	0.3

^aTotal Dissolved Solids

Source: Ellis 1980a

Test Methods and Conditions

Coupons were 2.233-inch diameter disks. They were separated and insulated by Teflon washers during testing. In the galvanic corrosion couples, five different materials were coupled to a steel washer to simulate dissimilar metal contact in a well.

TABLE 4.16-3. MATERIALS TESTED AT KLAMATH FALLS KGRA

MATERIAL	PERFORMED BY
AISI Type 304 Stainless Steel	INCO, OIT
AISI Type 316 Stainless Steel	INCO
Carpenter 20Cb3 Stainless Steel	INCO
Incoloy Alloy 800 Stainless Steel	INCO
Oxygen Free Copper	INCO, OIT
Ni-resist Type 2	INCO
Red Brass	INCO, OIT
High Strength Low Alloy United States Steel-CorTen	INCO, OIT
Grade 6061 Aluminum	INCO, OIT
AISI Type 1010 Carbon Steel	INCO, OIT
Gray Cast Iron	INCO

Source: Lund 1976

The corrosion coupons were suspended in six Klamath Falls wells for 191 to 192 days. The locations of the coupons within the wells during testing are shown in Table 4.16-5. Temperatures experienced by the coupons varied from well to well. One "low" temperature well was used, having a range of 75° to 117°F. The remaining "hot" wells ranged from 110° to 210°F. The coupons were analyzed by INCO and OIT personnel.

To study the effect of stray electrical currents on downhole heat exchangers, samples of steel wire were suspended at the waterline in three wells for a three-day period. Four wires were tested in each case: no voltage, AC voltage, -DC voltage, and +DC voltage. The weight change of each wire sample was measured to evaluate its performance.

TABLE 4.16-4. MATERIAL SCREENING TABLE FOR THE KLAMATH FALLS KGRA

MATERIAL TESTED	SUBMERGED (non-aerated fluid)				WATERLINE (aerated fluid)				AIR SPACE (moist air above fluid)			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Cast Irons</u>												
Gray	B	X	X	--	C	X	N	--	B	N	N	--
Ni-resist-2	A	N	X	--	B	X	N	--	A	X	--	--
<u>Low Alloy Steels</u>												
Carbon (1010)	A	X	X	--	B	X	X	--	A	X	X	--
CorTen	A	X	X	--	B	X	X	--	B	X	X	--
<u>Stainless Steels</u>												
Type 304	A	N	X	--	A	X	X	--	A	N	N	--
Type 316	A	N	N	--	A	X	X	--	A	N	N	--
Carpenter 20Cb3	A	N	N	--	A	X	X	--	A	N	N	--
<u>Other Alloys</u>												
Copper	A	X	X	--	B	X	X	--	A	X	X	--
Red Brass	A	X	X	--	B	N	X	--	A	X	X	--
Incoloy 800	A	N	N	--	A	X	X	--	A			
Aluminum 6061	A	X	X	--	B	X	X	--	A	X	N	--

KeyA uniform corrosion rate ≤ 1 mpyB uniform corrosion rate > 1 mpy but ≤ 10 mpyC uniform corrosion rate > 10 mpy but < 50 mpyD uniform corrosion rate ≥ 50 mpy

N indicated form of corrosion not detected

X indicated form of corrosion detected

— no data available

SOURCE: Lund 1976

TABLE 4.16-5. SUMMARY OF MATERIALS TESTS IN KLAMATH FALLS WELLS

MATERIAL TESTED	LOCATION ^a		
	Submerged	Waterline	Air Space
SS 304	8	2	1
SS 316	5	1	1
Carpenter 20CB-3	5	1	1
Incoloy 800	5	1	1
Brass-Red	8	2	1
Ni-resist-2	5	1	1
Copper	8	2	1
6061 Aluminum	8	2	1
AISI 1010 Steel	8	2	1
USS CorTen Steel	8	2	1
Gray Cast Iron	5	1	1
Polymer Concrete ^b	48	---	---
Iron Wire (impressed voltage) ^b	---	3	---
1010 + 304	1	---	---
1010 + Brass	1	---	---
1010 + Copper	1	---	---
1010 + Aluminum	1	---	---
1010 + CorTen	1	---	---

^aNumbers shown indicate number of duplicate samples used in test

^bIndividual Samples. Results discussed in Section 5.

---: No data available

Source: Lünd 1976

Results and Discussion

Corrosion tests results for submerged coupons, coupons at the waterline, and coupons in the airspace above the waterline are presented in Tables 4.16-6 through 4.16-8. Table 4.16-9 gives the impressed voltage tests while Table 4.16-10 gives results of galvanic couple tests.

TABLE 4.16-6 INCO/OIT CORROSION TEST RESULTS: COUPONS SUBMERGED

MATERIALS TESTED	Uniform Corrosion ^a (mpy)	Pitting ^b (mpy)	Crevice Corrosion ^c (mpy)	SCC
<u>Cast Irons</u>				
Gray	1.0	6	5	-
Ni-Resist Type 2	0.1	I	11	-
<u>Steels</u>				
AISI 1010	0.6	6	65	-
CorTen	0.6	21	40	-
<u>Stainless Steels</u>				
Type 304	0.0	I	0	-
Type 316	0.0	0	0	-
Carpenter 20Cb3	0.0	0	0	-
<u>Other Alloys</u>				
Incoloy 800	0.0	0	0	-
Red Brass	0.2	I	I	-
Copper	0.3	I	6	-
Aluminum 6061	0.9	145	67	-

^a average of six wells

^b based on maximum pit depth

^c based on maximum crevice depth

I - incipient

--- no data available

Source: Lund 1976

TABLE 4.16-7 INCO/OIT CORROSION TEST RESULTS: COUPONS AT WATERLINE

MATERIALS TESTED	Uniform Corrosion ^a (mpy)	Pitting ^b (mpy)	Crevice Corrosion ^c (mpy)	SCC
<u>Cast Irons</u>				
Gray	12.6	38	17	-
Ni-Resist Type 2	2.3	23	21	-
<u>Steels</u>				
AISI 1010	8.8	69	36	-
CorTen	8.4	>93 ^d	38	-
<u>Stainless Steels</u>				
Type 304	0.2	4	I	-
Type 316	0.1	I	I	-
Carpenter 20Cb3	0.0	I	I	-
<u>Other Alloys</u>				
Incoloy 800	0.1	I	0	-
Red Brass	3.6	19	8	-
Copper	4.6	15	4	-
Aluminum 6061	1.5	38	78	-

^a average of six wells

^b based on maximum pit depth

^c based on maximum crevice depth

^d perforated

I - incipient

Source: Lund 1976

TABLE 4.16-8. INCO/OIT CORROSION TEST RESULTS: COUPONS IN AIRSPACE
ABOVE WATERLINE

MATERIALS TESTED	Uniform Corrosion ^a (mpy)	Pitting ^b (mpy)	Crevice Corrosion ^c (mpy)	SCC
<u>Cast Irons</u>				
Gray	2.7	0	0	-
Ni-Resist Type 2	0.2	0		-
<u>Steels</u>				
AISI 1010	0.7	6	11	-
CorTen	1.5	10	13	-
<u>Stainless Steels</u>				
Type 304	0.0	0	0	-
Type 316	0.0	0	0	-
Carpenter 20Cb3	0.0	0	0	-
<u>Other Alloys</u>				
Incoloy 800	0.0	0	0	-
Red Brass	0.1	0	0	-
Copper	0.1	I	3	-
Aluminum 6061	0.3	2	0	-

^a average of six wells

^b based on maximum pit depth

^c based on maximum crevice depth

I - incipient

--- no data available

Source: Lund 1976

TABLE 4.16-9. SUMMARY OF IMPRESSED VOLTAGE CORROSION TEST RESULTS
(AFTER SAMPLE CLEANING)

IMPRESSED VOLTAGE	WELL TEMPERATURE					
	75°F		153°F		198°F	
	% wt. change	volts	% wt. change	volts	% wt. change	volts
No Current	+0.62	---	-0.13	---	-0.04	---
AC ^a	+0.39	14	-1.36	9.3	-0.40	4.4
+DC ^a	-8.49	3.2	-6.64	0.5	-8.97	+0.2
-DC ^a	+0.40	2.6	-0.01	-1.60	-0.24	1.05

^aCurrent not measured

Source: Lund 1976

TABLE 4.16-10. RESULTS OF GALVANIC CORROSION TEST (SUBMERGED COUPONS)

GALVANIC COUPLE	UNIFORM CORROSION RATE (mpy)	
	AISI 1010	Other Alloy
AISI 1010 + Type 304	0.29	0.01
AISI 1010 + Red Brass	0.22	0.12
AISI 1010 + Copper	0.29	0.18
AISI 1010 + Aluminum	0.24	0.09
AISI 1010 + CorTen	0.23	0.14

Source: Lund 1976

Corrosion is most severe at the waterline (in aerated fluid). Corrosion at the waterline is generally an order of magnitude greater than coupon corrosion in moist air or air-free fluid. Carbon steel, currently the most widely used material, exhibited an 8.8 mils per year (mpy) corrosion rate at the waterline compared with 0.6 and 0.7 below and above the waterline, respectively.

Pitting and crevice corrosion must be considered in the design of any geothermal system. In this case, Corten steel coupons were perforated when immersed at the waterline. Crevice corrosion to a depth of 20 mils in six months was observed. Aluminum 6061 pitted at more than 145 mpy when submerged.

Lowest overall corrosion rates tended to occur in submerged test coupons. These coupons were exposed to essentially air-free fluid. Corrosion rates ranged from 0.0 to 0.9 mpy.

Stainless steels showed the best overall performance: a 0.0 to 0.2 mils per year corrosion rate, no crevice corrosion, and pitting from 0 to 2 mils maximum depth in six months.

According to Lund (1976) impressed voltages (AC, +DC) have been shown to increase corrosion rates by a factor of 5 to 10. Stray voltages between components of Klamath Falls heating systems have been measured.

Coupon tests indicate that stainless steels should provide the most reliable service as downhole heat exchangers. Grades of steel with greater alloy content than AISI 304 provide added resistance to pitting. Based on these tests, AISI 316 should provide maximum performance at minimum cost.

4.16.2.2 Tests by Radian Corporation with Pacific Northwest Laboratories

A series of material tests was conducted by Radian Corporation and Pacific Northwest Laboratories (PNL) (Ellis 1980a). The joint study determined corrosion behavior for several materials placed in the space heating system at the Oregon Institute of Technology (OIT). The materials included carbon steel (A53B), deoxidized copper (DHP), Admiralty brass (CA 443), AISI 316 stainless steel, and titanium (grade 2).

The uniform corrosion rate of each material was determined in flowing non-aerated fluid and flowing aerated fluid. Pitting, crevice corrosion, and stress corrosion cracking (SCC) were also evaluated.

Method

The coupons for the uniform corrosion test were tubular metal samples with an outer diameter of about 0.750 inches. They were about one inch long with a 0.62 inch I.D. The coupons were separated by nylon spacers

which formed a tight seal against the ends of the coupons. The hollow centers of the spacers had the same diameter as the inner diameter of the coupons; flow through the connected sections of coupons simulated flow through a pipe. Only the inside of each coupon was exposed to geothermal fluid.

The crevice corrosion test coupons were pieces of tubing split lengthwise. A hole approximately 0.25 inches in diameter was drilled in each piece. Both pieces were then bolted together with a titanium bolt insulated with heat shrink tubing. Mica washers prevented contact between the coupon and the head of the nut and bolt.

The coupons for the stress corrosion test were the C-ring type discussed in ASTM Standard G-38 (ASTM 1978). The C-rings were stressed at 100 percent yield strength. They were retained under stress by titanium nuts and bolts insulated with heat shrink tubing and mica washers. The stress corrosion coupons and the crevice corrosion coupons were placed in a chamber separate from the uniform corrosion coupons.

The length and internal diameter of the various coupons were measured to the nearest mil. The coupons were degreased with acetone, vacuum dried, weighed, and placed in the test environments. Table 4.16-2 contains the chemical analyses of the geothermal fluid. Fluid velocity of the non-aerated stream was five feet per sec. at an average temperature of 189°F. Flow in the tubular coupons was turbulent with a Reynold's number (Re) of 71,600. Test duration was 808.5 hours. Oxygen content was zero parts per billion (ppb).

In a second test, air injection was adjusted to produce a dissolved oxygen concentration of 300 ppb. However, after less than 24 hours, the oxygen level dropped to 30 ppb due to plugging of the injection nozzle. This level of dissolved oxygen was maintained throughout the remainder of the 543 hour test. Fluid velocity during this test was 2.9 fps at 189°F. Flow in the tubular coupons was turbulent (Re = 41,300).

After exposure, the coupons were removed from the test environment for evaluation. The tubular coupons were measured for weight loss to calculate the uniform corrosion rates. The crevice coupons were examined at 40X under a stereomicroscope. Pit and crevice depths were measured with an optical micrometer. The C-rings were examined for cracking at 40X under the stereomicroscope.

Results and Discussion

The results of the two tests are given in Table 4.16-11.

Carbon steel had the highest uniform corrosion rates: 1.05 mpy in non-aerated fluid and 4.04 mpy in aerated (30 ppb oxygen) fluid. The rates of the other materials were one-half to one-tenth the uniform rates

TABLE 4.16-11. RESULTS OF PNL/RADIAN CORROSION TESTS AT KLAMATH FALLS

MATERIAL TESTED	NON-AERATED FLUID ^a				AERATED FLUID ^b			
	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion (mpy)	SCC	Uniform Corrosion (mpy)	Pitting	Crevice Corrosion (mpy)	SCC
Carbon Steel (A53B)	1.05	N	13	-	4.04	X ^c	50	-
Deoxidized Copper	1.05	N	X ^d	N	1.91	N	X ^d	N
Admiralty Brass (CA443)	0.43	N	X ^d	N ^e	0.46	N	X ^d	N
AISI 316	0.07	N	N	N	0.02	N	N	N
AISI 304	-	-	-	-	0.03	N	N	N
Titanium	0.02	N	N	-	+ ^f	N	N	-
Copper Coupled to Cast Iron	2.52	N	-	-	7.78	N	-	-

^a189°F, 0 ppb oxygen, Re = 7.16×10^4 , test duration 808.5 hours

^b189°F, 30 ppb oxygen, Re = 4.13×10^4 , test duration 543 hours

^cIncipient pitting

^dIncipient crevice corrosion

^ePits about one grain deep occurred in areas of maximum stress

^fWeight gain

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - Data not available

SOURCE: Ellis 1980_a

of carbon steel. Copper coupled to cast iron, however, had twice the uniform corrosion rate of carbon steel. The rates were 2.52 mpy in non-aerated fluid and 7.78 mpy in aerated fluid.

The corrosion test results indicate that the introduction of a low level (30 ppb) of dissolved oxygen has a pronounced effect on the corrosion rate of carbon steel in turbulent flow conditions. The uniform corrosion rate increased about fourfold when 30 ppb oxygen was introduced. The effect of a low level of oxygen on deoxidized copper was not as large; the uniform corrosion rate nearly doubled. There was little effect on Admiralty brass, AISI 316, or titanium.

The tests with copper coupled to cast iron show that copper is not protected by a galvanic couple to iron in these environments. In fact, coupling caused more than a twofold increase in uniform corrosion rate in nonaerated fluid and a fourfold increase in aerated fluid as compared to the rates for copper alone.

Pitting did not occur in any of the materials tested. However, localized roughening (too shallow to measure) occurred on carbon steel exposed to aerated fluid. This indicates possible incipient pitting.

The most severe crevice corrosion occurred with carbon steel. The rates were 13 mpy in nonaerated fluid and 50 mpy in aerated fluid. Incipient crevice corrosion was observed on deoxidized copper and admiralty brass in both fluid tests.

Stress corrosion cracking was not observed for any of the materials tested. However, pits about one grain deep occurred in maximum stress areas on the Admiralty brass coupons exposed to nonaerated fluid.

The corrosion rates of carbon steel measured in this test are consistent with rates estimated during failure analysis of components from the OIT system (Mitchell 1979d). The corrosion rates in this test were 1.05 to 4.04 mpy; estimated rates for two pieces of carbon steel pipe were 1.2 and 4.2 mpy. Estimated uniform corrosion rates for copper tubing in service at OIT were one to four mpy (Mitchell 1979d). The corrosion rates for copper measured in this test were 1.05 to 1.91 mpy.

Carbon steel exposed to essentially stagnant fluid during the OIT/INCO tests mentioned in the previous section had uniform corrosion rates three to four times lower than the rates measured in the PNL/Radian tests. Corrosion rates of copper are four to eight times higher in turbulent fluid ($Re = 41,300$ to $71,600$) than in stagnant oxygen-free fluid. For carbon steel and deoxidized copper, corrosion is in the active mode and is dependent on the mass transport of reducing species to the metal surface. This accounts for increased corrosion rates under turbulent conditions. AISI 316, however, is passivated; thus, its corrosion rate is not dependent

on mass transport. There is little difference between corrosion rates in stagnant fluid and corrosion rates in turbulent fluids.

4.16.3 Operating Experience

The geothermal heating system at a Klamath Falls apartment complex consists of a lineshaft down-hole centrifugal pump. It supplies fluid at 50 psig through a chlorinated polyvinyl chloride (CPVC) plastic piping system to the seventeen buildings (121 apartments) at approximately 125°F. The pressure is reduced to 27 psig at each building, and the fluid is distributed through copper tubing. Each individual apartment has a fan coil heater. It is a once-through system; the discharge fluid temperature is 108°F to 112°F. The spent geothermal fluid is discharged into the storm drains (Ellis 1980b).

The geothermal heating system at the Oregon Institute of Technology (OIT) consists of three wells approximately 1475 ft to 1800 ft in depth. The geothermal fluid is pumped by variable-speed 56 kW, motor-driven, submerged lineshaft pumps to a storage tank at atmospheric pressure. The 192°F fluid flows by gravity to the various campus buildings. It is used for space heating and domestic water heating. The useful heat is extracted either at a central location within a building or at individual room convectors, depending on the age and design of the buildings. The fluid is also used to heat a greenhouse and two ponds where prawns are raised. Spent geothermal fluid is discharged to the college storm drain system. The discharge temperature is approximately 90°F (Ellis 1980b).

The heating system of the hospital consists of a single well which supplies geothermal fluid at about 190°F to a holding tank on a demand basis. The incoming water is mixed with cooler, recirculated geothermal fluid to maintain a temperature of 150°F to 170°F. This water is circulated through a series of tube-and-shell heat exchangers where the usable heat is transferred to a secondary working fluid. For domestic water heating and space heating, the secondary fluid is treated water. Ethylene glycol is used as the secondary fluid in a pavement thawing system. After the geothermal fluid passes through the heat exchangers, some of it is discharged to the storm drains. The remainder is returned to the holding tank (Ellis 1980b).

In all of these systems, the materials are those used in typical fossil-fired hydronic heating systems. Buried supply pipe is usually made of carbon steel. Baseboard convectors or fan coils are conventional copper-tubed units with aluminum fins. The heat exchangers at the hospital are tube-and-shell units with carbon steel shells and tubesheets, and copper tubes.

4.16.3.1 Well Casing and Production Equipment

Typical wells range from eight to twelve inches in diameter and are cased with carbon steel pipe (usually AISI 1010). Well depths range from about 200 ft to 300 ft to a maximum of 1900 ft (Lund 1976). There have been few instances of well casing failure. The life of a one-fourth-inch thick well casing has been estimated to be at least 50 years at a uniform corrosion rate of five mpy (Lund 1976). Accelerated casing corrosion, without failure, has occurred when dissimilar metals (such as copper) have been placed in the well. In this case, galvanic corrosion of the casing has been observed (Lund 1976).

Downhole heat exchangers, or coils, are usually made with AISI 1010 carbon steel (black iron) pipe. Geothermal fluid enters the well through slots in the well casing and contacts the coil. Heat is extracted from the geothermal fluid using city water, ethylene glycol, or oil as a secondary fluid in the coil. Coils usually fail by corrosion at the waterline within five to twenty years. Corrosion tests and experience have shown that coil failure will occur five to ten times more rapidly at the waterline than at any other location. Useful operating life of the coil, typically 5 to 20 years, varies according to individual well chemistry, temperature, stray electric current effects, and construction materials.

Downhole pump corrosion has occurred in a manner similar to that of downhole heat exchangers. However, failures due only to corrosion have not occurred because the components are made of much thicker materials. A pump casing and shaft removed from service at the Medo-Bel Dairy in Klamath Falls were investigated for corrosion. The deposits scraped off the housing and shaft were corrosion products formed by the action of geothermal fluid on pump materials. Elemental analysis of the deposits showed iron and copper to be the major constituents. The deposit was determined by x-ray diffraction to be mainly magnetite particles coated with a copper-rich compound (Mitchell 1979a).

Failure of a downhole lineshaft pump from the hospital's heating system was also analyzed. (The pump supplies hot geothermal fluid from the well to the storage tank as needed; operation is intermittent.) Deposits in the pump bowl had prevented impeller rotation. Elemental analysis of the deposits (by energy-dispersive x-ray spectroscopy) and compound identification (by x-ray diffraction) showed that the corrosion product deposit from the pump bowl was identical to the deposit from the pump casing and shaft. It was determined that the pump bowl clogged because corrosion products, which exfoliated from the pump column, settled into it during idle periods (Mitchell 1979e).

4.16.3.2 Geothermal Fluid Piping

In Klamath Falls, both steel and copper piping are used to transport geothermal fluid from wells to its point of use. Carbon steel pipe is

normally used as buried supply pipe from well to building. Copper pipe is used for distribution piping inside buildings.

Until 1980, geothermal water was transported between the holding tank and the various buildings at OIT through buried carbon steel pipes. These pipes were insulated with preformed foamed glass and covered with a mastic. No protective coating had been applied between the pipe and the foamed glass. Maintenance history of the OIT system indicated that several supply lines had failed during the fourteen-year operating life of the system. All of the failures occurred in buried pipe. Failure analysis of some exposed pipe revealed that the mastic had lost integrity, especially near the pipe elbows. It was concluded that salt water from sidewalk deicing had penetrated the insulation of the buried pipe and caused failure by external corrosion (Ellis 1980b).

Another section of steel pipe at OIT carrying 192°F geothermal water failed after about fourteen years of service. The interior of the pipe had a deposit buildup one-sixteenth inch to one-fourth inch thick. The deposit was mainly magnetite and silica. The deposit was layered with a band of black iron oxide adherent to the pipe and coated with silica and clays (Mitchell 1979c). The internal surface was rough due to formation of corrosion tubercles. Beneath the tubercles, the pipe wall had been reduced by up to one-third of its original thickness. Failure was attributed to oxygen attack. Oxygen entered the system at the vented settling tank (Mitchell 1979d).

The steel pipe system at OIT has now been replaced by fiberglass-reinforced plastic (FRP) pipe. No data on the performance of this material is available.

At both the apartment complex and the college, the geothermal water is conducted through copper pipes inside the building. Failure analysis of a piece of 1.5-inch copper pipe which had been in service fourteen years was performed. The pipe supplied geothermal water to a heat exchanger at 120°F to 165°F. The pipe failed due to severe internal thinning of the copper adjacent to the steel fitting (Ellis 1980b). Corrosion rates on the order of one to six mpy have been calculated for copper components at Klamath Falls.

All copper components exposed to geothermal fluid were coated with a copper sulfide deposit. The black, loosely adherent scale was a product of copper corrosion by hydrogen sulfide. The scale was cracked both circumferentially and longitudinally. Deep grooves in the copper pipe resulting from crevice attack occurred wherever the scale had been cracked. The grooves (crevice corrosion) penetrated more than halfway through the pipe wall (Ellis 1980a).

Preferential solder corrosion and leakage have occurred at copper joints at the apartment complex and at OIT. A one-percent silver solder

used at the apartment complex failed after a 29-month exposure to 126°F geothermal fluid. In some cases, the solder was completely removed. At OIT, a 50/50 lead-and-tin solder was exposed to 192°F geothermal water for 14 years. The mode of failure was selective removal of one of the two phases of the solder (Mitchell 1979d). The solder corrosion was worse if the solder annulus was impinged by the fluid stream.

There have also been problems with valves at OIT. One brass valve, a pneumatically-actuated mixing valve, was removed from service because of valve stem seizure. Failure analysis showed that the seizure was caused by deposit buildup, and that the interior of the valve was coated with a layer of black, porous copper sulfide scale similar to that found in copper components. There were no indications of crevice corrosion of component internals or erosion of the valve seat.

A pneumatically-actuated plug valve was in service for thirteen years in variable temperature geothermal fluid before being removed. Failure occurred when the yellow brass plug detached from the austenitic stainless steel stem. Galvanic or crevice corrosion of the brass crimp, which secured the stem to the plug, caused the failure (Mitchell 1979d). A similar valve, in which the stem was threaded into the plug, gave satisfactory service with no plug/stem problems.

During cleaning of the hospital's heating system, the main circulating pump was disassembled. The vanes of the pump impeller were severely cracked in several places. Failure analysis determined that dealloying or dezincification had occurred in many areas of the impeller. The strength of the dezincified areas was so low that fracture occurred. In some areas of the impeller, the weak, spongy, porous copper phase extended completely through the impeller (Mitchell and Ellis 1979).

The pump impeller was fabricated from a cast silicon bronze (CA 875) containing 13 percent zinc. Copper alloys containing less than about 15 percent zinc are normally considered resistant to dezincification, but the Klamath Falls geothermal fluid contained sufficient dissolved carbon dioxide, and oxygen from in-leakage, to cause dezincification. The pattern of the impeller dezincification also indicated that fluid impingement on the material increased dezincification (Mitchell and Ellis 1979).

4.16.3.3 Heating Coils and Heat Exchangers

The primary construction materials of heating coils (fan-coils) and heat exchangers are copper and copper-based alloys (bronze and brass). Copper-tubed heating coils at OIT and the apartment complex have corroded like copper pipe. The rates are three to six mils per year (Ellis and Mitchell 1979). Because heat exchangers generally have thinner pipe walls, their components may fail before copper distribution pipe.

Ten fan-coils at the apartment complex failed during the fall of 1978. Failure occurred after fewer than 29 months of service. A failure

analysis was performed on a coil similar or identical to the other units in service at the apartment complex. It consisted of 24 straight runs of copper tubing formed into four parallel circuits by integral drawn U-bends at the return end of the coil. At the manifold end, tube runs were connected by separate U-bends which were inserted into the runs and held with a one percent silver solder. The nominal wall thickness was 16 mils. The design flow rate was two feet per second.

Failures occurred at the inlet manifold and at the return bends of the fan coil unit. Corrosion of soldered joints had allowed leakage at the manifold end of the coil. At the return end of the unit, the tubing was perforated and was leaking. The average wall thickness of the return bends in the most corroded areas was 2.5 mils. The wall thickness of the straight-run portions was reduced also; the average remaining wall thickness was 6.3 mils. From these measurements, corrosion rates of 5.4 mpy for bends and 3.9 mpy for straight sections were calculated. Based on these corrosion rates and past history of failures, leaks could be expected in 50 percent of the return bends within 31 to 39 months of service and in 50 percent of straight-run tubes within 37 to 70 months of service (Ellis and Mitchell 1979).

The interior surface of the fan-coil tubing was covered with a black copper sulfide scale. The scale was thickest (50 mils) where the wall was most severely corroded and thinnest (12 mils) where corrosion was least severe. The scale was fragile and non-adherent. No carbonates, sulfates, or copper oxides were detected in the scale (Ellis and Mitchell 1979).

A large fan-coil from OIT was also examined. The unit consisted of 36 parallel, aluminum-finned copper tubes rolled into cast iron manifolds. Failure occurred at the junction of copper and cast iron. This indicated galvanic corrosion. No localized corrosion of the tube-sheet crevice was observed (Mitchell 1979d).

A plate-type heat exchanger was tested at OIT as part of a joint study with Radian Corporation, Pacific Northwest Laboratories, A.P.V. Company, Inc. (APV), and OIT. A Junior Paraflow Plate Heat Exchanger, Specification No. 1, was provided by APV for this purpose.

The plates measured 2.75 inches by 22.75 inches and were 0.028 inches thick. They were corrugated in a herringbone (chevron) pattern, and each plate had a heat transfer area of 0.27 square feet. The plates had nitrile rubber gaskets and were secured with six tie bars.

For this test, the plates were divided into three stages in series. The three stages were connected with AISI 316 connectors. Each stage had 21 plates forming countercurrent channels for geothermal and secondary water. The high and low temperature sections had AISI 316 plates, and the intermediate temperature section had titanium plates.

During the test, the plate heat exchanger was supplied with 16,000 lbm/hr of 192°F geothermal fluid. Some plates were exposed for 3600 hours; others were exposed for 6500 hours. During the first period, the OIT supply wells were shut in for 700 to 1500 hours. During shut-in, the heat exchanger was kept in a wet lay-up condition.

Examination of the plates revealed no evidence of uniform corrosion, pitting, stress corrosion cracking, or crevice attack under the gaskets. The appearance of the 3600-hour plates was identical to that of the 6500-hour plates (Ellis and Anliker 1980).

Deposits were observed on both the geothermal side and secondary fluid side of the plates. The translucent olive-green film on the geothermal water side was less than two mils thick and consisted mainly of iron. The secondary fluid side of the plates was uniformly covered with a reddish-brown film less than 1.5 mils thick. The major constituent was iron; silicon, calcium, and manganese were present in large amounts. It was concluded that deposits on both surfaces resulted from deposition of minerals from the water and/or carry-over from the piping upstream of the plate heat exchanger (Ellis and Anliker 1980).

In the hospital's heat exchangers, deposits were removed both before and after chemical cleaning for analysis by Radian Corporation. The main constituents of the deposits were minerals such as calcium sulfate from the geothermal fluid, and iron oxide. The iron oxide is indicative of oxygen-related corrosion of steel components in the geothermal fluid supply system (Mitchell 1979e).

A copper tube-in-tube heat exchanger for a heat pump at a private residence was analyzed for failure. The heat exchanger utilized 79°F well water in the inner tube and freon in the annulus. Calculated water velocity was 14.8 to 15.6 feet per second. Three replacement units were required within a five-year period. The inner surface of the inner tube was covered with a thin layer of greenish-white scale, determined to be mainly cupric oxide. The attack formed the "horse shoe" corrosion pattern typical of erosion-corrosion. The critical velocity, above which erosion-corrosion of copper occurs, is 4.3 fps. Failure resulted from operation of the heat exchanger at water velocities far above the critical erosion-corrosion velocity for copper (Ellis 1980c).

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4.17 MADISON AQUIFER

The Madison Aquifer is the largest identified geothermal resource in area in the United States. It underlies the northwest half of South Dakota and extends into North Dakota, Wyoming, and Montana. The formation has been extensively studied in South Dakota (Gries 1977). Section 4.17 pertains to the portion of the Madison Aquifer in that state.

The depth of the aquifer varies from less than 1000 feet near the Black Hills and in western South Dakota to more than 7000 feet in far northwest South Dakota. Figure 4.17-1 shows the Madison Aquifer in South Dakota. Shaded areas indicate temperature at the top of the aquifer. Actual production temperatures are normally 3° to 5°F higher (Gries 1977). In general, the temperature varies with depth, according to the normal geothermal gradient in the earth's crust. An exception to this is the "island" of high temperature near the eastern edge of the aquifer (see Figure 4.17-1).

Small-scale geothermal space heating systems have been in operation in the town of Midland and Philip for at least fifteen years. The Madison Aquifer has been used as a domestic water source since the 1930's.

4.17.1 Fluid Chemistry

The Madison geothermal waters are derived from a dolomite (calcium carbonate) formation. The waters are neutral sulfate or neutral bicarbonate waters containing between 1 and 260 ppm chloride. Total dissolved solids (TDS) range from less than 500 ppm near the Black Hills to more than 4000 ppm in northwest South Dakota. Figure 4.17-1 presents TDS concentration gradients in the Madison aquifer. The water chemistry from eighteen wells with reported temperatures greater than 120°F is presented in Table 4.17-1. This table also gives the range of fluid composition for which corrosion results are available. The Madison geothermal waters contain nitrogen and carbon dioxide as dissolved gases (Gries 1977). The concentrations for two wells are presented in Table 4.17-2.

The water in the reservoir (dolomite) formation is saturated with calcium carbonate. The waters produced are slightly supersaturated with calcium carbonate. The calcium carbonate saturation pH (pHs) is calculated by the Loewenthal and Marais method and ranges from 6.0 to 7.3 (Loewenthal and Marais 1976). The measured pH varies from 6.5 to 7.7. Calcium carbonate scaling is not a problem unless the fluid is exposed to air (Gries 1977). Carbon dioxide loss would then cause precipitation of calcium carbonate.

FIGURE 4.17-1. LOCATION OF PORTION OF MADISON AQUIFER IN SOUTH DAKOTA

TABLE 4.17-1. FLUID CHEMISTRY OF THE MADISON AQUIFIER

COMPONENTS		Range of Wells With Temperature Greater Than 120°F	Range of Wells Used for Materials Tests
<u>Key Species:</u>			
pH		6.5 - 7.7	6.9 - 7.7
		<u>ppm</u>	<u>ppm</u>
Chloride	(Cl ⁻)	1 - 257	21 - 255
Sulfate	(SO ₄ ⁻²)	180 - 1622	180 - 1087
Bicarbonate	(HCO ₃ ⁻)	121 - 238	126 - 238
Carbonate	(CO ₃ ⁻²)	-	-
Hydrogen Sulfide	(H ₂ S)	-	-
Ammonia	(NH ₃)	-	-
<u>Other Species:</u>			
TDS		836 - 2710	880 - 2066
Silica	(SiO ₂)	21 - 42	28 - 42
Calcium	(Ca)	73 - 37	108 - 381

-: No Data Available

Source: Gries 1977

TABLE 4.17-2. RESULTS OF GAS ANALYSIS FROM TWO MADISON WELLS

COMPONENT	CONCENTRATION (ppm)	
	Philip City Well Water	Midland City Well Water
Carbon Dioxide (CO ₂)	40	40
Hydrogen Sulfide (H ₂ S)	-	-
Oxygen (O ₂)	0.012	<0.013
Balance	15	26

-: Data Not Available

Source: Carda 1979

4.17.2 Corrosion Tests

Corrosion tests or experience are available from four sites in South Dakota. Materials tests have been performed at the towns of Edgemont and Philip, as well as at the Hilltop Diamond Ring Ranch (formerly the Bar-N). Operational experience is available from Philip and Midland. Corrosion test results and operating experience at each site will be discussed separately in the following sections.

4.17.2.1 Edgemont

The rural community of Edgemont, located near the Black Hills in western South Dakota, has used Madison aquifer water for domestic water supply since the 1930's. Wells 2950 to 3450 feet deep tap water at 125° to 140°F.

Methods and Conditions

Weight-loss and stress corrosion specimens were exposed to low velocity (approximately 0.2 ft/sec) water from Edgemont City Well No. 2 for 45 days. Fluid chemistry from this well is presented in Table 4.17-3. The coupons were evaluated by the South Dakota School of Mines and Technology (SDSMT) and the Ampco Metal Division of Ampco-Pittsburgh Corporation (AMPCO).

TABLE 4.17-3. CHEMISTRY OF GEOTHERMAL WATER FROM WELL EDMONT
CITY NO. 2

COMPONENT		CONCENTRATION
<u>Key Species:</u>		
pH		7.6
		<u>ppm</u>
Chloride	(Cl ⁻)	225
Sulfate	(SO ₄ ⁻²)	315
Bicarbonate	(HCO ₃ ⁻)	198
Carbonate	(CO ₃ ⁻²)	-
Hydrogen Sulfide	(H ₂ S)	^a
Ammonia	(NH ₃)	-
<u>Other Species:</u>		
TDS		1109
Silica	(SiO ₂)	28
Sodium	(Na ⁺)	186
Calcium	(Ca ⁺²)	123

^aFaint odor

-: No data available

Source: Gries 1977

Results

The results of the 45-day material test are presented in Table 4.17-4. In general, the uniform corrosion rates of all materials except carbon steel, aluminum 3003, and Monel 400 were less than 1 mpy. All alloys were covered with a thin, brown tarnish at the end of the exposure period. No copper sulfide scale was detected, and no stress corrosion cracking of any alloy observed. Individual materials are discussed below.

Carbon steel corroded at 15.2 mpy. This corrosion rate indicates that dissolved oxygen was present in the test environment.

AISI 304 stainless steel corroded at 0.014 mpy, while AISI 316 corroded at 0.018 mpy. Both alloys had pits visible at low (10X) magnification. The depth of attack was not reported. Slight (unquantified) crevice corrosion was also observed.

Deoxidized copper corroded at 0.24 mpy with slight (visible at 10X) pitting and crevice corrosion.

The corrosion rate of Admiralty Brass (CA443) was almost twice the corrosion rate of copper. It showed similar pitting and crevice corrosion.

7Al-3.5Fe bronze (CA613) corroded at 0.10 mpy, while cast 9Al-5Ni-4Fe bronze (CA958) corroded at 0.13 mpy. Annealing the CA958 caused a threefold increase in corrosion rate, while welding had little effect. All of these alloys had pits visible at 10X magnification, and slight crevice corrosion.

The uniform corrosion rate of 70-30 cupronickel (CA715) was only 0.45 mpy, but the sample was perforated, and Monel 400 corroded at 1.2 mpy and was severely (not qualified) pitted.

Titanium corroded at 0.012 mpy with no pitting or crevice corrosion. Aluminum 3003 was reported as destroyed.

Operating Experience

No operating experience data are available from Edgemont geothermal facilities. It is reported that local plumbers avoid the use of copper pipe in domestic systems (which use cooled geothermal water).

4.17.2.2 Philip

The community of Philip is located in central South Dakota. The 4000-foot deep Philip city well taps 157°F water for the local water supply.

TABLE 4.17-4. CORROSION RESULTS AT EDMONT, SOUTH DAKOTA

MATERIAL TESTED	SPECIFICATION	LOW VELOCITY FLUID			
		Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>					
Carbon	AISI 1020	15.2	-	-	-
<u>Stainless Steels</u>					
18Cr-8Ni	Type 304	0.014	x ^a	x ^e	N
18Cr-12Ni-2.5Mo	Type 316	0.018	x ^a	x ^e	N
<u>Copper Alloys</u>					
Deoxidized Copper		0.24	x ^a	x ^e	N
Admiralty Brass (As)	CA443	0.43	x ^a	x ^e	N
7Al-3.5Fe Bronze	CA613	0.10	x ^a	x ^e	N
7Al-3.5Fe Bronze (welded)		-	-	-	
7Al-2.5Fe-1Mn Bronze	CA614	-	-	-	
70-30 cupronickel	CA715	0.45	x ^b	x ^e	N
9Al-5Ni-4Fe Bronze (cast)	CA958	0.13	x ^a	x ^e	N
9Al-5Ni-4Fe Bronze (annealed)		0.36	x ^a	x ^e	N
9Al-5Ni-4Fe Bronze (welded)		0.14	x ^a	x ^e	N
<u>Other Alloys</u>					
Monel 400		1.19	x ^c	-	N
Titanium		0.012	N	-	N
Aluminum	3003	x ^d	-	-	-

^aPits visible at 10X^bPerforated^cSevere (not quantified)^dCoupon destroyed^eDetected - reported as "slight"

Source: Howard and Carda 1979

KEY TO TABLE:

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - No data available

Methods and Conditions

Weight-loss coupon tests were performed at Philip by the SDSMT. Coupons were exposed to water at about 0.2 ft/sec from the Philip city well for 145 days. The coupons were evaluated by SDSMT and AMPCO.

The composition of the water is presented in Table 4.17-5. This water contains about 30 ppb hydrogen sulfide. The water is also contaminated with traces of oxygen, though the exact amount is not known (Howard 1979).

Results

Results of the Philip test are presented in Table 4.17-6. All materials were covered with loose copper sulfide scale. No dealloying of copper alloys was observed. The performance of individual alloys is discussed below.

Carbon steel corroded at 4.72 mpy, indicating oxygen contamination. The surface was roughened.

AISI 304 and AISI 316 stainless steels corroded at 0.019 and 0.025 mpy, respectively. Neither showed signs of pitting. Deoxidized copper and Admiralty Brass (CA443) corroded at essentially the same rate (approximately 0.13 mpy). No pitting was reported.

The uniform corrosion rate of 7Al-3.5Fe bronze (CA613) was 0.24 mpy. Welding doubled the corrosion rate. No pitting was reported. 9Al-5Ni-4Fe bronze corroded at about twice the rate of CA613. Welding had little effect.

70-30 cupronickel (CA715) corroded at 0.32 mpy without detected pitting. Monel 400 corroded at 0.40 mpy without pitting.

Aluminum 3003 corroded at 4.43 mpy. Pitting (unquantified) occurred.

Operating Experience

The water treatment plant at Philip is heated by two forced-air fan coils and a baseboard convection unit. The tubing is copper with soft soldered joints. The fan coils fail because of uniform corrosion of the small tubes. The fan coils have a service life of 5 to 11 years, while the baseboard convactor has lasted eleven years. All interior surfaces were covered by nonadherent copper sulfide scale. The corrosion rates of tubing in the fan coils were 1.9 mpy at five years and 1.6 mpy at eleven years. The baseboard convactor tubing corroded at 1.6 mpy (Gries 1977). These corrosion rates are twelve to fifteen times greater than those measured in

TABLE 4.17-5. CHEMISTRY OF GEOTHERMAL WATER FROM WELL PHILIP
CITY NO. 1

COMPONENT		CONCENTRATION
<u>Key Species:</u>		
pH		7.2
		<u>ppm</u>
Chloride	(Cl ⁻)	21
Sulfate	(SO ₄ ⁻²)	633
Bicarbonate	(HCO ₃ ⁻)	160
Carbonate	(CO ₃ ⁻²)	-
Hydrogen Sulfide	(H ₂ S)	0.03
Ammonia	(NH ₃)	-
Oxygen	(O ₂)	<1 ^a
<u>Other Species:</u>		
TDS		1172
Silica	(SiO ₂)	34
Sodium	(Na ⁺)	18
Calcium	(Ca ⁺²)	221

^aEstimated

—: No data available

Source: Gries 1977

TABLE 4.17-6. CORROSION TEST RESULTS AT PHILIP, SD

MATERIAL TESTED ^a	SPECIFICATION	LOW VELOCITY FLUID			
		Uniform Corrosion (mpy)	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>					
Carbon	AISI 1020	4.72	x ^b	-	-
<u>Stainless Steels</u>					
18Cr-8Ni	Type 304	0.019	N	-	-
18Cr-12Ni-2.5Mo	Type 316	0.025	N	-	-
<u>Copper Alloys</u>					
Deoxidized Copper		0.13	N	-	-
Admiralty Brass (As)	CA443	0.12	N	-	-
7Al-3.5Fe Bronze	CA613	0.24	N	-	-
7Al-3.5Fe Bronze (welded)		0.43	N	-	-
7Al-2.5Fe-1Mn Bronze	CA614	-	-	-	-
70-30 cupronickel	CA715	0.32	N	-	-
9Al-5Ni-4Fe Bronze (cast)	CA958	0.51	N	-	-
9Al-5Ni-4Fe Bronze (annealed)		-	-	-	-
9Al-5Ni-4Fe Bronze (welded)		0.60	N	-	-
<u>Other Alloys</u>					
Monel 400		0.40	-	-	-
Titanium		-	-	-	-
Aluminum	3003	4.43	x ^c	-	-

^a145 day exposure^bRough surface^cShallow pitting (visible at 10X)

SOURCE: Gries 1977

KEY TO TABLE:

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected

- - No data available

the coupon corrosion tests. Similar differences in corrosion rates between copper fan coil tubes and coupons were observed at Klamath Falls (Section 4.16).

Geothermal water is supplied at Philip through two-inch copper pipe which has considerably greater wall thickness than the fan coil tubes. No failure of this supply piping has occurred in seventeen years of service. Destructive analysis of a portion of pipe disclosed no marked thinning, even in elbows. No pitting was observed. The interior surface was coated with copper sulfide scale (Gries 1977).

A bronze (unspecified grade) valve body and gate were also found to be in good condition after twelve years (Gries 1977).

4.17.2.3 Hilltop Diamond Ring Ranch

The Hilltop Diamond Ring Ranch (formerly the Bar-N) is located near Philip. The 4100-foot well produces 250 gallons per minute of water at 145°F. This water has been used for stock watering for some time. The geothermal resource at Hilltop Diamond Ring Ranch is being developed for space heating of employee quarters, work spaces, and animal sheds. The cooled water will supply water for stock. Materials tests in support of this effort have been performed.

Methods and Conditions

Coupons of carbon steel, copper alloys, aluminum 3003, Monel 400, and titanium were exposed to 0.2 ft/sec flow for periods up to 414 days. After 91 days, the coupons were evaluated for weight loss corrosion by SDSMT and AMPCO (Howard and Carda 1979). Pitting and crevice corrosion were evaluated after 414 days (Howard et al. 1978). Stress corrosion tests were performed by SDSMT. Specimens were exposed for 180 days.

The water at Hilltop Diamond Ring Ranch contains 185 ppm chloride and 1087 ppm sulfate. Total dissolved solids (TDS) are approximately 2000 ppm. The composition of this water is given in Table 4.17-7. The fluid contains 200 ppb hydrogen sulfide and some dissolved oxygen contamination. The amount of oxygen is not known but is probably less than 1 ppm (Howard et al. 1978).

Results

Test results are presented in Table 4.17-8. All coupons were covered with copper sulfide scale (Gries 1977). No stress corrosion of any material was reported (Howard and Carda 1979).

Carbon steel (AISI 1020) corroded at 15.8 mpy. No pitting or crevice corrosion results were reported.

TABLE 4.17-7. CHEMISTRY OF GEOTHERMAL WATER FROM HILLTOP DIAMOND
RING RANCH WELL

COMPONENTS		CONCENTRATION
<u>Key Species:</u>		
pH		6.9
		<u>ppm</u>
Chloride	(Cl ⁻)	185
Sulfate	(SO ₄ ⁻²)	1087
Bicarbonate	(HCO ₃ ⁻)	126
Carbonate	(CO ₃ ⁻²)	-
Hydrogen Sulfide	(H ₂ S)	0.20
Ammonia	(NH ₃)	-
<u>Other Species:</u>		
TDS		2066
Silica	(SiO ₂)	42
Sodium	(Na ⁺)	85
Calcium	(Ca ⁺²)	381

-: No data available

Source: Gries 1977

AISI 304 corroded at 0.16 mpy with shallow (not quantified) pitting and incipient crevice corrosion. AISI 316 corroded at 0.05 mpy with no pitting, but with incipient crevice attack.

Deoxidized copper corroded at 4.1 mpy without localized attack, while Admiralty Brass (CA443) corroded at 0.74 mpy, also without localized

TABLE 4.17-8. CORROSION RESULTS AT DIAMOND RING (BAR-N) RANCH

MATERIAL TESTED	SPECIFICATION	LOW VELOCITY FLUID			
		Uniform Corrosion (mpy) ^{a,b}	Pitting ^b	Crevice Corrosion ^b	SCC ^c
<u>Low Alloy Iron Base</u>					
Carbon	AISI 1020	15.8	-	-	-
<u>Stainless Steels</u>					
18Cr-8Ni	Type 304	0.16	x ^d	x ^f	N
18Cr-12Ni-2.5Mo	Type 316	0.05	N	x ^f	N
<u>Copper Alloys</u>					
Deoxidized Copper		4.1	N	N	N
Admiralty Brass (As)	CA443	0.74	N	N	N
7Al-3.5Fe Bronze	CA613	1.2	N	N	N
7Al-3.5Fe Bronze (welded)		0.76	N	N	N
7Al-3.5Fe-1Mn Bronze	CA614	0.75	-	-	-
70-30 cupronickel	CA715	1.46	N	N	N
9Al-5Ni-4Fe Bronze (cast)	CA958	0.62	x ^e	N	N
9Al-5Ni-4Fe Bronze (annealed)		0.58	x ^e	N	N
9Al-5Ni-4Fe Bronze (welded)		0.52	x ^e	N	N
<u>Other Alloys</u>					
Monel 400		0.75	x ^e	x ^f	N
Titanium		N	N	N	N
Aluminum	3003	x ^g	-	-	-

^a 91 day exposure (Howard and Carda 1979)KEY TO TABLE:^b 414 day exposure (Howard et al. 1978)

N - Indicated form of corrosion not detected

^c 180 day exposure (Howard and Carda 1979)

X - Indicated form of corrosion detected

^d Shallow pits

- - No data available

^e Not quantified^f Incipient^g Coupon destroyed

SOURCE: Gries 1977

attack. Monel 400 corroded at 0.75 mpy with pitting (of unquantified depth) and incipient crevice corrosion.

7Al-3.5Fe bronze (CA613) corroded at 1.2 mpy. Welding reduced the corrosion rate to 0.76 mpy. No localized attack of either plain or welded coupons was reported. 7Al-2.5Fe-1Mn bronze (CA614) gave similar results (uniform corrosion of 0.75 mpy).

9Al-5Ni-4Fe cast bronze (CA958) corroded at 0.62 mpy. Annealing or welding had very little effect. The material showed large shallow (unquantified) pits and no crevice corrosion.

Titanium showed no detectable corrosion, either uniform or localized. On the other extreme, Aluminum 3003 was reported as destroyed after 91 days.

4.17.2.4 Midland

No materials tests have been performed at Midland, a rural community near Philip. Independent School District 114 heats its two largest buildings with recirculating secondary water heated by geothermal water in primary (isolation) heat exchangers. The isolation heat exchangers (one for each building) are conventional shell-and-tube units with carbon steel shells and copper tubes (wall thickness not reported). Madison geothermal water flows on the tube side.

It is reported that the steel shell in the older building was replaced once in thirteen years, while the tubes were replaced twice. Failure was due to corrosion rather than scaling. The second isolation heat exchanger was installed in 1972 and has performed without failure (Gries 1977).

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4.18 RAFT RIVER, IDAHO

Wells 4900 to 5900 feet deep tap 298°F geothermal water at the Raft River KGRA located in Cassia County, Idaho (see Figure 4.18-1). The unpumped flow rates of the wells, when flashing does not occur, varies from about 278,000 lb/hr to 370,000 lb/hr (Cosner and Apps 1978).

The Raft River is the geothermal resource used in an effort to develop direct binary cycle technology for use in the 300°F temperature range. A 5MW, isobutane, direct binary pilot plant is under construction. Experiments with various direct utilization concepts are also under way (Kunze 1978). An integrated power generation and process industry facility is visualized.

4.18.1 Fluid Chemistry

The Raft River geothermal fluid is a neutral chloride water with total dissolved solids of 1000 to 2000 ppm. Noncondensable gases compose about 1.5 percent (volume) of the total flow. Table 4.18-1 gives the composition of water from three wells at Raft River; Table 4.18-2 gives composition of noncondensable gases. The resource is unusual because of its very low (less than 100 ppb) hydrogen sulfide concentration. The reservoir water is presumed to be oxygen-free.

4.18.2 Corrosion Tests

The rates of uniform and crevice corrosion and pitting have been studied at Raft River. The results are summarized in Screening Table 4.18-3. Another series of tests investigated galvanic and crevice corrosion of potential heat exchanger materials.

4.18.2.1 Coupon Tests

Methods

Field tests at Raft River evaluated materials for binary cycle heat exchanger, valves, pumps, and other equipment. Coupons mounted on a test rack with TFE Teflon insulators and washers were exposed to wellhead fluid from well RRGE 1 at 271°F.

A planned interval test procedure was employed in which the duration of coupon exposure was varied up to a maximum of 109 days. The results of planned interval tests indicate whether corrosion rates increase or decrease with time and whether the corrosiveness of the fluid changes during the test period.

After exposure, the coupons were visually inspected, cleaned, and weighed. The weight losses measured after 109 days of exposure were used

FIGURE 4.18-1. LOCATION OF RAFT RIVER GEOTHERMAL RESOURCE

TABLE 4.18-1. COMPOSITION OF WELLHEAD FLUID FROM THREE WELLS IN THE
RAFT RIVER, IDAHO, KGRA

FLUID COMPONENT	CONCENTRATION		
	Well RRGE 1	Well RRGE 2	Well RRGE 3
<u>Key Species (ppm):</u>			
pH	7.23	7.46	6.70
Chloride (Cl ⁻)	776	708	2170
Bicarbonate (HCO ₃ ⁻)	63.9	41.3	44.4
Sulfate (SO ₄ ²⁻)	60.2	54.1	53.3
Hydrogen sulfide (H ₂ S)	0.1	0.256	—
Ammonia (NH ₃)	—	—	—
<u>Other Components (ppm):</u>			
Silica (SiO ₂)	91	170	114
Sodium (Na)	445	416	1185
Potassium (K)	31.3	33.4	97.2
Lithium (Li)	1.5	1.2	3.1
Magnesium (Mg)	2.4	0.6	0.6
Calcium (Ca)	53.5	35.3	193
Strontium (Sr)	1.6	1.0	6.7
Fluorine (F)	6.3	8.3	4.6
Bromine (Br)	1.5	1.5	1.5
Iodine (I)	0.04	0.03	—
Total Dissolved Solids	1215	2000	

—: Data not available

Source: Miller 1977

TABLE 4.18-2. COMPOSITION OF NONCONDENSABLE GAS FROM WELLS AT RAFT RIVER

COMPONENT		% (VOL) OF TOTAL FLOW	% (VOL) IN NONCONDENSABLE GAS FRACTION
Carbon dioxide	(CO ₂)	0.115	7.2
Hydrogen sulfide	(H ₂ S)	0.00035	0.022
Ammonia	(NH ₃)	—	—
Nitrogen	(N ₂)	1.44	90.16
Argon	(Ar)	0.030	1.89
Hydrogen	(H ₂)	0.0024	0.148
Helium	(He)	0.00078	0.049
Methane	(CH ₄)	0.0059	0.369

—: Data not available

Source: Cosner and App: 1978

to calculate uniform corrosion rates. Coupons were examined with a monocular metallurgical microscope in order to measure depths of pits and crevices. Pit and crevice depths were measured to the nearest +1 μm (Miller 1977). Maximum pit or crevice depths were used to calculate penetration rates.

Results and Discussions

The planned interval tests indicated that corrosion rates decrease with time. Results are presented in Table 4.18-4. The behavior of various alloys is discussed below.

Cast Iron, Carbon Steel, and Low Alloy Steels

The low alloy steels showed uniform corrosion (less than 2 mpy) as well as pitting (up to 44 mpy) and crevice attack (up to 37 mpy). Carbon steels and gray cast iron were pitted more severely than the low alloy steels, as shown in Table 4.18-4.

TABLE 4.18-3. RAFT RIVER CORROSION SCREENING RESULTS FOR WELLHEAD FLUID

MATERIAL TESTED	NONAERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>				
Gray Cast Iron (ASTM A48)	B	X	X	-
AISI 1018	B	X	X	-
Low Carbon Steel Plate (ASTM A515)	B	X	X	-
AISI 4140	A	X	X	-
Cor-Ten (ASTM A242)	B	X	X	-
9Cr Steel (ASTM A182 Gr.F9)	A	X	X	-
AISI Type 304	A	X	X	-
AISI Type 316	A	X	X	-
AISI Type 410	A	X	X	-
AISI Type 440A	A	X	X	-
Allegheny-Ludlum 216	A	X	X	-
Allegheny-Ludlum 6X	A	N	N	-
Allegheny-Ludlum 29-4	A	N	-	-
Allegheny-Ludlum 29-4-2	A	N	N	-
<u>Nickel Base</u>				
Monel 400	D	-	-	-
Inconel 625	A	N	N	-
Hastelloy G	A	X	N	-
<u>Titanium Base</u>				
Titanium (ASTM B265 Gr2)	A	N	N	-
<u>Aluminum Base</u>				
1100	D	X	X	-
5052	D	X	X	-
6061	D	X	N	-
<u>Copper Base</u>				
Ampco 8 (7Al bronze)	B	N	X	-
Ampco 12 (9Al bronze)	B	X	X	-
Ampco 483 (9Al - 4.5Ni bronze)	B	X	X	-
Muntz Metal (61Cu - 39Zn)	C	X	X	-
90-10 Cupronickel	D	N	X	-
70-30 Cupronickel	D	N	X	-
<u>Cobalt Base</u>				
Haynes 6B	A	N	N	-

KEY TO TABLE

- A - uniform corrosion rate ≤ 1.0 mpy
- B - uniform corrosion rate > 1.0 mpy but ≤ 10 mpy
- C - uniform corrosion rate > 10 mpy but < 50 mpy
- D - uniform corrosion rate > 50 mpy
- N - indicated form of corrosion not detected
- X - indicated form of corrosion detected
- - Data not available

Source: Miller 1977.

TABLE 4.18-4. RATES OF UNIFORM, PITTING, AND CREVICE CORROSION FOR METALS EXPOSED TO RAFT RIVER WELLHEAD FLUID

MATERIAL TESTED	CORROSION RATE IN NONAERATED FLUID ^a				COMMENTS
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d (mpy)	SCC ^e	
<u>Iron Base</u>					
Gray Cast Iron (ASTM A48)	1.6	7.9	13.2	-	^a Fluid from RRGE 1 at 272°F.
AISI 1018	1.8	43.5 ^f	33.6	-	^b Based on weight loss data after 109 day exposure unless otherwise indicated in comment column.
Low Carbon Steel Plate (ASTM A315)	1.9	33.1	36.9	-	^c Penetration rate calculated from maximum pit depth (Measured to ±1 μm).
AISI 4140	0.83	32.9 ^g	14.7	-	^d Penetration rate calculated from maximum crevice depth (measured ±1 μm).
Cor-Ten (ASTM A242)	1.1	7.5 ^h	13.2	-	^e Not differentiated as to mechanism.
9 Cr Steel (ASTM A182 Gr.F9)	0.39	17.4 ⁱ	X ^j	-	^f General broad shallow pitting under scale.
AISI Type 304	0.02	30.3 ^k	X ^l	-	^g Numerous pits of varying depth and breadth.
AISI Type 316	0.11	8.7 ^m	X ⁿ	-	^h Numerous small pits.
AISI Type 410	0.22	39.5 ^o	41.0 ^p	-	ⁱ Deep pits.
AISI Type 440A	0.28	76.5 ^q	100	-	^j "Deep" crevice corrosion-no numerical data given.
Allegheny-Ludlum 21c	0.38	47.9	X ^r	-	^k Numerous pits.
Allegheny-Ludlum 6X	0.0035	N	N	-	^l Crevice corrosion observed but not quantified.
Allegheny-Ludlum 29-4	0.0037	N	X ^s	-	^m Significantly less pitting than AISI Type 304.
Allegheny-Ludlum 29-4-2	0.0035	N	N	-	ⁿ "Some" crevice corrosion-not quantified.
<u>Nickel Base</u>					
Monel 400	79.7 ^t	-	-	-	^o Numerous narrow deep pits.
Inconel 625	N ^u	N	N	-	^p Severe crevice corrosion.
Hastelloy G	0.0035	X ^v	N	-	^q Scattered deep pits extending in direction of machining marks.
<u>Titanium Base</u>					
Titanium (ASTM B265 Gr.2)	0.0063	N	N	-	^r Pit under edge of washer could be crevice corrosion.
<u>Aluminum Base</u>					
1100	v	X	X	-	^s Minor evidence of crevice corrosion at 109 days.
5052	v	X	X	-	^t Exposure was for 2 weeks (preliminary test).
6061	v	X	N	-	^u No evidence of corrosion was found.
<u>Copper Base</u>					
Ampco 8 (7Al bronze)	3.9	N	N ^x	-	^v Few small scattered pits-no depth given.
Ampco 12 (9Al bronze)	7.5	7.5	7.9 ^x	-	^w Exposure for 11 weeks. All alloys were severely corroded. Some coupons showed 25% weight loss. Severe erosion.
Ampco 483 (9Al-4.5Ni bronze)	9.8	122	9.3 ^x	-	^x Dealloying under washer.
Muntz Metal (61 Cu - 39 Zn)	20 ^t	X ^y	X ^z	-	^y Small pits with dealloying into pits.
90-10 Cupronickel	275 ^t	N	X ^z	-	^z "Grooving" around washer.
70-30 Cupronickel	164 ^t	N	X ^z	-	
<u>Cobalt Base</u>					
Haynes 6B	0.017	N	N	-	

KEY TO TABLE

- N - indicated form of corrosion not detected.
- X - indicated form of corrosion detected.
- - no data reported.

Source: Miller 1977

Stainless Steels

AISI Type 410 and 440 steels showed the most catastrophic attack. The weight loss of these alloys was primarily due to severe (greater than 100 mpy) pitting in the area of the beveled edge of the TFE washer, as well as the nonoccluded areas, where pitting was about 77 mpy. These results lead to the conclusion that these and similar alloys should not be used in the hot geothermal fluid under conditions where crevices can be generated. Such applications include pump shafts where seals and bearings could provide the mechanical condition leading to crevice corrosion. These alloys are martensitic; other high chromium martensitic stainless steels have shown great susceptibility to sulfide stress cracking (SSC). SSC of this class of alloys is discussed in Appendix A.

Two austenitic stainless steels were tested. The depth of pitting and of crevice corrosion of AISI 304 was similar to the attack on AISI 410 and 440; however, the pits were not as numerous. Though localized attack was severe (pit penetration rate approximately 30 mpy), this material may be usable in some applications. AISI 316 was also pitted (penetration rate 8.7 mpy), but to a much lesser extent than AISI 304. On the basis of these data, AISI 316 would be acceptable in many applications. Both of these alloys are susceptible to stress corrosion cracking (SCC) in dilute chloride solutions as discussed in Appendix A.

Precipitation-hardening stainless steels such as 17-4PH are martensitic modifications of the austenitic stainless steels. In these alloys, the nickel content is lower, and elements such as aluminum, copper, molybdenum, and niobium are added to generate the second phase that results in hardening.

These materials are similar to AISI 304 stainless steel in regard to corrosion resistance in many environments (Miller 1977). Because the 17-4PH material is used in valve stem applications, careful testing and evaluation should precede its use at Raft River.

The super stainless steels, Allegheny-Ludlum Alloys 216 (20Cr-24Ni-2.5Mo), 29-4 (29Cr-4Mo), and 29-4-2 (29Cr-4Mo-2Ni), were resistant to uniform and local corrosion. The alloy 216 did show some pitting (47.9 mpy) near the TFE washer. The SCC resistance of these alloys is high. Nickel-free 29-4 is more resistant than nickel-containing alloys. All these alloys will resist cracking in boiling 20 percent sodium chloride.

Nickel-Based Alloys

Inconel 625 was very resistant. No uniform or local corrosion was detected after 109 days' exposure. Hastelloy G was also resistant to

uniform corrosion, but a few small pits (depths not quantified) were observed. Monel 400 is a copper-bearing nickel alloy, and like all the nickel-bearing copper alloys in this study, it was severely attacked. The uniform corrosion rate was 80 mpy.

Copper-Based Alloys

The nickel-free copper alloys, Ampco 8 (7Al-bronze), Ampco 12 (9Al-bronze), and Muntz Metal, were all fairly resistant, as shown in Table 4.18-4. Ampco 8 performed best. The nickel-bearing alloys, Ampco 483 (9Al-4.5Ni-bronze), 90-10 cupronickel, and 70-30 cupronickel, suffered severe (greater than 20 mpy) uniform or local attack. Dealloying of Ampco 8, Ampco 12, Ampco 483, and Muntz Metal (61Cu-39Zn) occurred under the TFE washer.

Titanium

Titanium (ASTM B 265 Gr2) was resistant to uniform corrosion. No local attack was observed.

Cobalt-Based Alloys

The Haynes 6B alloy was resistant to uniform corrosion. No local attack was observed.

Aluminum-Based Alloys

Three aluminum alloys, 1100, 5052, and 6061, were exposed in eleven-week trials. Uniform corrosion and localized corrosion were severe. Weight losses of more than 25 percent were observed after eleven weeks' exposure.

Based on the test results, the materials tested were divided into five categories (Miller 1977). The classification was based on uniform and crevice corrosion and pitting. Resistance to stress corrosion cracking and sulfide stress cracking was not considered. The results are shown in Table 4.18-5. Class 1 materials have the highest resistance to corrosion in Raft River fluid. Materials in Class 2 showed acceptable corrosion resistance. Class 3 materials had moderate corrosion rates, but are still useful as thick wall construction materials. Materials in Class 4 had high corrosion rates, and their usefulness is limited to special applications. Class 5 materials showed very little resistance to corrosion and are not useful, especially where crevices occur.

4.18.2.2 Tests of Potential Heat Exchanger Materials

Simulated tube-and-shell heat exchangers were exposed to RRGE 1 wellhead fluid for 34 days to investigate galvanic and crevice corrosion. Table 4.18-6 shows the tube and tube sheet combinations tested.

TABLE 4.18-5. CLASSIFICATION OF METALLIC CONSTRUCTION MATERIALS BY CORROSION RESISTANCE USING RESULTS OF COUPON TESTS AT RAFT RIVER, IDAHO, KGRA^a

<u>Class 1</u> <u>Most Resistant</u>	<u>Class 3</u> <u>Moderate Resistance</u>	<u>Class 5</u> <u>No Resistance</u>
Allegheny-Ludlum 29-4	AISI Type 316	AISI Type 410
Allegheny-Ludlum 29-4-2	Ampco 12 (9Al bronze)	AISI Type 440 ^b
Inconel 625		1100 Aluminum ^b
Haynes Alloy 6B		5052 Aluminum ^b
Titanium (ASTM B 265 Gr 2)		6061 Aluminum ^b
<u>Class 2</u> <u>Acceptable Resistance</u>	<u>Class-4</u> <u>Marginal Resistance</u>	
Allegheny-Ludlum 216	Gray cast iron	
Allegheny-Ludlum 6X	AISI 1018	
Hastelloy G	Low carbon steel plate	
Ampco 8 (7Al bronze)	AISI 4130	
Muntz Metal	COR-TEN	
	9Cr-steel	
	AISI Type 304	
	Ampco 483 (9Al-4.5Ni-bronze)	
	90-10 cupronickel	
	70-30 cupronickel	
	Monel 400	

^aCoupons were tested in fluid from Well RRGE 1 for varying periods up to 109 days. Classifications are based on calculated rates of uniform, pitting, and crevice corrosion.

^bAluminum coupons were exposed for 11 weeks, after which all showed severe corrosion and erosion.

Source: Miller 1977.

TABLE 4.18-6. TUBE-TO-TUBESHEET COMBINATIONS TESTED AT RAFT RIVER

TUBE MATERIAL	TUBESHEET MATERIAL	
	Low-Carbon Steel	Naval Brass
Low-Carbon Steel	Yes	No
AISI 304	Yes	No
AISI 316	Yes	No
Allegheny-Ludlum 6X	Yes	No
Admiralty Brass (AS)	No	Yes
70Cu/30Ni	Yes	Yes
Hastelloy G	Yes	No

Source: Miller 1977

Generally, no severe degradation due to galvanic and/or crevice corrosion was noted in the materials likely to be selected for use in Raft River heat exchangers. (No detailed results are available.) Some pitting (unquantified) was identified in the 70Cu/30Ni tubing, but this material is no longer considered for the boiler/preheater system. It showed excessive corrosion induced by hydrogen sulfide in the geothermal fluid (Miller 1977).

4.18.2.3 Field Tests with Nonmetallic Materials

See Section 5.6 for information concerning field tests at Raft River using asbestos cement pipe.

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4.19 SALTON SEA, CALIFORNIA

The Salton Sea (Niland) KGRA, located along the southwestern shore of the Salton Sea in southern California (see Figure 4.19-1), is the site of extensive materials testing and scale research. Wells tap very hot (greater than 660°F) water at depths of 4900 to 5900 feet (Ellis and Mahon 1977). This water has total dissolved solids (TDS) between 18 percent and 35 percent by weight. This is over ten times higher than the dissolved solids concentrations observed at any other geothermal resource. Various efforts have been made to recover minerals from this resource, but severe scaling problems have occurred.

Construction of a 10 MW thermal loop [Geothermal Loop Experimental Facility (GLEF)] began in 1975. Operation began in 1976. The loop was designed to demonstrate the feasibility of a quadruple flash, steam binary plant using the highly mineralized water at the Salton Sea.

The total flow from two producing wells was directed through five flash/steam separators. Two first-stage separators were designed to handle the mass flow from one producing well. The total brine flow from the first stage was directed to the second, third, and fourth stage separators in series. Steam produced by the flashing brine then flowed through a steam scrubber (one for each stage). The scrubbed steam was then directed through six heat exchangers. In this process, all of the generated steam was condensed. Ultimately, the condensed steam was reinjected or pumped to a storage tank. The noncondensable gas, primarily carbon dioxide, was exhausted to the atmosphere through a silencer. A 130-foot high stack dispersed the gas and met the Air Pollution Control Device (APCD) requirements for ground level concentration of hydrogen sulfide.

The brine from the last-stage steam separator was directly reinjected with the steam condensate through two injection wells located about 6000 feet from the facility.

Energy from the condensing steam vaporized the secondary or working fluid. The vapor was passed through a pressure control valve and then condensed in two water-cooled exchangers. The condensate was collected in a drum and recirculated through the heat exchangers (Bishop et al. 1976).

4.19.1 Fluid Chemistry

The Salton Sea geothermal fluid is the most mineralized known. Chloride concentration is on the order of 100,000 ppm. Sulfate concentration is less than 50 ppm. The steam fraction separated at 200 psig contains 0.1 to 1.0 percent (volume) noncondensable gases, mostly carbon dioxide. At production depths the dissolved carbon dioxide is approximately 7000 ppm, and hydrogen sulfide is approximately 16 ppm. Reservoir pH is 4.5 (Ellis and Mahon 1977). The fugacity of carbon dioxide is

FIGURE 4.19-1. LOCATION OF SALTON SEA GEOTHERMAL RESOURCE

about 37.5 psia (Helgeson 1968). Flashing partitions the carbon dioxide into the steam phase, and separated fluids have a pH of approximately 5 to 6. The composition of geothermal fluids from three wells in the Salton Sea KGRA is given in Table 4.19-1. These analyses were selected from 80 analyses of 21 wells presented by Cosner and Apps (1978). They represent the range of compositions observed at the Salton Sea.

4.19.2 Corrosion Tests

Extensive laboratory and field corrosion studies have been performed at the Salton Sea. Results are summarized in Screening Tables 4.19-2 through 4.19-10. Laboratory results are given in parentheses.

The following sections provide details about test conditions and results from the various test programs. Discussion of the applicability of various alloys is given. The field tests were all performed by various researchers at the GLEF. All used process steams derived from Magmamax No. 1. The laboratory tests used a synthetic geothermal fluid. The various tests will be discussed in the following order:

- qualitative corrosion tests in wellhead,
- tests at the Bureau of Mines Materials Test Facility (MTF),
- linear polarization measurements at the Bureau of Mines MTF,
- tests at the Lawrence Livermore Laboratories (LLL) corrosion test facility,
- laboratory tests (in synthetic fluid) by the Bureau of Mines, and
- tests at the Bureau of Mines MTF using nonmetallic materials.

4.19.2.1 Qualitative Corrosion Tests in Wellhead Fluid

Coupons of ten alloys (carbon steel, AISI 316L, E-Brite 26-1, Haynes Alloy 20 Mod, Carpenter 20Cb3, Inconel Alloy 625, Hastelloy G, Hastelloy C-276, commercially pure titanium, and TiCode 12) were exposed to wellhead fluid from Magmamax No. 1 for 30 days (Syrett et al. 1977). Published information about the test procedures did not include data on fluid composition.

TABLE 4.19-1. CHARACTERISTICS OF GEOTHERMAL FLUIDS FROM THREE
WELLS IN THE SALTON SEA KGRA

FLUID CHARACTERISTIC	WELL SINCLAIR 1 (Flashed Fluid)	WELL MAGMAMAX 1 (Flashed Fluid)	WELL IID 1 (Flashed Fluid and Condensate)
FLUID PROPERTIES			
Temperature (°F)	536	509	600
Depth of Well (ft)	690	2,900	5,200
Enthalpy (Btu/lb)	432	450	-
Conductance (μmhos/cm)	247,360	226,297	-
Specific Gravity (at 77°F)	1.114	-	-
CHEMICAL COMPOSITION			
<u>Key Species:</u>	pH		
	5.3	6.1	5.2
	<u>ppm</u>	<u>ppm</u>	<u>ppm</u>
Chloride (Cl ⁻)	93,650	120,374	155,000
Sulfate (SO ₄ ²⁻)	58	10	56
Bicarbonate (HCO ₃ ⁻)	60	4,472 ^a	150
Carbonate (CO ₃ ²⁻)	0	0	0
Hydrogen sulfide (H ₂ S)	-	-	16
Ammonia (NH ₃)	340	558	409
<u>Other Species:</u>	TDS ^b		
	183,700	203,406	237,800
Silica (SiO ₂)	350	426	400
Calcium (Ca)	14,550	23,090	28,000
Sodium (Na)	36,340	46,282	50,400
Potassium (K)	7,820	7,789	17,500
Magnesium (Mg)	780	108	54
Boron (B)	210	-	390
Iron (Fe)	166	168	2,290
Manganese (Mn)	410	-	4,100
Barium (Ba)	540	55	235
Strontium (Sr)	360	100	400

^aTotal carbon dioxide

^bTotal dissolved solids

Source: Cosner and Apps 1978

TABLE 4.19-2. CORROSION SCREENING RESULTS FOR SALTON SEA
WELLHEAD FLUID^a

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	D (G)	X (X)	N (N)	N (N)	(D)	(X)	(N)	(-)
AISI 4130	C-D (C)	X (N)	N (X)	N (N)	(D)	(-)	(-)	(-)
Cor-Ten A	C (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
Cor-Ten B	(B)	(X)	(X)	(-)	(D)	(X)	(-)	(-)
Mariner	D (B)	X (N)	- (N)	- (-)	(D)	(X)	(-)	(-)
<u>Stainless Steels</u>								
AISI 316L	A-C (A)	X (N)	X (X)	X, I (X)	(D)	(X)	(X)	(X)
AISI 410	C (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
AISI 430	A-B (A)	X (N)	N (N)	N (X)	(D)	(X)	(-)	(X)
E-Brite 26-1	A (A)	X (N)	N (N)	N (N)	(C)	(X)	(X)	(N)
Allegheny-Ludlum 6X	A-B (-)	X (-)	N (-)	N (-)	(-)	(-)	(-)	(-)
Allegheny-Ludlum 29-4	A (-)	X (-)	N (-)	N (-)	(-)	(-)	(-)	(-)
Sandvik 3RE60	(B)	(N)	(X)	(X)	(-)	(-)	(X)	(B)
Carpenter 20	(A)	(N)	(X)	(X)	(-)	(-)	(-)	(-)
<u>Nickel Base</u>								
Monel 400	C (C)	X (X)	- (N)	- (N)	(D)	(X)	(-)	(-)
Monel 404	C (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
Incoloy 825	B (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
Inconel 600	B (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
Inconel 625	A (A)	X (N)	N (X)	N (X)	(C)	(X)	(X)	(X)
Inconel X-750	(A)	(N)	(X)	(N)	(-)	(-)	(-)	(-)
Hastelloy S	A (A)	X (N)	N (X)	N (N)	(-)	(-)	(-)	(-)
Hastelloy G	A (A)	X (X)	N (X)	N (X)	(-)	(-)	(-)	(-)
Hastelloy C-276	A (A)	N (N)	N (N)	N (N)	(B)	(X)	(X)	(X)
<u>Titanium Base</u>								
Titanium	(A)	(X)	(X)	(N)	(A)	(X)	(N)	(X)
Ti-1.7W	(A)	(N)	(X)	(N)	(-)	(-)	(-)	(-)
Ti-1.5 Ni	A (A)	N (X)	N (X)	N (N)	(A)	(N)	(N)	(N)
Ti6Al4V	B (-)	X (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
Ti-10V	(A)	(X)	(X)	(N)	(-)	(-)	(-)	(-)
Ti-0.2 Pd	(A)	(X)	(N)	(N)	(A)	(N)	(N)	(B)
TiCode 12	A (A)	N (N)	N (N)	N (N)	(A)	(N)	(-)	(-)
Ti-50A	A (-)	N (-)	- (-)	- (-)	(-)	(-)	(-)	(-)
<u>Copper Base</u>								
70-30 Cupronickel	(B)	(N)	(N)	(N)	(D)	(X)	(X)	(-)
<u>Molybdenum Base</u>								
TZM	(A)	(N)	(N)	(N)	(-)	(-)	(-)	(-)

^aRefer to Table 4.19-3 for weld corrosion data obtained using wellhead fluid

A - Uniform corrosion rate < 1.0 mpy
 B - Uniform corrosion rate > 1.0 but < 10 mpy
 C - Uniform corrosion rate > 10 but < 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Data in parentheses are from laboratory results

Refer to Tables 4.19-13,-14,-27,-28,-29,-47,-48, and -50 for more detailed data.

TABLE 4.19-3. WELD CORROSION IN SALTON SEA KGRA - TYPE BRINE AT 450°F,
FIFTEEN-DAY EXPOSURE

MATERIAL TESTED	WELDING TECHNIQUE ^a	FILLER MATERIAL	CORROSION RATE			
			Deaerated		100 ppm Oxygen ^b	
			Weld	Nonweld	Weld	Nonweld
1020 Carbon Steel	Stick	E6011	C	C	D	D
AISI 4130	Stick	E5010	C	C	D	D
AISI 316L	TIG	AISI 316L	A ^c	A	D ^c	D
E-Brite 26-1	TIG	E-Brite 26-1	A	A	D	C
Ti-0.2 Pb	TIG	Ti-0.2 Pb	A	A	A	A
Ti-50A	TIG	Titanium	B	A	A	A
Inconel	TIG	Inconel 625	A	A	D	C

^a Stick - Shielded-metal arc welding
TIG - Tungsten-inert gas arc welding

^b Stress corrosion cracking of AISI 316L autoclaves terminated exposure after 5-7 days for samples in brine containing oxygen.

^c Stress corrosion cracks across weld.

KEY TO TABLE

A - Uniform corrosion rate ≤ 1.0 mpy
B - Uniform corrosion rate > 1.0 but ≤ 10 mpy
C - Uniform corrosion rate > 10 but ≤ 50 mpy
D - Uniform corrosion rate > 50 mpy

Refer to Table 4.19-49 for more detailed data.

TABLE 4.19-4. CORROSION SCREENING RESULTS FOR SALTON SEA FIRST FLASH FLUID

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C-D	X	N	N	-	-	-	-
AISI 4130	B	X	N	N	-	-	-	-
Cor-Ten A	B-C	X	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	C	X	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A-B	X	X	X, I	-	-	-	-
AISI 410	B	X	-	-	-	-	-	-
AISI 430	A-B	X	X	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
Allegheny-Ludlum 6X	A	X	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	X	N	N	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	B	X	-	-	-	-	-	-
Monel 404	B-C	X	-	-	-	-	-	-
Incoloy 825	A	X	-	-	-	-	-	-
Inconel 600	A-B	X	-	-	-	-	-	-
Inconel 625	A	X	N	N	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Hastelloy S	A	X	N	N	-	-	-	-
Hastelloy C	A	X	X	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti6Al4V	N	X	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	B	X	N	N	-	-	-	-
Ti-50A	N	N	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

A - Uniform corrosion rate ≤ 1.0 mpy
B - Uniform corrosion rate > 1.0 but ≤ 10 mpy
C - Uniform corrosion rate > 10 but ≤ 50 mpy
D - Uniform corrosion rate > 50 mpy
N - Indicated form of corrosion not detected
X - Indicated form of corrosion detected
I - Intergranular corrosion
- - Data not available

Refer to Tables 4.19-15, -16, -30, -31 and -32 for more detailed data.

TABLE 4.19-5. CORROSION SCREENING RESULTS FOR SALTON SEA FIRST FLASH STEAM

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C-D	X	N	N	-	-	-	-
AISI 4130	B-C	X	N	N	-	-	-	-
Cor-Ten A	B-C	X	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	B-C	X	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A-B	X	N	X, I	-	-	-	-
AISI 410	B	X	-	-	-	-	-	-
AISI 430	A-B	X	X	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
Allegheny-Ludlum 6X	A	X	N	N	-	-	-	-
Allegheny-Ludlum 29-4	A	X	N	N	-	-	-	-
Sandvik 3RE#0	-	-	-	-	-	-	-	-
Carpenter 10	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	B-C	X	-	-	-	-	-	-
Monel 404	B-C	X	-	-	-	-	-	-
Incoloy 825	A	X	-	-	-	-	-	-
Inconel 600	B	X	-	-	-	-	-	-
Inconel 625	A	X	N	N	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy C	A	X	X	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti6Al4V	N	N	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	A	N	N	N	-	-	-	-
Ti-50A	N	N	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - Uniform corrosion rate < 1.0 mpy
 B - Uniform corrosion rate > 1.0 but < 10 mpy
 C - Uniform corrosion rate > 10 but < 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Refer to Tables 4.19-17, -18, -33, -34, and -35 for more detailed data.

TABLE 4.19-6. CORROSION SCREENING RESULTS FOR SALTON SEA SCRUBBED FIRST FLASH STEAM

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C	X	X	N	-	-	-	-
AISI 4130	C	X	N	N	-	-	-	-
Cor-Ten A	-	-	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A	X	X	X, I	-	-	-	-
AISI 410	-	-	-	-	-	-	-	-
AISI 430	A	X	N	N	-	-	-	-
E-Brite 26-1	A	X	N	N	-	-	-	-
Allegheny-Ludlum 6X	A	X	N	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Monel 404	-	-	-	-	-	-	-	-
Incoloy 825	-	-	-	-	-	-	-	-
Inconel 600	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti6Al4V	-	-	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	A	N	N	N	-	-	-	-
Ti-50A	-	-	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

A - Uniform corrosion rate < 1.0 mpy
 B - Uniform corrosion rate > 1.0 but < 10 mpy
 C - Uniform corrosion rate > 10 but < 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Refer to Tables 4.19-19 and 4.19-20 for more detailed data.

TABLE 4.19-7. CORROSION SCREENING RESULTS FOR SALTON SEA SECOND FLASH FLUID

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C-D	X	N	N	-	-	-	-
AISI 4130	B-C	X	N	N	-	-	-	-
Cor-Ten A	B-C	X	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	B-C	X	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A	X	X	X, I	-	-	-	-
AISI 410	B	X	-	-	-	-	-	-
AISI 430	A	X	X	N	-	-	-	-
E-Brite 26-i	A	X	X	N	-	-	-	-
Allegheny-Radium 6X	A	X	N	N	-	-	-	-
Allegheny-Radium 29-4	A	X	N	N	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 18	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	B	X	-	-	-	-	-	-
Monel 404	B	X	-	-	-	-	-	-
Incoloy 825	A	X	-	-	-	-	-	-
Inconel 600	A-B	X	-	-	-	-	-	-
Inconel 625	A	X	N	N	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	X	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti6Al4V	N	X	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	A	N	N	N	-	-	-	-
Ti-50A	N	N	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - Uniform corrosion rate < 1.0 mpy
 B - Uniform corrosion rate > 1.0 but ≤ 10 mpy
 C - Uniform corrosion rate > 10 but ≤ 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Refer to Tables 4.19-21, -22, -36, -37, and -38 for more detailed data.

TABLE 4.19-8. CORROSION SCREENING RESULTS FOR SALTON SEA SECOND FLASH STEAM

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C	X	N	N	-	-	-	-
AISI 4130	B-C	X	N	N	-	-	-	-
Cor-Ten A	B-C	X	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	B	X	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A	X	X	X,I	-	-	-	-
AISI 410	B	X	-	-	-	-	-	-
AISI 430	A	X	X	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
Allegheny-Ludlum 6X	A	X	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	X	N	N	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	B	X	-	-	-	-	-	-
Monel 404	B	X	-	-	-	-	-	-
Incoloy 825	A	X	-	-	-	-	-	-
Inconel 600	A-B	X	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy C	A	X	X	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti6Al4V	N	N	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	A	N	N	N	-	-	-	-
Ti-50A	N	N	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
T2M	-	-	-	-	-	-	-	-

KEY TO TABLE

A - Uniform corrosion rate < 1.0 mpy
 B - Uniform corrosion rate > 1.0 but < 10 mpy
 C - Uniform corrosion rate > 10 but < 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Refer to Tables 4.19-23, -24, -39, -40, and -41 for more detailed data.

TABLE 4.19-9. CORROSION SCREENING RESULTS FOR SALTON SEA SCRUBBED SECOND FLASH STEAM

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	C-D	X	X	N	-	-	-	-
AISI 4130	C	X	X	N	-	-	-	-
Cor-Ten A	-	-	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A	X	X	X, I	-	-	-	-
AISI 410	-	-	-	-	-	-	-	-
AISI 430	B	X	X	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
Allegheny-Ludlum 6X	A	X	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Monel 434	-	-	-	-	-	-	-	-
Incoloy 825	-	-	-	-	-	-	-	-
Inconel 600	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Inconel K-750	-	-	-	-	-	-	-	-
Hastelloy S	A	N	X	N	-	-	-	-
Hastelloy G	A	N	X	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Nb	A	N	N	N	-	-	-	-
Ti6Al4V	-	-	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	A	N	N	N	-	-	-	-
Ti-50A	-	-	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Molybdenum Base</u>								
T2M	-	-	-	-	-	-	-	-

KEY TO TABLE

A - Uniform corrosion rate ≤ 1.0 mpy
 B - Uniform corrosion rate > 1.0 but ≤ 10 mpy
 C - Uniform corrosion rate > 10 but ≤ 50 mpy
 D - Uniform corrosion rate > 50 mpy
 N - Indicated form of corrosion not detected
 X - Indicated form of corrosion detected
 I - Intergranular corrosion
 - - Data not available

Refer to Tables 4.19-25 and 4.19-26 for more detailed data.

TABLE 4.19-10. CORROSION SCREENING RESULTS FOR CONCENTRATED GAS-FREE FLUID FROM 221°F AUTOCLAVE TESTS

MATERIAL TESTED	NON-AERATED FLUID				AERATED FLUID			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Low Alloy Iron Base</u>								
1020 Carbon Steel	B	N	-	-	B	N	-	-
AISI 4130	-	-	-	-	-	-	-	-
Cor-Ten A	-	-	-	-	-	-	-	-
Cor-Ten B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 316L	A	N	X	N	B	N	X	N
AISI 410	-	-	-	-	-	-	-	-
AISI 430	-	-	-	-	-	-	-	-
E-Brite 26-1	A	N	N	N	B	N	N	N
Allegheny-Ludlum 6X	-	-	-	-	-	-	-	-
Allegheny-Ludlum 29-4	-	-	-	-	-	-	-	-
Sandvik 3RE60	A	N	X	N	A	N	X	N
Carpenter 20	A	N	X	N	B	N	X	N
<u>Nickel Base</u>								
Monel 400	B	N	X	N	B	N	X	N
Monel 404	-	-	-	-	-	-	-	-
Incoloy 825	-	-	-	-	-	-	-	-
Inconel 600	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	A	N	N	N
Inconel X-750	A	N	X	N	B	N	X	N
Hastelloy S	A	N	N	N	A	N	X	N
Hastelloy G	A	N	N	N	A	N	X	N
Hastelloy C-276	A	N	N	N	A	N	N	N
<u>Titanium Base</u>								
Titanium	A	N	N	N	A	N	X	N
Ti-1.7W	A	N	N	N	A	N	N	N
Ti-1.5Ni	A	N	N	N	A	N	N	N
Ti6Al4V	-	-	-	-	-	-	-	-
Ti-10V	A	N	N	N	A	N	N	N
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode 12	-	-	-	-	-	-	-	-
Ti-50A	-	-	-	-	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	A	N	X	N	B	N	X	N
Cu-2Fe	B	N	-	-	C	N	-	-
Copper	B	N	N	N	C	N	N	N
<u>Aluminum Base</u>								
2024-T3	B	X	X	*	C	N	X	*
6061-T6	C	X	N	*	D	N	N	*
<u>Molybdenum Base</u>								
T2M	A	N	N	N	B	N	X	N

KEY TO TABLE

A - Uniform corrosion rate ≤ 1.0 mpy
B - Uniform corrosion rate > 1.0 but ≤ 10 mpy
C - Uniform corrosion rate > 10 but ≤ 50 mpy
D - Uniform corrosion rate > 50 mpy
N - Indicated form of corrosion not detected
X - Indicated form of corrosion detected
I - Intergranular corrosion
- - Data not available
* - Greatly increased uniform corrosion in stressed area

Refer to Table 4.19-50 for more detailed data.

The carbon steel coupon exhibited the highest corrosion rate. It was visibly smaller at the end of the test and disintegrated when handled. The coupons were not descaled, so weight loss data could not be used to calculate uniform corrosion rates. None of the stainless steel, nickel-based, or titanium alloys appeared to have suffered significant corrosion. AISI 316L, Haynes Alloy 20 Mod, Carpenter 20Cb3, and E-Brite 26-1 were pitted. No pitting was observed on the other specimens.

4.19.2.2 Tests at the Bureau of Mines MTF

Methods

Corrosion rates were measured in two separate field tests conducted at the Bureau of Mines Test Facility at the Geothermal Loop Experimental Facility (GLEF). The test facility employed fluid from well Magmamax No. 1 in seven process streams typical of those in a dual flash steam binary power cycle (wellhead, first and second flash fluid, first and second flash steam, and scrubbed first and second flash steam). The 1976/1977 field test data includes corrosion rates measured during two 15-day periods and one 30-day period for fluids from all seven process streams. Fluid characteristics of these streams are summarized in Table 4.19-11. Corrosion data from the 1978 field test were collected for 15-, 30-, and 45-day periods for five process streams, excluding the scrubbed first and second flash steam. Table 4.19-12 contains characteristics of the five process stream fluids.

Coupons of commercially available alloys were tested for weight-loss and evidence of pitting and crevice corrosion. Thirteen alloys were included in the 1976/1977 field test, while twenty were used for the 1978 field test. The coupons were fastened to rods using insulating washers designed to minimize crevice areas. The flow through the test area was highly turbulent, resulting in thorough and relatively uniform exposure of the corrosion samples to the fluid. Poorly adherent scale deposits were generally stripped away due to the high shear stresses.

Results and Discussion

Uniform corrosion rates based on weight-loss and pitting rates based on maximum pit depth are given in Tables 4.19-13 to 4.19-41 for each material tested. Crevice corrosion and stress corrosion cracking are indicated either by X (detected) or N (not detected). There are no crevice corrosion or stress corrosion cracking (SCC) data available from the 1978 field test.

In general, uniform corrosion and pitting rates were much greater during the 1978 field test than during the 1976/1977 field test. The 1976/1977 test data indicate no pitting occurred on nickel or titanium

TABLE 4.19-11. MEAN OPERATING CONDITIONS DURING 1976/1977 FIELD TEST AT
SALTON SEA KGRA

PROCESS STREAM	FLUID CHARACTERISTICS ^a			
	Temperature °F	Pressure psig	Chloride ppm	pH ^b
Wellhead Fluid	444	302	118,200	5.11
First Flash Fluid	405	225	123,000	5.68
First Flash Steam	405	224	9,500	5.88
Scrubbed First Flash Steam	212	15	170 ^c	-
Second Flash Fluid	352	140	128,000	5.73
Second Flash Steam	352	140	8,620	6.70
Scrubbed Second Flash Steam	212	15	360 ^c	-

^a Average flowrate from Magmamax No. 1 was 45 gpm

^b Measured in fluid sample cooled to 77°F

^c Valve is questionable

Source: Carter et al. 1979

TABLE 4.19-12. MEAN OPERATING CONDITIONS FOR 1978 FIELD TEST AT SALTON SEA KGRA

PROCESS STREAM	FLUID CHARACTERISTICS									
	15 DAYS				30 DAYS			45 DAYS		
	Temperature °F	Pressure psig	Chloride ppm	pH ^a	Temperature °F	Pressure psig	Chloride ppm	Temperature °F	Pressure psig	Chloride ppm
Wellhead Fluid	424	272	115,000	5.3	419	267	119,000	412	290	112,000
First Flash Fluid	381	222	122,000	5.7	392	222	136,000	396	222	122,000
First Flash Steam	381	222	12,000	6.2	392	222	6,500	396	222	5,900
Second Flash Fluid	360	129	128,000	5.8	358	134	138,000	351	135	122,000
Second Flash Steam	360	129	2,400	6.9	358	134	1,600	351	135	1,000
Flow Rate (GPM)		28.0				32.8			41.2	

^a Measured in fluid sample cooled to 77°F.

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-13. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING WELLHEAD FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	67	178 ^g	N	N
AISI 4130	13-33 ^f	148 ^{g,h}	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.7	68 ^g	X	X ⁱ
AISI 430	0.6-2.2 ^f	102 ^g	N	N
E-Brite 26-1	0.2	85 ^g	N	N
Allegheny-Ludlum 6X	<0.1	N	N	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	N	N	N	N
TiCode 12	N	N	N	N

^a444°F, 302 psig, pH 5.11, chloride 118,200 ppm.

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress-corrosion cracking (not differentiated as to mechanism). Based on microscopic examination

^fResults of two trials reported separately

^gWidth of pits is 4 to 5 times the depth

^hEdge pitting

ⁱSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

SOURCES: Carter^o et al. 1979; Carter and McCawley (undated)

TABLE 4.19-14. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING WELLHEAD FLUID FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	43	273 ^g	N	N
AISI 4130	4-37 ^f	86 ^g	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.3	37 ^h	X	X ^{i,j}
AISI 430	0.5	46	N	N
E-Brite 26-1	0.2	43	N	N
Allegheny-Ludlum 6X	<0.2	18	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy G	<0.2	N	N	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	0.7	N	N	N

^a444°F, 302 psig, pH 5.11, chloride 118,200 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress-corrosion cracking (not differentiated as to mechanism). Based on microscopic examination.

^fResults of two trials reported separately

^gEdge pitting

^hPit depth increased by factor of 5 compared to the fifteen-day test.

ⁱSevere transgranular corrosion observed. Cracks completely perforate sample.

^jSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-15. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	27-62 ^f	287 ^g	N	N
AISI 4130	3.6-6.8 ^f	102 ^g	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.1	27 ^g	X	X ^h
AISI 430	0.2	80 ^g	X	N
E-Brite 26-1	0.2	114 ^g	X	N
Allegheny-Ludlum 6X	<0.1	N	X	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	N	N	N	N

^a405°F, 224 psig, pH 5.68, chloride 123,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking

^fResults of two trials reported separately

^gWidth of pits is 4 to 5 times the depth

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979; Carter and McCawley (undated)

TABLE 4.19-16. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING FIRST FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	42	174 ^g	N	N
AISI 4130	6.6-57 ^f	99	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.4	37 ^h	X	X ^{i,j}
AISI 430	0.3	38	X	N
E-Brite 26-1	0.3	61	X	N
Allegheny-Ludlum 6X	<0.2	12	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy G	<0.2	N	X	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	1.9	N	N	N

^a405°F, 224 psig, pH 5.68, chloride 123,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination

^fResults of two trials reported separately

^gEdge pitting

^hPit depth increased by a factor of 5 compared to the fifteen-day test

ⁱSevere transgranular corrosion observed. Cracks completely perforated sample

^jSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-17. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	26	151 ^{f,g}	N	N
AISI 4130	7.7	78 ^f	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.4	32 ^f	N	X ^h
AISI 430	0.8	88 ^f	X	N
E-Brite 26-1	0.3	90 ^f	X	N
Allegheny-Ludlum 6X	<0.1	39 ^f	N	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	N	N	N	N

^a405°F, 224 psig, pH 5.88, chloride 9,500 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fWidth of pits is 4 to 5 times the depth

^gEdge pitting

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979; Carter and McCawley (undated)

TABLE 4.19-18. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	28	146 ^f	N	N
AISI 4130	13	73 ^f	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.2	71 ^{g,h}	N	X ^{i,j}
AISI 430	2.0	51	X	N
E-Brite 26-1	0.3	51	X	N
Allegheny-Ludlum 6X	<0.2	24	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy G	<0.2	N	X	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	1.9	N	N	N

^a 405°F, 224 psig, pH 5.88, chloride 9,500 ppm

^b Based on weight loss

^c Based on maximum pit depth

^d Effort made to minimize crevice area

^e Stress corrosion cracking (not differentiated as to mechanism)
Based on microscopic examination.

^f Edge pitting

^g Pit depth increased by a factor of 5 compared to the fifteen-day test

^h Pitting rate more than 200 times the uniform corrosion rate

ⁱ Severe transgranular corrosion observed. Cracks completely perforate samples

^j Severe intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-19. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING
SCRUBBED FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN
THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform ^b Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice ^d Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	21-40 ^f	83 ^g	X	N
AISI 4130	18	97 ^g	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.2	127 ^g	X	X ^h
AISI 430	0.4	122 ^g	N	N
E-Brite 26-1	0.2	56 ^g	N	N
Allegheny-Ludlum 6X	<0.1	37 ^g	N	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	N	N	N	N
TiCode 12	-	-	-	-

^a212°F, 15 psig, pH not known, chloride 170 ppm (questionable). Conditions were controlled poorly, and results are uncertain.

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism). Based on microscopic examination.

^fResults of two trials reported separately

^gWidth of pits is 4 to 5 times the depth

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979; Carter and McCawley (undated)

TABLE 4.19-20. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING SCRUBBED FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	25	141	N	N
AISI 4130	18	125	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.2	78 ^f	X	X ^{g,h}
AISI 430	1.0	127	N	N
E-Brite 26-1	0.3	91	N	N
Allegheny-Ludlum 6X	<0.2	47	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy C	<0.2	N	N	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	0.6	N	N	N
TiCode 12	0.5	N	N	N

^a212°F, 15 psig, pH not known, chloride 170 ppm (questionable).
Conditions were controlled poorly, and results are uncertain.

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fPit depth increased by a factor of 5 compared to the fifteen-day tests.

^gTransgranular corrosion observed

^hIntergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-21. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SECOND FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	48	236 ^g	N	N
AISI 4130	2.2-10.3 ^f	87 ^g	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.3	44 ^g	X	X ^h
AISI 430	0.6	41 ^g	X	N
E-Brite 26-1	N	39 ^g	X	N
Allegheny-Ludlum 6X	<0.1	29 ^g	N	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	0.3	N	N	N

^a352°F, 140 psig, pH 5.73, chloride 128,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fResults of two trials reported separately

^gWidth of pits is 4 to 5 times the depth

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter, et al. 1979; Carter and McCawley (undated)

TABLE 4.19-22. CORROSION TESTS MEASURED IN THIRTY-DAY TESTS USING SECOND FLASH FLUID, FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	39	165 ^f	N	N
AISI 4130	3.1	106	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.2	55 ^g	N	X ^{h,i}
AISI 430	1.1	56	X	N
E-Brite 26-1	0.1	45	X	N
Allegheny-Ludlum 6X	<0.2	37	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy G	<0.2	N	N	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	1.1	N	N	N

^a 352°F, 140 psig, pH 5.73, chloride 128,000 ppm

^b Based on weight loss

^c Based on maximum pit depth

^d Effort made to minimize crevice area

^e Stress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^f Edge pitting

^g Pit depth increased by factor of 5 compared to the fifteen-day tests.

^h Severe transgranular corrosion observed. Cracks completely perforated sample.

ⁱ Severe intergranular corrosion observed.

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-23. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING
SECOND FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON
SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	25	202 ^f	N	N
AISI 4130	8.2	110 ^f	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.3	83 ^f	X	X ^g
AISI 430	0.5	100 ^f	X	N
E-Brite 26-1	0.3	102 ^f	X	N
Allegheny-Ludlum 6X	<0.1	37 ^f	X	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	N	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	0.7	N	N	N

^a352°F, 140 psig, pH 6.70, chloride 8,620 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fWidth of pits is 4 to 5 times the depth

^gSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979; Carter and McCawley (undated)

TABLE 4.19-24. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING SECOND FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	28	169	N	N
AISI 4130	12	113	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.5	72 ^f	X	X ^{g,h}
AISI 430	1.2	111	X	N
E-Brite 26-1	0.4	90	X	N
Allegheny-Ludlum 6X	<0.2	35	X	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	N	N
Hastelloy G	<0.2	N	X	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	1.8	N	N	N

^a352 °F, 140 psig, pH 6.70, chloride 8,620 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fPit depths increased by a factor of 5 compared to the fifteen-day test.

^gSevere transgranular corrosion observed. Cracks completely perforated sample.

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-25. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SCRUBBED SECOND FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
LOW ALLOY IRON BASE				
1020 Carbon Steel	18-27 ^f	139 ^g	X	N
AISI 4130	25	153 ^g	X	N
STAINLESS STEEL				
AISI 316L	0.2	265 ^g	X	X ^h
AISI 430	1.4	304 ^g	X	N
E-Brite 26-1	0.1	238 ^g	X	N
Allegheny-Ludlum 6X	<0.1	29 ^g	X	N
Allegheny-Ludlum 29-4	<0.1	N	N	N
NICKEL BASE				
Inconel 625	<0.1	N	N	N
Hastelloy S	<0.1	N	X	N
Hastelloy G	<0.1	N	N	N
Hastelloy C-276	<0.1	N	N	N
TITANIUM BASE				
Ti-1.5 Ni	-	-	-	-
TiCode 12	-	-	-	-

^a212°F, 15 psig, pH not known, chloride 360 ppm (questionable).
Conditions were controlled poorly, and results are uncertain.

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fResults of two trials reported separately

^gWidth of pits 4 to 6 times the depth

^hSevere intergranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979; Carter and McCawley (undated)

TABLE 4.19-26. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING SCRUBBED SECOND FLASH STEAM FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1976/1977 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	30-79 ^f	85 ^g	N	N
AISI 4130	27-52 ^f	78 ^g	N	N
<u>STAINLESS STEEL</u>				
AISI 316L	0.3-1.0 ^f	268 ^{g,h}	N	X ^{1,j}
AISI 430	3.9-7.8 ^f	155 ^g	N	N
E-Brite 26-1	0.4	175 ^g	N	N
Allegheny-Ludlum 6X	<0.2	19	N	N
Allegheny-Ludlum 29-4	<0.2	N	N	N
<u>NICKEL BASE</u>				
Inconel 625	<0.2	N	N	N
Hastelloy S	<0.2	N	X	N
Hastelloy G	<0.2	N	X	N
Hastelloy C-276	<0.2	N	N	N
<u>TITANIUM BASE</u>				
Ti-1.5 Ni	-	-	-	-
TiCode 12	-	-	-	-

^a212°F, 15 psig, pH not known, chloride 360 ppm (questionable).
Conditions were controlled poorly, and results are uncertain.

^bBased on weight loss

^cBased on maximum pit depth

^dEffort made to minimize crevice area

^eStress corrosion cracking (not differentiated as to mechanism).
Based on microscopic examination.

^fResults of two trials reported separately

^gEdge pitting

^hPit depths increased by factor of 5 compared to the fifteen-day test.

ⁱIntergranular corrosion observed

^jTransgranular corrosion observed

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Carter et al. 1979

TABLE 4.19-27. CORROSION RATES IN FIFTEEN-DAY TESTS USING WELLHEAD FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	87	585	-	-
AISI 4130	46	>1170 ^d	-	-
Cor-Ten A	50	588	-	-
Mariner	55	546	-	-
STAINLESS STEELS				
AISI 316L	16.2	293	-	-
AISI 410	26	515	-	-
AISI 430	12	512	-	-
E-Brite 26-1	4.2	680	-	-
Allegheny-Ludlum 6X	5.0	263	-	-
Allegheny-Ludlum 29-4	1.1	470	-	-
NICKEL BASE				
Monel 400	28.2	58.1	-	-
Monel 404	30.2	42.3	-	-
Incoloy 825	4.6	192	-	-
Inconel 600	7.4	124	-	-
Inconel 625	0.2	137	-	-
Hastelloy G	0.6	208	-	-
Hastelloy S	0.2	108	-	-
TITANIUM BASE				
Ti-50A	0.1	26.4	-	-
TiCode 12	0.4	N	-	-
Ti6Al4V	4.2	47.5	-	-

^a424°F, 272 psig, pH 5.3, chloride 115,000 ppm. The values are averages of four fifteen-day tests.

^bBased on weight loss

^cBased on maximum pit depth

^dPits perforated samples

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-28. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING THE WELLHEAD FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA
KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	99	273 ^d	-	-
AISI 4130	58	>454 ^d	-	-
Cor-Ten A	41	224	-	-
Mariner	88	253	-	-
STAINLESS STEELS				
AISI 316L	6.7	159	-	-
AISI 410	31	320	-	-
AISI 430	6.9	195	-	-
E-Brite 26-1	1.3	262	-	-
Allegheny-Ludlum 6X	0.6	54.2	-	-
Allegheny-Ludlum 29-4	0.1	66.8	-	-
NICKEL BASE				
Monel 400	21	17.6	-	-
Monel 404	17	35.3	-	-
Incoloy 825	2.9	88.3	-	-
Inconel 600	4.0	23.9	-	-
Inconel 625	N	86.9	-	-
Hastelloy G	N	30.3	-	-
Hastelloy S	N	N	-	-
TITANIUM BASE				
Ti-50A	1.8	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	3.4	18.9	-	-

^a419°F, 267 psig, chloride 119,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dPits perforated samples

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-29. CORROSION RATES MEASURED IN FORTY-FIVE DAY TESTS USING WELLHEAD FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	95	212	-	-
AISI 4130	29	137	-	-
Cor-Ten A	18	93	-	-
Mariner	14	83.6	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	3.1	97.3	-	-
AISI 410	11	122	-	-
AISI 430	7.5	113	-	-
E-Brite 26-1	1.2	182	-	-
Allegheny-Ludlum 6X	0.7	163	-	-
Allegheny-Ludlum 29-4	0.2	63.2	-	-
<u>NICKEL BASE</u>				
Monel 400	14	13.7	-	-
Monel 404	11	12.8	-	-
Incoloy 825	1.4	40.1	-	-
Inconel 600	2.8	19.7	-	-
Inconel 625	0.1	17.9	-	-
Hastelloy G	0.1	30.7	-	-
Hastelloy S	N	11.1	-	-
<u>TITANIUM BASE</u>				
Ti-50A	0.8	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	6.3	N	-	-

^a412°F, 290 psig, chloride 112,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-30. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH FLUID FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	46	635	-	-
AISI 4130	15	311	-	-
Cor-Ten A	18	276	-	-
Mariner	18	335	-	-
STAINLESS STEELS				
AISI 316L	3.7	321	-	-
AISI 410	7.7	225	-	-
AISI 430	1.0	242	-	-
E-Brite 26-1	0.7	303	-	-
Allegheny-Ludlum 6X	0.6	121	-	-
Allegheny-Ludlum 29-4	0.2	245	-	-
NICKEL BASE				
Monel 400	8.2	66	-	-
Monel 404	13.5	55.5	-	-
Incoloy 825	0.3	247	-	-
Inconel 600	1.5	71.2	-	-
Inconel 625	N	44.8	-	-
Hastelloy G	N	51.9	-	-
Hastelloy S	N	55.3	-	-
TITANIUM BASE				
Ti-50A	N	15.8	-	-
TiCode 12	N	21.1	-	-
Ti6Al4V	N	29.0	-	-

^a 381°F, 222 psig, pH 5.7, chloride 122,000 ppm. The values are averages of four fifteen-day tests.

^b Based on weight loss

^c Based on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-31. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING FIRST FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	36	203	-	-
AISI 4130	14	154	-	-
Cor-Ten A	14	125	-	-
Mariner	18	199	-	-
STAINLESS STEELS				
AISI 316L	2.5	117	-	-
AISI 410	8.4	149	-	-
AISI 430	4.4	135	-	-
E-Brite 26-1	1.2	150	-	-
Allegheny-Ludlum 6X	0.6	66.8	-	-
Allegheny-Ludlum 29-4	0.2	30.3	-	-
NICKEL BASE				
Monel 400	4.4	29	-	-
Monel 404	7.5	54.2	-	-
Incoloy 825	0.4	41.6	-	-
Inconel 600	1.2	35.3	-	-
Inconel 625	N	17.7	-	-
Hastelloy G	N	N	-	-
Hastelloy S	N	8.8	-	-
TITANIUM BASE				
Ti-50A	N	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	N	34	-	-

^a392°F, 222 psig, chloride 136,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-32. CORROSION RATES MEASURED IN FORTY-FIVE DAY TESTS USING FIRST FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	28	133	-	-
AISI 4130	10	59	-	-
Cor-Ten A	6.5	75.1	-	-
Mariner	5.8	136	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	0.8	67.4	-	-
AISI 410	5.5	64	-	-
AISI 430	1.8	78	-	-
E-Brite 26-1	0.4	44.4	-	-
Allegheny-Ludlum 6X	0.1	26.5	-	-
Allegheny-Ludlum 29-4	0.1	60.6	-	-
<u>NICKEL BASE</u>				
Monel 400	3.6	30.7	-	-
Monel 404	6.0	21.3	-	-
Incoloy 825	0.1	45.3	-	-
Inconel 600	0.7	14.5	-	-
Inconel 625	N	8.5	-	-
Hastelloy G	N	9.4	-	-
Hastelloy S	N	3.4	-	-
<u>TITANIUM BASE</u>				
Ti-50A	N	N	-	-
Ti6Al4V	N	6.0	-	-
Ti6Al4V	N	5.1	-	-

^a396°F, 222 psig, chloride 122,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-33. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform ^b Corrosion (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	55	696	-	-
AISI 4130	32	417	-	-
Cor-Ten A	26	375	-	-
Mariner	19	410	-	-
STAINLESS STEELS				
AISI 316L	2.1	222	-	-
AISI 410	11	287	-	-
AISI 430	3.5	240	-	-
E-Brite 26-1	0.9	292	-	-
Allegheny-Ludlum 6X	1.2	148	-	-
Allegheny-Ludlum 29-4	0.2	106	-	-
NICKEL BASE				
Monel 400	15.5	58.1	-	-
Monel 404	21.2	84.6	-	-
Incoloy 825	0.9	111	-	-
Inconel 600	2.9	70.1	-	-
Inconel 625	0.1	68.5	-	-
Hastelloy G	0.1	60.6	-	-
Hastelloy S	0.4	21.1	-	-
TITANIUM BASE				
Ti-50A	N	21.1	-	-
TiCode 12	0.1	N	-	-
Ti6AL4V	0.1	N	-	-

^a381°F, 222 psig, pH 6.2, chloride 12,000 ppm. The values are averages of four fifteen-day tests

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-34. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING FIRST FLASH STEAM FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	67	276 ^d	-	-
AISI 4130	40	>454 ^d	-	-
Cor-Ten A	25	144	-	-
Mariner	20	241	-	-
STAINLESS STEELS				
AISI 316L	1.9	145	-	-
AISI 410	10	174	-	-
AISI 430	4.5	134	-	-
E-Brite 26-1	1.3	263	-	-
Allegheny-Ludlum 6X	0.7	42.9	-	-
Allegheny-Ludlum 29-4	0.3	94.6	-	-
NICKEL BASE				
Monel 400	9.8	17.7	-	-
Monel 404	12.0	37.8	-	-
Incoloy 825	1.2	45.4	-	-
Inconel 600	1.9	21.4	-	-
Inconel 625	0.2	42.9	-	-
Hastelloy G	N	45.4	-	-
Hastelloy S	0.1	N	-	-
TITANIUM BASE				
Ti-50A	N	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	N	N	-	-

^a 392°F, 222 psig, chloride 6,500 ppm

^b Based on weight loss

^c Based on maximum pit depth

^d Pits perforated samples

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-35. CORROSION RATES MEASURED IN FORTY-FIVE-DAY TESTS USING
FIRST FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON
SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	39	96	-	-
AISI 4130	18	85	-	-
Cor-Ten A	8.0	62.3	-	-
Mariner	6.9	92.2	-	-
STAINLESS STEELS				
AISI 316L	1.9	71.7	-	-
AISI 410	6.2	86	-	-
AISI 430	2.8	86	-	-
E-Brite 26-1	0.8	104	-	-
Allegheny-Ludlum 6X	0.6	28.2	-	-
Allegheny-Ludlum 29-4	0.3	31.6	-	-
NICKEL BASE				
Monel 400	7.5	22.2	-	-
Monel 404	8.5	16.2	-	-
Incoloy 825	0.7	32.5	-	-
Inconel 600	1.8	-	-	-
Inconel 625	0.1	14.5	-	-
Hastelloy G	N	15.8	-	-
Hastelloy S	N	N	-	-
TITANIUM BASE				
Ti-50A	0.2	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	N	N	-	-

^a396°F, 222 psig, chloride 5,900 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-36. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SECOND FLASH FLUID FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	75	888	-	-
AISI 4130	23	726	-	-
Cor-Ten A	25	359	-	-
Mariner	16	441	-	-
STAINLESS STEELS				
AISI 316L	-	198	-	-
AISI 410	5.6	277	-	-
AISI 430	0.5	206	-	-
E-Brite 26-1	0.3	409	-	-
Allegheny-Ludlum 6X	N	113	-	-
Allegheny-Ludlum 29-4	0.2	145	-	-
NICKEL BASE				
Monel 400	-	92.4	-	-
Monel 404	-	111	-	-
Incoloy 825	0.3	73.9	-	-
Inconel 600	2.0	111	-	-
Inconel 625	0.3	36.3	-	-
Hastelloy C	0.1	84.6	-	-
Hastelloy S	N	N	-	-
TITANIUM BASE				
Ti-50A	0.1	N	-	-
TiCode 12	0.1	N	-	-
Ti6Al4V	N	158	-	-

^a360°F, 129 psig, pH 5.8, chloride 128,000 ppm. The values are averages of four fifteen-day tests.

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-37. CORROSION RATES MEASURED IN THIRTY-DAY TESTS USING SECOND FLASH FLUID FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	58	339	-	-
AISI 4130	19	202	-	-
Cor-Ten A	17	174	-	-
Mariner	7.8	195	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	0.2	81.9	-	-
AISI 410	1.8	83	-	-
AISI 430	0.4	103	-	-
E-Brite 26-1	0.2	120	-	-
Allegheny-Ludlum 6X	N	25.2	-	-
Allegheny-Ludlum 29-4	-	85.7	-	-
<u>NICKEL BASE</u>				
Monel 400	4.6	23.9	-	-
Monel 404	4.5	25.2	-	-
Incoloy 825	0.3	39.1	-	-
Inconel 600	0.8	42.9	-	-
Inconel 625	-	10.1	-	-
Hastelloy G	-	10.1	-	-
Hastelloy S	N	N	-	-
<u>TITANIUM BASE</u>				
Ti-50A	N	N	-	-
TiCode 12	N	22.7	-	-
Ti6Al4V	N	N	-	-

^a358°F, 134 psig, chloride 138,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-38. CORROSION RATES MEASURED IN FORTY-FIVE-DAY TESTS USING SECOND FLASH FLUID FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST.

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform ^b Corrosion (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
LOW ALLOY IRON BASE				
1020 Carbon Steel	40	183	-	-
AISI 4130	4.7	56	-	-
Cor-Ten A	6.3	71.7	-	-
Mariner	3.6	136	-	-
STAINLESS STEELS				
AISI 316L	0.1	60.6	-	-
AISI 410	6.7	51	-	-
AISI 430	0.2	72	-	-
E-Brite 26-1	0.1	69.1	-	-
Allegheny-Ludlum 6X	N	33.3	-	-
Allegheny-Ludlum 29-4	N	31.6	-	-
NICKEL BASE				
Monel 400	2.8	16.2	-	-
Monel 404	3.2	17.9	-	-
Incoloy 825	0.1	28.2	-	-
Inconel 600	0.9	11.1	-	-
Inconel 625	0.1	11.1	-	-
Hastelloy G	N	33.3	-	-
Hastelloy S	N	N	-	-
TITANIUM BASE				
Ti-50A	N	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	N	N	-	-

^a350°F, 135 psig, chloride 122,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-39. CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SECOND FLASH STEAM FROM MAGMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	17	327	-	-
AISI 4130	11	359	-	-
Cor-Ten A	13	242	-	-
Mariner	8.9	322	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	1.0	150	-	-
AISI 410	5.7	198	-	-
AISI 430	0.4	209	-	-
E-Brite 26-1	0.2	198	-	-
Allegheny-Ludlum 6X	N	65.9	-	-
Allegheny-Ludlum 29-4	0.1	116	-	-
<u>NICKEL BASE</u>				
Monel 400	-	92.4	-	-
Monel 404	-	94.9	-	-
Incoloy 825	0.3	89.4	-	-
Inconel 600	1.4	55.5	-	-
Inconel 625	N	31.6	-	-
Hastelloy G	N	104	-	-
Hastelloy S	N	31.4	-	-
<u>TITANIUM BASE</u>				
Ti-50A	N	N	-	-
TiCode 12	0.1	N	-	-
Ti6Al4V	N	50.2	-	-

^a360°F, 129 psig, pH 6.9, chloride 2,400 ppm. Values are averages of four fifteen-day tests.

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-40. CORROSION RATES IN THIRTY-DAY TESTS USING SECOND FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform ^b Corrosion (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	43	362	-	-
AISI 4130	18	165	-	-
Cor-Ten A	12	112	-	-
Mariner	9.9	169	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	1.3	63	-	-
AISI 410	4.6	93	-	-
AISI 430	0.9	130	-	-
E-Brite 26-1	0.5	247	-	-
Allegheny-Ludlum 6X	N	101	-	-
Allegheny-Ludlum 29-4	N	27.7	-	-
<u>NICKEL BASE</u>				
Monel 400	3.7	24.0	-	-
Monel 404	4.6	18.9	-	-
Incoloy 825	0.5	61.8	-	-
Inconel 600	1.2	30.3	-	-
Inconel 625	0.2	N	-	-
Hastelloy G	N	31.5	-	-
Hastelloy S	N	N	-	-
<u>TITANIUM BASE</u>				
Ti-50A	N	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	0.1	N	-	-

^a358°F, 134psig, chloride 1,600 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

TABLE 4.19-41. CORROSION RATES MEASURED IN FORTY-FIVE-DAY TESTS USING SECOND FLASH STEAM FROM MAGMAMAX NO. 1 IN THE SALTON SEA KGRA - 1978 FIELD TEST

MATERIAL TESTED	CORROSION RATE IN NON-AERATED FLUID ^a			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion	SCC
<u>LOW ALLOY IRON BASE</u>				
1020 Carbon Steel	19	69	-	-
AISI 4130	13	66	-	-
Cor-Ten A	10	58.9	-	-
Mariner	4.6	119	-	-
<u>STAINLESS STEELS</u>				
AISI 316L	1.4	42.7	-	-
AISI 410	1.5	63	-	-
AISI 430	0.2	44	-	-
E-Brite 26-1	0.2	29.9	-	-
Allegheny-Ludlum 6X	N	17.0	-	-
Allegheny-Ludlum 29-4	0.1	30.7	-	-
<u>NICKEL BASE</u>				
Monel 400	2.2	13.7	-	-
Monel 404	3.1	19.6	-	-
Incoloy 825	0.3	31.6	-	-
Inconel 600	0.9	41.0	-	-
Inconel 625	0.1	N	-	-
Hastelloy G	N	14.5	-	-
Hastelloy S	N	N	-	-
<u>TITANIUM BASE</u>				
Ti-50A	N	N	-	-
TiCode 12	N	N	-	-
Ti6Al4V	N	N	-	-

^a350°F, 135 psig, chloride 1,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

KEY TO TABLE

N - Indicated form of corrosion not detected

X - Indicated form of corrosion observed but not quantified

- - Data not available

SOURCE: Cramer, Carter, and Conrad 1980

alloys, and uniform corrosion rates were virtually zero. Uniform corrosion rates from the 1978 field test were much higher (0.2 to 30.2 mpy), and pitting occurred on most of the nickel and titanium alloys in all streams. However, the uniform corrosion and pitting rates for the nickel and titanium alloys were still quite low, relative to the rates for the low alloy, iron-based materials.

Probably the most important finding of the 1978 tests was that for the low alloy steels, stainless steels, and nickel based alloys, essentially all pit growth occurred within the first fifteen-day test period. The results indicate very little if any additional growth with longer exposures.

Although precautions were taken to minimize crevices at coupon fastenings, crevice corrosion occurred on the stainless steels and some of the nickel alloys, such as Hastelloy G and Hastelloy S, in several process streams. Both pitting and uniform corrosion were also observed between the ceramic insulators and the metal coupons. When pitting corrosion occurred in these areas, the pits were deeper than the pits in areas without crevices. Crevice corrosion occurred most frequently in materials exposed to scrubbed, second flash steam and least frequently in materials exposed to wellhead fluid.

The following discussions summarize the findings for low alloy, iron-based materials, stainless steels, and nickel and titanium alloys.

Carbon and Low Alloy Steels

The low alloy, iron-based materials showed the poorest resistance to uniform and pitting corrosion in all process streams. Corrosion was more severe in the fluids than in the steams.

In several of the streams, the uniform corrosion rates of 1020 carbon steel and AISI 4130 obtained during the 1976/1977 field test were significantly different for each of two trials. In these cases, both rates are given in the tables. However, the corrosion rates for each sample of a given material in a given test were in agreement. Crevice corrosion occurred during the fifteen-day tests with 1020 steel in scrubbed, first flash steam and with 1020 steel and AISI 4130 in scrubbed, second flash steam. Otherwise, there was no crevice corrosion and stress corrosion cracking observed in the low alloy, iron-based materials during the 1976/1977 field test.

The reported pitting rates in the 1978 tests decrease with time. Comparisons of maximum pit depth (calculated from the reported rates) show that in most if not all cases, all of the pitting damage occurred within the first fifteen days with little or no subsequent attack. For all alloys, with the exception of AISI 4130, the range of pit depths for all streams was seven to 36 mils.

The widths of pits were four to five times greater than the depths. Pitting was generally more severe in scrubbed steam than in non-scrubbed steam.

Stainless Steels

Of the stainless steels, AISI 410 consistently showed the highest uniform corrosion rates (in some cases up to 50 times greater than the rates for the other stainless steels tested). The rates for Alloy 6X and Alloy 29-4 were the lowest, usually less than 1.0 mpy. AISI 430 generally showed very good resistance (less than 2 mpy) to uniform corrosion except in the wellhead fluid, where the rates were about ten times the rates for the other process streams. In two instances, AISI 316L and AISI 430 showed large differences in the rates observed for two separate trials. Both rates are recorded in the tables.

In general, uniform corrosion rates of most alloys did not vary significantly between the 15- and 30-day tests run in 1976/1977 and between the 15-, 30-, and 45-day tests run in 1978. AISI 430, however, usually showed poorer rates during the 30-day test in 1976/1977.

The 1976/1977 field test data indicated no pitting for Alloy 29-4 during either the 15-day or the 30-day test. The other stainless steels did pit, with Alloy 6X having the lowest rates (approximately 30 mpy). The data collected from the 1978 field test showed that pitting occurred in all stainless steels tested. Although Alloy 6X and Alloy 29-4 often had the lowest pitting rates, there were many cases where the lowest pitting rates occurred in the other alloys tested.

The reported pitting rates in the 1978 tests decrease with time. Comparisons of maximum pit depth (calculated from the reported rates) show that in most if not all cases, all of the pitting damage occurred within the first fifteen days with little or no subsequent attack. The range of pit depths for all alloys in this group in all streams was two to 22 mils.

Pit widths of those stainless steels which pitted in the 15-day tests during 1976/1977 were four to five times the pit depths.

Crevice corrosion occurred in most of the process streams with at least one of the stainless steels. AISI 316L showed evidence of crevice corrosion most often; this phenomenon occurred in all streams except first flash steam.

SCC occurred in AISI 316L in all streams. Severe intergranular corrosion of AISI 316L was noted in all cases. During the 30-day tests, transgranular corrosion was observed, with cracks completely perforating the AISI 316L samples. This occurred in all streams except the scrubbed steams, where transgranular corrosion took place without perforation.

Nickel-Based Alloys

All the nickel-based alloys tested had low uniform corrosion rates. The rates for most of the alloys in all streams were below 1.0 mpy. The highest rates occurred with Monel 400 and Monel 404. These rates were 5 to 10 times the rates measured for the other alloys in each process stream. Inconel 625, Hastelloy G, and Hastelloy S showed virtually no uniform corrosion in any process stream.

The uniform corrosion rates generally decreased slightly as the testing period increased (15-, 30-, or 45-days). However, since the rates are low, the change is probably not significant.

The 1976/1977 field test data indicate no pitting occurred in any of the nickel alloys tested. Pitting did occur, however, with all alloys tested during the 1978 field tests. The reported pitting rates in the 1978 tests decrease with time. Comparisons of maximum pit depth (calculated from the reported rates) show that in most if not all cases, all of the pitting damage occurred within the first fifteen days with little or no subsequent attack. The pit depths of all alloys in this group in all streams were less than 10 mils.

The only instances of crevice corrosion noted during the 1976/1977 field tests were Hastelloy G in 30-day tests of first flash fluid, first and second flash steam, and scrubbed second flash steam, and Hastelloy S in the 15-day and 30-day tests of scrubbed, second flash steam. No SCC was observed for the nickel-based alloys.

Titanium-Based Alloys

Uniform corrosion rates for titanium-based alloys during the 1976/1977 field test were less than 2 mpy in all cases. During the 1978 field test, uniform corrosion rates were below or equal to 0.1 mpy in all streams except wellhead fluid, where rates were 0 to 5 mpy.

Although no pitting occurred in 1976/1977 field tests, pitting was noted for all titanium alloys tested in the 1978 field test, with the exception of Ti-1.5 Ni, in at least one process stream. The pitting rates in most cases were less than 50 mpy.

There was no crevice corrosion or SCC observed for any of the titanium-based alloys.

4.19.2.3 Linear Polarization Measurements at the Bureau of Mines MTF

Method

The linear polarization technique was applied to in-situ corrosion measurements at the Bureau of Mines MTF. The measurements were made

using Magmax No. 1 fluid in three process streams: (1) the unflashed input brine, (2) the concentrated brine following two stages of stream separation, and (3) the steam condensate. The chemical analyses of these fluids are given in Table 4.19-42.

Linear polarization measurements were made with the portable Petrolite M-103E instrument using three identical electrodes. The working, counter, and reference electrodes were cylindrical, and all measurements were made with respect to the potential of the freely corroding electrode. The measured current was converted directly into a corrosion rate expressed in mils per year of surface thickness lost.

The electrochemical test package allowed the electrode assemblies to come in contact with the highly turbulent brine and condensate. The electrochemical package also isolated the probe and served as a vessel that allowed hot brine to circulate slowly through the probe chamber and around the electrodes. Air was removed from the electrode environment by a purge of the probe chamber and by brine circulation.

The electrodes were made of eight materials: 1020 carbon steel, AISI 316, AISI 430, Monel 400, Aluminum 6061, Inconel 625, Hastelloy C-276, and titanium. These metals and alloys were chosen because their compositions and corrosion resistances varied greatly. The electrode dimensions compensated for physical and chemical differences between the materials, so no further calibrations were required in order for direct measurements to be taken. Each set of electrodes was tested in the input brine. Additional measurements were made using 1020 carbon steel in the concentrated brine and steam condensate.

Results and Discussion

The linear polarization measurements were made with the probe in the retracted position and the electrodes exposed to brine that circulated slowly within the probe chamber. This procedure eliminated current fluctuations caused by disruptions of the scale depositions by the highly turbulent brine. The scale disruption problem was observed when the electrodes were fully inserted into the brine.

However, current instabilities were observed at periodic intervals with the probe in the fully retracted position. The fluctuations were due to pressure and flow-rate control valve operations. Pressure variations caused boiling and two-phase flow around the electrodes. In order to obtain consistent results, the gate valves on the electrochemical packages were closed before each measurement and reopened immediately afterward.

The results of the measurements are given in Table 4.19-43. The corrosion rates for 1020 carbon steel ranged from 12 mpy in the steam condensate to 145 mpy in the input brine. The corrosion rates of the

TABLE 4.19-42. -CHEMICAL ANALYSES OF THREE PROCESS STREAMS AT THE BUREAU
OF MINES MATERIALS TESTING FACILITY

FLUID CHARACTERISTIC		INPUT BRINE	CONCENTRATED BRINE ^a	STEAM CONDENSATE ^a
Temperature	°F	444	352	212
Pressure	psig	302	140	0
pH		5.1	5.7	6.7
Chloride (Cl)	ppm	118,200	128,000	8,620
Sodium (Na)	ppm	46,900	-	-
Calcium (Ca)	ppm	22,700	-	-
Potassium (K)	ppm	7,870	-	-
Manganese (Mn)	ppm	603	-	-
Strontium (Sr)	ppm	558	-	-
Iron (Fe)	ppm	477	-	-
Lithium (Li)	ppm	148	-	-
Lead (Pb)	ppm	36	-	-

^aDashes indicate no measurement taken

Source: Cramer and Needham 1978

TABLE 4.19-43. CORROSION RATES IN MAGMAMAX NO. 1 BRINE OBTAINED BY LINEAR POLARIZATION AND WEIGHT LOSS METHODS

MATERIAL TESTED	TEST ENVIRONMENT ^a	LINEAR POLARIZATION RESULTS (mpy)	WEIGHT-LOSS RESULTS ^b (mpy)
Aluminum 6061	Input brine	610	-
Monel 400	Input brine	62	-
AISI 316	Input brine	5.6	0.7
AISI 430	Input brine	3.1	0.6-2.2
Inconel 625	Input brine	0.8	0.0
Hastelloy C-276	Input brine	0.4	0.1
Titanium	Input brine	0.2	-
1020 Carbon Steel	Input brine	145	67
1020 Carbon Steel	Concentrated brine	62	48
1020 Carbon Steel	Steam condensate	12	-

^aFor chemical analyses of test environments, see Table 4.19-1

^bFifteen-day exposure

—: Corrosion rate not measured

SOURCE: Cramer and Needham 1978

materials tested in the input brine ranged from 0.2 mpy for titanium to 610 mpy for aluminum 6061, which was the only material to show observable, localized corrosion during the three-hour test exposures. Microscopic examinations showed that Aluminum 6061 had pitted severely.

Included in Table 4.19-43 are the results of a 15-day, in-situ weight-loss test that had been conducted at the same time. In all cases, these rates were substantially lower than the rates measured by the linear polarization technique. The test coupons were covered with a thick layer of scale which had a composition and other properties similar to the scale observed during linear polarization measurements.

The type of scale formed and the scale deposition rate strongly influenced the corrosion rates. This strong correlation suggests the declining corrosion rates occurred because scale growth reduced the area of metal exposed to the brine (Cramer and Needham 1978). Because the area of exposed metal is known only at the beginning of the test, the actual linear polarization corrosion rates were obtained by extrapolating time-dependent data to zero time exposure.

The corrosion rates for scale-free electrodes represent the upper limits for weight-loss corrosion results for coupons which undergo extended exposure. The corrosion rates of the weight-loss coupons could be considered time-averaged values of the instantaneous corrosion rates or, since scale deposition is a function of time, the area-averaged values (Cramer and Needham 1978). Thus, for extended exposures, the weight-loss corrosion rates would be equal to or less than the rates obtained by linear polarization, as can be seen in Table 4.19-43.

4.19.2.4 Tests by Lawrence Livermore Laboratory

Lawrence Livermore Laboratory (LLL) has shown that acidification of Magmamax No. 1 fluid to a pH less than 4.5 will prevent scale formation for a substantial period of time. The concentration of hydrochloric acid in the acidified fluid is about 200 ppm. LLL has done some materials testing in acidified geothermal fluid from well Magmamax No. 1, and preliminary results have been reported (Austin et al. 1977; Tardiff 1977).

The field tests were conducted using a mobile test bed which included a flash steam separator and had the capability of producing both pure brine or steam and two-phase mixtures. Test fluids were discharged through two-phase expander nozzles. There were provisions for modifying the test fluids by adding chemicals. The test equipment included simulated turbine cases and atmospheric pressure chambers containing static wear-blades.

The results of two series of tests are reported here. In one series, corrosion specimens were mounted on the base of the fixed wear-blades to test potential turbine materials for resistance to erosion,

pitting, crevice corrosion, and SCC. Specimens of the alloys were prepared by bending two strips of each alloy around a mandrel and retaining the sandwich under tension with a clamp. The specimens were mounted so that the broad face of the specimen was perpendicular to the expander nozzle discharge. The assemblies were exposed to acidified brine/steam mixtures at 212°F for periods varying from 7.5 to 110 hours. The nozzle discharge rate was 787 feet per second. Fluid pH varied from 2.5 to 4.5. The alloys tested and the test conditions are summarized in Table 4.19-44. Qualitative observations about the condition of the tensile face of the specimens exposed to spray impact are also given in the table. Pitting, cracking, and erosion were observed. Examination of the tensile face not exposed to spray impact showed that much of the pitting was a result of erosion-corrosion. There was no detectable erosion of the edge of the Ti-6Al-4V wearblades.

In the second series of tests, sixteen ferrous and nonferrous alloys were exposed to acidified nozzle exhaust effluent. Steam had been removed from wellhead fluid in the flash steam separator before discharge through the expander nozzles.

Corrosion rates were measured in an electrochemical cell in 16- to 20-hour tests using a Petrolite Instruments Co. corrosion rate meter. The meter employs a probe assembly with interchangeable electrodes fabricated from the test materials. The pH of the test fluid was in the range of 2.0 to 4.5, and the temperature was 187° to 208°F. Table 4.19-45 shows the measured uniform corrosion rates. The test method does not indicate susceptibility to pitting or other forms of local corrosion. The measured uniform corrosion rates indicate that some low alloy steels may be suitable for use in low-temperature streams, while stainless steels and nonferrous alloys might be applicable at higher temperatures.

4.19.2.5 Laboratory Tests by the Bureau of Mines

Two types of laboratory tests using synthetic fluids have been conducted (Cramer and Carter 1980; Carter and Cramer 1974). One series of tests was done in a high pressure autoclave at 450°F. The second series was done at atmospheric pressure at 221°F. Both series of tests used a solution made in the laboratory by dissolving metal chlorides, silicates, and metaborates in water and adjusting the pH to 6.1 with sodium hydroxide. The composition is defined in Table 4.19-46. The composition of the test solution is based on that of flashed fluid from Well IID 2.

450°F Autoclave Tests - Method

Twenty-three commercially available alloys were tested in the autoclave tests. Coupons, U-bend stress corrosion specimens, butt-welded samples, and specimens with fabricated crevices were exposed to 79 cubic inches of unstirred synthetic fluid contained in a 122 cubic inch, high

TABLE 4.19-44. RESULTS OF EROSION-CORROSION TESTS OF POSSIBLE TURBINE COMPONENT ALLOYS IN ACIDIFIED SALTON SEA GEOTHERMAL FLUID^a

MATERIAL TESTED	CONDITION	EXPOSURE (hrs)	AV. pH	EXPRESSED SAMPLE ^b CONDITION
4130 Steel	Quenched and tempered	7.5	2.7	Many pits up to 3 mils deep, several up to 9 mils deep
4130 Mo-modified steel	Quenched and tempered	7.5	2.7	Many pits up to 3 mils deep
2.25Cr-1Mo steel	Quenched and tempered	37	2.6	Severe pitting corrosion/erosion
Type 304	Mill annealed	37	2.9	Some pits ~0.2 - 0.4 mils deep
Type 316	Mill annealed	37	3.1	Many pits 0.6 - 2.0 mils deep
Type 410	Quenched and tempered	37	2.6	Severe pitting corrosion/erosion
18Cr-2Mo steel	Mill annealed	59.5	4.5	Some pits 0.1 - 0.2 mils deep
29Cr-4Mo steel	Mill annealed	59.5	4.5	Some cracks 0.4 - 0.6 mils deep
MP35N (cobalt based alloy)	40 percent cold rolled and aged at 1060°F for 4 hours	37	3.1	Many pits 0.6 - 2.0 mils deep
Ti-4Al-3Mo-1V	Mill annealed	22.5	3.7	Very few pits ~ 0.1 - 0.3 mils deep
Ti-8Al-1Mo-1V	Duplex milled and annealed	25	2.5	Many cracks 1.0 - 2.0 mils deep
Ti-6Al-4V	Mill annealed	25	2.5	Crack ~ 0.6 mils deep at base of pre-stress notch
Ti-6Al-4V	α-β annealed; water quenched stress relieved	110	2.9	Several cracks in notch ~ 0.1 mil deep. One crack 0.8 mil deep.
Ti-6Al-4V	α-β annealed, air cooled stress relieved	110	2.9	Several cracks in notch ~ 0.1 mil deep. One crack 0.8 mil deep
Ti-6Al-4V	α-β annealed, air cooled stress relieved	22.5	3.7	No cracks found

^aFluid was acidified Magmax No. 1 brine at ~ 212°F and 787 ft/s.

^bU-bend stress corrosion cracking specimens with tensile surface exposed to two-phase nozzle discharge

Source: Austin et al. 1977

TABLE 4.19-45. ELECTROCHEMICAL CORROSION RATES MEASURED IN ACIDIFIED FLASHED FLUID FROM WELL MAGMAMAX NO. 1 AT THE SALTON SEA KGRA^a

MATERIAL TESTED	UNIFORM CORROSION ^b (mpy)
<u>Ferrous Alloys</u>	
Carbon steel (AISI 1018)	100
1Cr-0.2Mo (Soo-90)	76
0Cr-0.5Mo (A-204 Grade B)	12
0.9Cr-0.5Mo (A-387 Grade 12)	14
2.2Cr-1Mo (A-387 Grade 64)	29
3.7Cr-8Mo (H-43)	15
5.6Cr-0.5Mo	8-23
9Cr-1Mo	20
Type 317 LM	0.3
Carpenter 20Cb3	0.5
E-Brite 26-1	1.0
29Cr-4Mo	1.5
29Cr-4Mo-2Ni	0.1
<u>Non-Ferrous Alloys</u>	
Ti-6Al-4V	0.1
Hastelloy C-276	0.06
Inconel 625	0.3

^a Acidified Magmamax No. 1 fluid with pH equals 2.0 to 4.5.
Temperature 187 to 208°F

^b Rates determined by electrochemical method during final two hours of 16 to 20 hour tests

SOURCES: Austin et al. 1977; Tardiff 1977

TABLE 4.19-46. COMPOSITION OF SYNTHETIC SALTON SEA FLUID USED IN LABORATORY TESTS

CONSTITUENT	CONCENTRATION (ppm) ^a		
	Nominal ^b	As Prepared ^c	After 15 days at 450°F
Sodium (Na)	53,000	59,250	68,250
Calcium (Ca)	28,000	22,400	19,350
Potassium (K)	16,500	16,700	13,150
Iron (Fe)	2,000	3.9	3.6
Manganese (Mn)	1,370	1,710	1,650
Zinc (Zn)	500	345	542
Strontium (Sr)	440	706	313
Silica (SiO ₂)	400	21	47
Boron (B)	390	200	-1
Barium (Ba)	250	294	344
Lithium (Li)	210	182	178
Lead (Pb)	80	14	69
Rubidium (Rb)	70	74	89
Cesium (Cs)	20	-	-
Magnesium (Mg)	10	27	4
Germanium (Ge)	-	-	-
Arsenic (As)	-	-	-
Aluminum (Al)	-	-	-
Chloride (Cl ⁻)	155,000	140,200	148,200
Sulfide (S ⁼)	30	34	<.1

^a-: Not measured

^bBased on the composition of unflashed fluid from well 11D No. 2, pH equals 6.4.

^cPrepared by dissolving reagent grade chlorides, sulfides, silicates, and metaborates in water and adjusting the pH to 6.1. Some constituents failed to dissolve or precipitated from solution at room temperature.

^dAfter prolonged heating, pH equals 5.0.

SOURCE: Cramer and Carter 1980

pressure, glass-lined stainless steel autoclave. The coupons and crevice specimens were suspended in the solution with glass supports, while the U-bend specimens rested on the bottom of the autoclave. Alloys were tested in separate exposures for periods of 15 to 30 days.

Test specimens were immersed in the test solution, the solution was vacuum degassed, and the autoclave was sealed and heated to 450°F ($\pm 3.6^\circ\text{F}$). The vapor pressure over the solution at these conditions was about 360 psig. In some tests, another gas was injected into the autoclave from a cylinder. Either oxygen, carbon dioxide, or methane was added until the pressure in the autoclave reached a specified value. The pressures of added gases were calculated based on Henry's Law of Constants so that a specific concentration of the gas would be dissolved in the solution at the test conditions. Tests were done with no added gases and with 100 ppm oxygen in the liquid, 250 ppm carbon dioxide, and 100 ppm methane.

After exposure the specimens were cleaned and examined microscopically. Uniform corrosion rates were determined by weight loss for both coupons and U-bend specimens. Pitting and crevice corrosion rates were calculated based on optical measurements of pit or crevice depth.

Weld-related corrosion failures were studied in deaerated and oxygenated fluid at 450°F. Weight-loss samples were butt-welded together following practices recommended by the American Society for Metals. The samples were not heat-treated to relieve stresses prior to corrosion testing.

450°F Autoclave Tests - Results and Discussion

The numerical corrosion rates measured in autoclave tests are summarized in Tables 4.19-47, 4.19-48, and 4.19-49. Table 4.19-47 shows test results of coupons, crevice specimens, and U-bend specimens in deaerated fluid and tests in which oxygen was added to the autoclave. Table 4.19-48 shows results obtained when carbon dioxide and methane were added. Results of tests of welded and nonwelded specimens are given in Table 4.19-49. Results are shown for both deaerated fluid and oxygenated fluid. The following discussion summarizes the findings for carbon steels, stainless steels, and nickel, titanium, copper, and molybdenum alloys.

Carbon and Low Alloy Steels

In deaerated fluid, the uniform corrosion rates of carbon and low alloy steels were less than 20 mpy. Carbon steel (AISI 1020) developed deep pits, while the other alloys were more resistant and suffered less

TABLE 4.19-47. CORROSION RATES MEASURED IN FIFTEEN-DAY AUTOCLAVE TESTS USING DEAERATED AND OXYGENATED SYNTHETIC SALTON SEA FLUID^a

MATERIAL TESTED	DEAERATED SOLUTION				SOLUTION CONTAINING 100 ppm OXYGEN			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
Iron Base								
Carbon Steel (AISI 1020)	16.5	67	N	2.2 N	1060	X ^f	N	-
AISI 4130	13.0	47	X ⁱ	10.3 N	1000	-	-	-
COR-TEN B	1.3 ^j	43	X ⁱ	-	1180	X ^f	N	-
Mariner	5.5	N ^j	N	-	1310	X ^f	N	-
AISI Type 316L	<0.05	N	X ^g	0.2 X	160	X ^f	X ⁱ	81 X
AISI Type 430	<0.05	N	X ^h	<0.05 X	345	X ^f	-	345 X
Sandvik 3RE60	2.1	N	X ^h	1.0 X	-	-	X ^{h,j}	-
E-Brite 26-1	0.1	N	N	0.1 N	20	955	X ⁱ	39.3 N
Carpenter 20	0.3	N	X ^h	0.3 X	-	-	-	-
Nickel Base								
Monel 400	19.7	X ^f	N ^h	12.0 N	290	X ^f	N	-
Inconel X-750	0.3	N	X ^h	0.4 N	-	-	-	-
Inconel 625	<0.05	N	X ^h	<0.05 X	19.2	530	X ⁱ	22.4 X
Hastelloy S	<0.05	N ^j	X ^g	<0.05 N	-	-	-	-
Hastelloy G	0.1	X ^j	X ^g	0.4 X	-	-	-	-
Hastelloy C-276	<0.05	N	N	0.1 N	5.9	640	X ⁱ	11.3 X
Copper Base								
70-30 Cupronickel	9.4	N	N	7.8 N	225	X ^f	X ⁱ	-
Titanium Base								
Titanium	0.3	215	X ⁱ	0.5 N	1.0	X ^f	N	0.1 X
Ti-1.7W	<0.05	N	X ^g	<0.05 N	-	-	-	-
Ti-1.5Ni	0.1	X ^f	X ^h	0.2 N	<0.05	N	N	<0.05 N
Ti-10V	<0.05	X ^f	X ^g	<0.05 N	-	-	-	-
Ti-0.2Pd	<0.05	X ^f	N	<0.05 N	<0.05	N	N	0.1 N
Ti60dc-12	<0.05	-	-	-	<0.05	N	N	-
Molybdenum Base								
TZM	1.6	N	N	0.8 N	-	-	-	-

^aT = 450°F, pres = 422.6 psia, chloride = 155,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dSpecimens with fabricated crevices

^eU-bend specimens (numerical data are general corrosion rates of U-bend specimens taken from Needham et al. 1977)

^fDepth not quantified

^g<1 mpy

^h>1 mpy but <5 mpy

ⁱ>5 mpy

^jSource: Needham, et al. 1977

KEY TO TABLE

N = indicated form of corrosion not detected

X = indicated form corrosion detected

- = no data available

Source: Cramer and Carter 1980 except as indicated

TABLE 4.19-48. CORROSION RATES MEASURED IN FIFTEEN-DAY AUTOCLAVE TESTS USING SYNTHETIC SALTON SEA FLUID WITH ADDITION OF CARBON DIOXIDE AND METHANE^a

MATERIAL TESTED	SOLUTION CONTAINING 250 ppm CARBON DIOXIDE				SOLUTION CONTAINING 100 ppm METHANE			
	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e	Uniform Corrosion ^b (mpy)	Pitting ^c (mpy)	Crevice Corrosion ^d	SCC ^e
Iron Base								
Carbon Steel (AISI 1020)	-	X ^f	N	-	1.8	X ^f	X ^g	2.1 N
AISI 4130	-	-	-	-	3.3	X ^f	X ^g	-
COR-TEN B	1.8	X ^f	N	-	0.4	X ^f	X ^g	-
Mariner	8.4	X ^f	X ^g	-	1.5	X ^f	X ^g	-
AISI Type 316L	0.2	N	N	<0.05 X	<0.05	N	N	<0.05 X
AISI Type 430	-	X ^f	-	0.3 X	<0.05	55 ^j	N	<0.05 X
Sandvik 3RE60	-	-	-	-	-	-	-	-
E-Brite 26-1	0.2	X ^f	N	<0.05 N	<0.05	30	N	<0.05 N
Carpenter 20	-	-	-	-	-	-	-	-
Nickel Base								
Monel 400	0.1	X ^f	N	-	<0.05	X ^f	N	3.4 N
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	0.1	N	N	<0.05 N	0.1	N	N	<0.05 N
Hastelloy S	-	-	-	-	-	-	-	-
Hastelloy G	-	-	-	-	-	-	-	-
Hastelloy C-276	-	N	-	<0.05 N	<0.05	N	X ^g	<0.05 N
Copper Base								
70-30 Cupronickel	1.0	X ^f	N	-	1.0	X ^f	N	-
Titanium Base								
Titanium	<0.05	N	N	0.5 N	<0.05	X ^f	X ^g	<0.05 N
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5N1	-	-	-	-	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	<0.05	N	X ^g	0.05 N	<0.05	X ^f	N	<0.05 N
TiCode-12	-	N	N	-	<0.05	N	N	<0.05 N
Molybdenum Base								
TZM	-	-	-	-	-	-	-	-

^aT = 450°F, pres = 422.6 psia, chloride = 155,000 ppm

^bBased on weight loss

^cBased on maximum pit depth

^dSpecimens with fabricated crevices

^eU-bend specimens (numerical data are general corrosion rates of U-bend specimens taken from Needham, et al. 1977)

^fRate not given

^g<1 mpy

^h>1 mpy but <5 mpy

ⁱ>5 mpy

^jSource: Needham, et al. 1977

KEY TO TABLE

N = indicated form of corrosion not detected

X = indicated form of corrosion detected

- = no data available

Source: Cramer and Carter 1980 except as indicated

TABLE 4.19-49. RESULTS OF LABORATORY TESTS OF THE EFFECT OF WELDING ON UNIFORM CORROSION RATE IN SYNTHETIC SALTON SEA FLUID^a

MATERIAL TESTED	WELDING TECHNIQUE ^b	UNIFORM CORROSION RATE IN DEAERATED SOLUTION (mpy)		UNIFORM CORROSION RATE IN SOLUTION CONTAINING 100 ppm OXYGEN (mpy)	
		Butt-Welded Samples	Non-Welded Samples	Welded Samples	Non-Welded Samples
1020 carbon steel	Stick	48.2	4.8	1180	1160
4130 steel	Stick	36.3	3.8	1120	1001
316 L stainless steel	Tig	0.2 ^c	<0.05	145 ^c	245
E-Brite	Tig	<0.05	0.1	145	21
Titanium	Tig	0.1	0.3	0.1	<0.05
Ti-0.2% Pd	Tig	0.3	<0.05	0.2	<0.05
Inconel 625	Tig	0.1	<0.05	87	19

^aTests were done in a high-pressure autoclave at 450°F using synthetic fluid of the composition in Table 4.19-46.

^bStick - shielded metal-arc welding
Tig - inert gas tungsten-arc welding

^cStress corrosion cracking was observed.

SOURCE: Cramer and Carter 1980

attack. Crevice corrosion was severe. Only AISI 1020 and 4130 were tested for SCC. Both were resistant, but the weight loss of the AISI 4130 coupon increased threefold. In the case of 1020 carbon steel and 4130 steel, welding increased the uniform corrosion rate tenfold in the deaerated fluid.

The addition of oxygen increased uniform corrosion of low alloy steels approximately 1000 times. There were no differences in weight loss for the welded and nonwelded samples of 1020 and 4130 steel in tests when oxygen was added.

Stainless Steels

In nonaerated fluid, stainless steels had uniform corrosion rates of less than 2 mpy. Some were subject to slight or moderate crevice corrosion though no pitting was observed. Only E-Brite 26-1 was resistant to SCC. Welding caused a slight increase in weight loss, and SCC was noted in welded AISI 316L specimens.

Addition of oxygen caused severe increases in general corrosion, pitting, and crevice attack. Intergranular corrosion of AISI 316L was observed. Oxygen increased severity of stress corrosion cracking in all alloys except E-Brite 26-1. Welding of E-Brite 26-1 caused a sevenfold increase in weight loss.

Carbon dioxide addition caused slight increases in the severity of uniform corrosion and pitting but did not affect the rate of localized corrosion.

Methane addition caused a severe increase in pitting and slight reductions in uniform corrosion.

Nickel-Based Alloys

Monel 400 showed a uniform corrosion rate of about 20 mpy in nonaerated fluid, as well as pitting of undefined depth. It did resist crevice corrosion and SCC. In nonaerated fluid, the uniform corrosion rates of the other nickel alloys were less than 2 mpy. Pitting was light or did not occur. Inconel 625, Hastelloy S, and Hastelloy G showed significant crevice corrosion and displayed SCC. In the nonaerated fluid, welding had little effect on the corrosion rate of Inconel 625, the only nickel alloy tested in the welded condition.

Aeration (with 100 ppm oxygen) caused at least hundred-fold increases in the uniform corrosion rates of Monel 400 (290 mpy), Inconel 625 (19 mpy) and Hastelloy C-276 (6 mpy); the only nickel alloys tested in this environment. Pitting of Monel 400 occurred but was not quantified. Inconel 625 and Hastelloy C-276 showed pitting in excess of 500 mpy with

severe crevice corrosion and SCC. The weight loss of welded Inconel 625 was four times that of nonwelded specimens.

The addition of carbon dioxide had little effect on Inconel 625 and Hastelloy C-276, while methane caused increased crevice corrosion.

Titanium-Based Alloys

In nonaerated fluid, all the titanium alloys had uniform corrosion rates of less than 0.5 mpy. Severe pitting and crevice corrosion occurred in commercially pure titanium. The rate of crevice corrosion for Ti-1.5Ni was between 1 and 5 mpy. None of the other titanium alloys were susceptible to pitting or crevice corrosion. No SCC was observed, and welding of Ti-0.2Pd had little effect on weight loss.

Commercially pure titanium showed SCC, but the test performance of titanium alloys improved when oxygen was added. Uniform corrosion rates of the alloys were less than 0.05 mpy, and no local corrosion or SCC was observed. Welding had little effect on weight loss of Ti-0.2Pd. Additions of carbon dioxide and methane produced results similar to those when oxygen was added.

Copper-Based Alloy

The alloy, 70-30 cupronickel, was fairly resistant to all modes of corrosion in nonaerated fluid and fluids containing methane and carbon dioxide. Addition of oxygen caused a severe increase in the rate of uniform corrosion as well as pitting and crevice corrosion. Addition of hydrogen sulfide to any of these environments could cause more severe corrosion.

Molybdenum Alloy

TZM was tested only in nonaerated fluid. It was resistant to all modes of corrosion.

221°F Laboratory Test - Methods

Another series of tests using the synthetic Salton Sea fluid (described in Table 4.19-16) was done at atmospheric pressure and at the boiling point of the fluid (221°F). Tests were done in 0.23 gallon Erlenmeyer flasks fitted with a sparger (bubbler) and a water-cooled condenser. Coupons and specimens with fabricated crevices were suspended in the boiling test solution. U-bend specimens lay on the bottom of the flask. In some tests the solution was deaerated with a continuous helium purge; in the other series the fluid was aerated by continuous air purge. Tests were conducted for 15-day periods. Duplicate samples of each material were tested, and each test was done in a separate flask.

The coupons and U-bend specimens were cleaned after exposure, and the uniform corrosion rate was determined by weight loss. Specimens were examined microscopically for pits, cracks, and crevice corrosion.

221° Laboratory Tests - Results and Discussion

Corrosion rates calculated from 15-day weight loss and maximum pit or crevice depth are given in Table 4.19-50. The following observations about the performance of ferrous, nickel, copper, titanium, aluminum and molybdenum alloys are based on the corrosion rates summarized in Table 4.19-50.

Iron-Based Alloys

All ferrous alloys except AISI 1020 carbon steel had uniform corrosion rates of less than 0.05 mpy in nonaerated fluid. Uniform corrosion rates for these alloys increased in aerated fluid, though all were less than 5 mpy.

Pitting was not observed in either aerated or nonaerated fluid. AISI 316L, Sandvik 3RE60, and Carpenter 20 showed slight (less than 0.1 mpy) crevice attack in nonaerated fluid. Crevice corrosion rates in aerated fluid were greater than 50 mpy. SCC was not observed in tests with either aerated or deaerated fluids.

Nickel-Based Alloys

Inconel 625, Hastelloy S, Hastelloy G, Hastelloy C-276, and Inconel X-750 had uniform corrosion rates less than 0.05 mpy in deaerated fluid. Monel 400 was less resistant (2.8 mpy). Aeration greatly increased the corrosion of Inconel X-750. The uniform corrosion rates of the other nickel-based alloys were not significantly affected by aeration.

No pitting or SCC was observed in either environment. Both Monel 400 and Inconel X-750 experienced some crevice corrosion in nonaerated media. Only Inconel 625 and Hastelloy C-276 did not suffer crevice attack in aerated fluid.

Copper-Based Alloys

Copper and Cu-2Fe alloy were fairly resistant to uniform corrosion in nonaerated media. Aeration increased uniform corrosion rates by a factor of four. No pitting or crevice corrosion was observed in either fluid.

70-30 cupronickel was more resistant than other copper-based alloys to uniform corrosion (0.6 mpy) in nonaerated fluid, but aeration caused a tenfold increase in the uniform corrosion rate. It was subject to crevice corrosion in both fluids.

TABLE 4.19-50. CORROSION RATES MEASURED IN FIFTEEN-DAY LABORATORY TESTS AT 221°F USING DEAERATED AND AERATED SYNTHETIC SALTON SEA FLUIDS

MATERIAL TESTED	DEAERATED FLUID				AERATED FLUID			
	Uniform Corrosion ^a (mpy)	Pitting ^b (mpy)	Crevice Corrosion	SCC ^c	Uniform Corrosion ^a (mpy)	Pitting ^b (mpy)	Crevice Corrosion	SCC ^c
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	4.2	N	-	N	5.8	N	-	N
AISI Type 316L	<0.05	N	X ^d	N	4.0	N	X ^h	N
Sandvik 3RE60	<0.05	N	X ^d	N	0.9	N	X ^h	N
Carpenter 20	<0.05	N	X ^d	N	2.2	N	X ^g	N
E-Brite 26-1	<0.05	N	N	N	3.6	N	N	N
<u>Nickel Base</u>								
Monel 400	2.8	N	X ^f	N	3.7	N	X ^g	N
Inconel X-750	<0.05	N	X ^e	N	3.4	N	X ^g	N
Inconel 625	<0.05	N	N	N	<0.05	N	N ^f	N
Hastelloy S	<0.05	N	N	N	<0.05	N	X ^f	N
Hastelloy G	<0.05	N	N	N	0.1	N	X ^f	N
Hastelloy C-276	<0.05	N	N	N	<0.05	N	N	N
<u>Copper Base</u>								
Copper	3.1	N	N	N	12.5	N	N	N
Cu-2Fe	2.7	N	-	N	13.3	N	-	N
70-30 Cupronickel	0.6	N	X ^e	N	5.8	N	X ^f	N
<u>Titanium Base</u>								
Titanium	<0.05	N	N	N	<0.05	N	X ^d	N
Ti-1.7W	<0.05	N	N	N	<0.05	N	N	N
Ti-1.3Ni	<0.05	N	N	N	<0.05	N	N	N
Ti-10V	<0.05	N	N	N	<0.05	N	N	N
<u>Aluminum Base</u>								
2024-T3	1.3	>1400	X ^h	N	34.9	N	X ^h	N ⁱ
6061-T6	30.4	>1400	N	N	56.6	N	N	N ⁱ
<u>Molybdenum Base</u>								
TZM	<0.05	N	N	N	1.4	N	X ^g	N

^aBased on weight loss after 15 days

^bBased on maximum pit depth

^cU-bend specimens

^d<0.1 mpy

^e>0.1 mpy but <1 mpy

^f>1 mpy but <5 mpy

^g>5 mpy but <50 mpy

^h>50 mpy.

ⁱTen-fold increase in general corrosion, concentrated in bend areas

Sources: Cramer and Carter 1980; Carter and Cramer 1974

These tests were in hydrogen sulfide-free fluid. Experience has shown that copper-based alloys, especially cupronickels, are severely attacked in fluids containing hydrogen sulfide (Miller 1977).

Titanium-Based Alloys

All four titanium alloys were resistant to uniform corrosion, pitting, and SCC in both aerated and deaerated fluid. Commercially pure titanium showed less than 0.1 mpy crevice corrosion in aerated fluid. No other crevice corrosion was observed.

Aluminum-Based Alloys

These alloys are not suitable for exposure to Salton Sea geothermal fluids. Both 2024 and 6061 alloys pitted badly in nonaerated fluid. The pitting rate, calculated from pit depth after 15 days, was greater than 1400 mpy. Crevice corrosion of 2024T-T3 was severe (greater than 50 mpy). A tenfold increase in the uniform corrosion rate in the stressed area of the U-bend specimens was noted in tests with aerated fluid, though no cracks were observed.

Molybdenum-Based Alloy

TZM was the only molybdenum-based alloy tested. Uniform corrosion was very slight (less than 0.05 mpy) in deaerated fluid; no local corrosion or stress corrosion cracking was detected. Aeration increased uniform corrosion to 1.4 mpy and significant crevice corrosion (greater than 5 mpy but less than 50 mpy) occurred. No SCC was observed.

4.19.2.6 Tests at the Bureau of Mines MTF Using Nonmetallic Materials

Two series of tests have been conducted at the Bureau of Mines MTF at the Salton Sea KGRA using polymer cements. See Section 5.1 for more information.

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4.20 THE GEYSERS, CALIFORNIA

The largest geothermal electric complex in the world is located at The Geysers in Sonoma County, California. The present capacity of this site exceeds 2000 MW. The location of The Geysers is shown in Figure 4.20-1.

Approximately 175 wells tap the vapor-dominated resource. Typical shut-in pressure is about 475 psig with a corresponding temperature of 482°F. Specific enthalpy is around 1204 Btu/lb. A typical well produces 2,000,000 lb/hr of steam at 125 psig. Fifteen wells are required for a typical 115 MW unit (DiPippo 1979).

The turbines at The Geysers are made from conventional materials except that AISI 403 (12Cr) blades are used. In the first twelve units, the steam is condensed in direct contact condensers, and the resulting condensate is pumped from the condenser and incorporated into the cooling water. Wet cooling towers are used. Hydrogen sulfide emission from Units 1-12 is abated using the ferric sulfate method (ferric ions oxidize hydrogen sulfide to elemental sulfur).

Future units are to use tube-and-shell surface contact condensers with the Stretford process for hydrogen sulfide abatement. Table 4.20-1 presents a history of plant development at The Geysers.

4.20.1 Fluid Chemistry

The steam produced at The Geysers is slightly (not quantified) superheated at the well head. Analysis of the noncondensable gases in the steam is presented in Table 4.20-2. Table 4.20-2 also gives the composition of condensate/cooling water at The Geysers. The steam condensate is used as cooling water. The concentrations of the ionic species in the cooling water are about six times what would be observed in steam condensate.

4.20.2 Corrosion Tests

Two corrosion studies have been performed at The Geysers. One study determined the effect of ferric sulfate (added to abate hydrogen sulfide emission by oxidizing hydrogen sulfide to elemental sulfur). This study is discussed in section 4.20.2.1. Results are summarized in Table 4.20-3.

A second study of the effect of different heat treatments on corrosion-fatigue of turbine blade alloys is discussed in section 4.20.2.2.

FIGURE 4.20-1. LOCATION OF THE GEYSERS GEOTHERMAL RESOURCE

TABLE 4.20-1. PG&E PLANT DEVELOPMENT AT THE GEYSERS, CALIFORNIA

UNIT NO.	CAPACITY MW	YEAR OF START-UP	TURBINE MANUFACTURER	CONDENSER TYPE	HYDROGEN SULFIDE ABATEMENT METHOD
1	11	1960	G.E.	DC ^a	Ferric ion
2	13	1963	Elliot	DC	Ferric ion
3	27	1967	Elliot	DC	Ferric ion
4	27	1968	Elliot	DC	Ferric ion
5	53	1971	Toshiba	DC	Ferric ion
6	53	1971	Toshiba	DC	Ferric ion
7	53	1972	Toshiba	DC	Ferric ion
8	53	1972	Toshiba	DC	Ferric ion
9	53	1973	Toshiba	DC	Ferric ion
10	53	1973	Toshiba	DC	Ferric ion
11	106	1976	Toshiba	DC	Ferric ion
12	106	1979	Toshiba	DC	Ferric ion
13	135	1980 ^c	G.E.	SC ^b	Stretford
14	110	1980 ^c	Toshiba	SC	Stretford
15	55	1979	G.E.	SC	Stretford
16	110	Future	Toshiba	SC	Stretford
17	110	1982 ^c	Toshiba	SC	Stretford

^aDirect contact^bSurface contact, tube-and-shell^cPlanned

Source: DiPippo 1979

TABLE 4.20-2. COMPOSITION OF UNIT 7 GEYSERS STEAM AND CONDENSATE

<u>STEAM</u>	
<u>Species</u>	<u>ppm (wt)</u>
Carbon dioxide (CO ₂)	2200
Hydrogen (H ₂)	70
Hydrogen sulfide (H ₂ S)	220
Methane (CH ₄)	60
Nitrogen (N ₂)	18
Ammonia (NH ₃)	400
<u>CONDENSATE</u>	
Phenolphthalein alkalinity (as calcium carbonate)	128
Total alkalinity (as calcium carbonate)	482
Sulfur compounds (as sulfate)	229
Chloride (Cl ⁻)	<1.0
Boron (B)	27
Nitrate (as nitrogen (N))	<0.1
Silica (SiO ₂)	1.5
Calcium (Ca ⁺²)	<1
Magnesium (Mg ⁺²)	<1
Calcium and Magnesium Hardness (as calcium carbonate)	3
Dissolved solids by evaporation at 220°F	111
Organics and volatiles at 590°F	51
<u>Suspended Matter</u>	
Total suspended matter (at 220°F)	358
Fixed suspended matter (at 1022°F)	280
Volatile suspended matter (at 1022°F)	78

Source: Ivy and Friedrich 1979

TABLE 4.20-3. THE GEYSERS COOLING WATER CORROSION SCREENING TABLE

MATERIAL TESTED	AERATED CONDENSATE WITHOUT FERRIC SULFATE				AERATED CONDENSATE WITH FERRIC SULFATE			
	UNIFORM CORROSION	PITTING	CREVICE CORROSION	SCC	UNIFORM CORROSION	PITTING	CREVICE CORROSION	SCC
<u>Iron Base</u>								
AISI 1010	C	-	-	-	-	-	-	-
Gray Iron	B	-	-	-	D	-	-	-
3% Ni Gray Iron	B	-	-	-	-	-	-	-
Ductile Iron	C	X	-	-	D	-	-	-
Type-2 Ni-Resist	C	X	X	-	B	-	-	-
Cor-Ten	-	-	-	-	C	-	-	-
AISI T304	A	X	X	-	A	X	-	-
AISI T304 (sensitized)	A	X	X	-	B	X	X	-
AISI T316	A	H	H	-	A	-	-	-
AISI T316 (sensitized)	A	X	X	-	A	X	X	-
AISI T409	A	X	X	-	-	-	-	-
AISI T410	A	X	X	-	B	X	X	-
AISI T430	A	X	X	-	B	X	X	-
Carpenter 20Cb3	A	H	X	-	A	-	-	-
17-4 PH	A	X	X	-	A	-	-	-
CF-8	A	H	X	-	-	-	-	-
CF-8M	A	H	H	-	-	-	-	-
<u>Copper Base</u>								
Admiralty Brass	-	-	-	-	C	-	-	-
90-10 Cu-Ni	-	-	-	-	C	-	-	-
10Al-5Ni Bronze	A	-	-	-	-	-	-	-
85-5-5-5 Bronze	A	-	-	-	-	-	-	-
<u>Aluminum Base</u>								
Alcoa 1100	-	-	-	-	A	X	X	-
Alcoa 2024	A	X	X	-	C	X	X	-
Alcoa 3003	-	-	-	-	B	X	X	-
Alcoa 6061	A	X	X	-	B	X	X	-
<u>Nickel Base</u>								
Monel 400	B	-	-	-	B	X	X	-

Key to Table

- A - general corrosion rate <1 mpy
 B - general corrosion rate >1 mpy but <10 mpy
 C - general corrosion rate >10 mpy but <50 mpy
 D - general corrosion rate >50 mpy
 H - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 - - no data available

Source: Dodd and Ham 1973

4.20.2.1 Corrosion Test in Cooling Water System

Test Methods and Conditions

In order to evaluate the effect of hydrogen sulfide abatement with ferric sulfate, long-term corrosion tests of several alloys were begun in 1972. Sets of 2-1/4-inch diameter, non-stressed metal coupons were mounted one-fourth inch apart on an insulated center pin. Sets were placed near the top of the barometric condensers of Units 1 and 2, where they were exposed to a wash-mist of aerated cooling water/condensate mixture. Other sets were placed in the hot wells of Units 1 and 2, where they were covered with aerated condensate. The test media of both Units 1 and 2 were similar in the amount of hydrogen sulfide, carbon dioxide, ammonia, and trace chloride present. The media in Unit 2 also contained approximately 33 ppm iron as ferric sulfate for the abatement of hydrogen sulfide emission. Uniform corrosion was measured by weight loss. The growth rate of the deepest pit was calculated from the measured depth of the deepest pit at the end of the test period; the crevice growth rate was calculated in the same way. A crevice was formed between the coupon and the insulating spacer (Dodd and Ham 1976). Exposure times for coupons in submerged cooling water/condensate were 590 days and 585 days without and with ferric sulfate, respectively. The specimens were exposed to spray without sulfate for 586 days and to spray with sulfate for 1378 days. (Dodd and Ham 1976).

Results and Discussion

The results of this study are presented in Table 4.20-4 and Table 4.20-5. Table 4.20-4 compares the corrosive behavior of materials exposed to aerated water/condensate spray with and without ferric sulfate addition. Table 4.20-5 makes similar comparisons for materials submerged in the condensate/cooling water. The results are discussed below.

Cast Irons

Gray cast iron had uniform corrosion rates of 8 mpy in condensate and 4 mpy in spray without ferric sulfate. No pitting or crevice corrosion was reported. Addition of ferric sulfate caused greater than tenfold increases in weight loss. In all the environments, the mode of failure was graphitization (the matrix dissolved, leaving a weak, graphite skeleton).

The 3-percent nickel cast iron was not exposed to the liquid cooling water/condensate. In the spray without ferric sulfate, it was graphitized at a corrosion rate of less than 3.8 mpy. It was not tested in spray with ferric sulfate.

Ductile cast iron was severely pitted (penetration rate was 26.5 mpy) with broad pits in the cooling water/condensate spray. Uniform corrosion was less severe (less than 5.8 mpy). The uniform corrosion rate of

TABLE 4.20-4. CORROSION STUDY IN THE AERATED COOLING WATER SPRAY AT THE GEYSERS, CA.

MATERIAL USED	WITHOUT FERRIC SULFATE ADDITION ^a				WITH FERRIC SULFATE ADDITION ^b			
	Uniform Corrosion (mpy)	Pitting (Growth of deepest pit in mpy)	Crevice Corrosion (mpy)	SCC	Uniform Corrosion (mpy)	Pitting (Growth of deepest pit in mpy)	Crevice Corrosion (mpy)	SCC
<u>Low Alloy Iron Base</u>								
Mild steel (1010)	>6.2 ^c	-	-	-	-	-	-	-
Gray iron	<3.6 ^d	-	-	-	>73 ^d	-	-	-
3% gray iron	<3.8 ^d	-	-	-	-	-	-	-
Ductile iron	<5.8	26.5 ^e	-	-	>78 ^d	-	-	-
Type 2 Ni-resist	<2.7	4.0 ^e	-	-	>5 ^d	-	-	-
Cor-Ten	-	-	-	-	-	-	-	-
<u>Stainless Steels</u>								
AISI 304	<0.1	1.1	N	-	>10.8	-	-	-
AISI 304 (sensitized)	<0.1	3.2	1.1	-	0.3	-	-	-
AISI 316	<0.1	N	N	-	1.4	-	-	-
AISI 316 (sensitized)	<0.1	0.3	1.9	-	<0.1	-	-	-
AISI 409	<0.1	5.3	3.7	-	<0.1	6.9 ^f	3.1	-
AISI 410	<0.1	9.5	X ^g	-	-	-	-	-
AISI 430	<1.0	X ^h	X ^g	-	2.4	738 ^h	X ^g	-
Carpenter 20Cb3	<0.1	N	N	-	2.2	30.5	X ^g	-
17-4PH	<0.1	1.6	N	-	<0.1	-	-	-
CF-8 (cast)	<0.1	N	1.1	-	0.1	-	-	-
CF-8M (cast)	<0.1	N	N	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	<5	-	-	-	1.6	-	-	-
<u>Aluminum Base</u>								
Alcoa 1100	-	-	-	-	0.9	12.5 ^e	6.2	-
Alcoa 2024	<0.4	6.6	X ^g	-	15	>31 ^{e,h}	11.8	-
Alcoa 3003	-	-	-	-	1.3	19.9 ^e	8.7	-
Alcoa 6061	<0.1	1.32	4.0	-	5.5	18.7 ^e	7.5	-
<u>Copper Base</u>								
90-10 CuNi	-	-	-	-	14.4	-	-	-
Admiralty Brass	-	-	-	-	19	24.3	13.7	-
10Al-5Ni Bronze	<1.8	-	-	-	-	-	-	-
85-5-5-5 Bronze	<1.6 ⁱ	-	-	-	-	-	-	-

^aExposure 586 days^bExposure 1378 days^cSpecimen gone^dGraphitized, matrix destroyed^eBroad pit attack^fEdge pitting^gCrevice perforated sample^hNumerous perforationsⁱGeneral attack

KEY TO TABLE:

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected but not quantified

- - No data available

SOURCE: Dodd and Ham 1975

TABLE 4.20-5. CORROSION STUDY IN THE COOLING WATER/CONDENSATE AT THE GEYSERS, CA.

MATERIAL TESTED	WITHOUT FERRIC SULFATE ADDITION ^a				WITH FERRIC SULFATE ADDITION ^b			
	Uniform Corrosion (mpy)	Pitting (Growth of deepest pit in mpy)	Crevice Corrosion (mpy)	SCC	Uniform Corrosion (mpy)	Pitting (Growth of deepest pit in mpy)	Crevice Corrosion (mpy)	SCC
<u>Low Alloy Iron Base</u>								
Mild steel (1010)	>14.3	-	-	-	-	-	-	-
Gray iron	8.0	-	-	-	>78 ^{c,d}	-	-	-
3% Ni gray iron	8.4	-	-	-	-	-	-	-
Ductile iron	14.3	-	-	-	>73 ^{c,d}	-	-	-
Type 2 Ni-resist	0.9	5.6	4.3	-	> 7.6 ^c	-	-	-
Cor-Ten	-	-	-	-	16.8	-	-	-
<u>Stainless Steels</u>								
AISI 304	< 0.1	-	X ^e	-	0.7	9.3 ^f	-	-
AISI 304 (sensitized)	-	-	-	-	0.9	15.5 ^f	3.1	-
AISI 316	< 0.1	-	-	-	< 0.1	-	-	-
AISI 316 (sensitized)	-	-	-	-	< 0.1	3.7	-	-
AISI 409	0.2	27.8 ^g	27.8	-	-	-	-	-
AISI 410	0.1	22.3 ^g	5.6	-	3.4	> 40 ^g	3.7	-
AISI 430	0.3	19.2 ^g	19.2	-	3.5	> 40 ^g	0.6	-
Carpenter 20Cb3	0.1	-	X ^e	-	0.1	-	-	-
17-4PH	-	-	-	-	< 0.1	-	-	-
CF-8 (cast)	< 0.1	-	4.9	-	-	-	-	-
CF-8M (cast)	< 0.1	-	-	-	-	-	-	-
<u>Nickel Base</u>								
Monel 400	2.1	-	-	-	0.4	4.9	X ^e	-
<u>Aluminum Base</u>								
Alcoa 1100	-	-	-	-	0.8	15.5 ^h	3.7	-
Alcoa 2024	-	-	-	-	0.6	27.2 ^h	5.6	-
Alcoa 3003	-	-	-	-	0.8	5.6 ^h	8.0	-
Alcoa 6061	0.1	11.1	10.5	-	0.9	10.5 ^h	4.3	-
<u>Copper Base</u>								
Admiralty Brass	-	-	-	-	-	-	-	-
90-10 CuNi	-	-	-	-	-	-	-	-
10Al-5Ni Bronze	0.1	-	3.7	-	-	-	-	-
85-5-5-5 Bronze	-	-	-	-	-	-	-	-

^aExposure: 590 days^bExposure: 585 days^cGraphitization^dMatrix destroyed^eIncipient^fExtensive pitting^gPerforated^hBroad pit attack

KEY TO TABLE:

N - Indicated form of corrosion not detected

X - Indicated form of corrosion detected but not quantified

- - No data available

Source: Dodd and Ham 1976

specimens submerged in the hot well was about threefold greater, but no pitting was reported.

Addition of ferric sulfate increased uniform corrosion of ductile cast iron to greater than 78 mpy in both liquid and spray. The matrix was destroyed. No pitting or crevice corrosion was reported.

Type 2 Ni-resist was the most resistant iron alloy tested. In spray without ferric sulfate, the uniform corrosion rate was less than 3 mpy, though crevice corrosion occurred at about 4 mpy. Uniform corrosion in the liquid was lower (approximately 1 mpy), but pitting and crevice corrosion occurred at about 5 mpy. The material was graphitized in both spray and liquid with ferric sulfate addition.

Carbon and Low Alloy Steel

Carbon steel (AISI 1010) was exposed only to spray and liquid without ferric sulfate. The specimen in the liquid corroded at more than 15 mpy, while the coupon in the spray was completely destroyed prior to the end of the 586-day exposure.

Cor-Ten was tested only in cooling water/condensate with ferric sulfate. The uniform corrosion rate in liquid was about 17 mpy. Broad depressions formed. In spray, the rate was greater than 11 mpy.

Stainless Steels

In both spray and liquid without ferric sulfate, the uniform corrosion rate of AISI 304 was less than 0.1 mpy. Incipient crevice attack occurred in submerged specimens, while pitting at about 1.1 mpy occurred on coupons exposed to spray.

Addition of ferric sulfate caused uniform corrosion rates of about 0.3 mpy in spray, without pitting or crevice corrosion of the AISI 304. In the liquid, the uniform attack was about 1 mpy, but pitting at 9 mpy was reported. The corrosion rate of AISI 304 increased significantly (not quantified) with time.

CF-8, the cast equivalent of AISI 304, gave results similar to AISI 304 except that crevice corrosion was more severe, as shown in Tables 4.20-4 and 4.20-5.

In spray without ferric sulfate, the uniform corrosion rate of AISI 316 was less than 0.1 mpy with no pitting or crevice attack. CF-8M (cast T316) gave the same result. Sensitization of AISI 316 caused crevice attack (1.9 mpy) and pitting (0.3 mpy). Addition of ferric sulfate to the spray did not affect the corrosion of AISI 316. CF-8M was not tested in

this environment. Sensitization of AISI 316 caused more serious pitting (7 mpy) and crevice corrosion (3.1 mpy). The pitting occurred on the edges of the coupon.

In the liquid phase without ferric sulfate, the uniform corrosion rates of CF-8M and AISI 316 were less than 1 mpy. No pitting or crevice corrosion was reported. Sensitized AISI 316 was not tested. Addition of ferric sulfate did not produce any reported change in corrosion of AISI 316. Sensitized AISI 316 pitted at 3.7 mpy.

AISI 409, 410, and 430 gave similar performances in both spray and liquid without ferric sulfate. Uniform corrosion rates were less than 1 mpy, but many perforations of the coupons occurred. Addition of ferric sulfate increased the uniform corrosion rate to 2 to 4 mpy. The corrosion rate of AISI 430 increased with time (magnitude not quantified). From the data shown in Tables 4.20-4 and 4.20-5, it is not possible to say whether ferric sulfate increased the severity of localized corrosion.

Carpenter 20Cb3 alloy appears equivalent to T316 in each environment where it was tested.

17-4PH was not tested in the liquid phase condensate/cooling water without ferric sulfate. In the spray, the uniform corrosion rate was less than 0.1 mpy with no crevice attack. Pitting rate was 1.6 mpy.

Aluminum-Based Alloys

These alloys were very susceptible to pitting in all environments where they were tested. Details are available in Tables 4.20-4 and 2.40-5.

Copper-Based Alloys

90-10 cupronickel was tested only in spray with ferric sulfate addition. Uniform corrosion was 14.4 mpy and no pitting or crevice attack was reported.

Admiralty brass was exposed to spray with ferric sulfate. Uniform corrosion was high (19 mpy) with severe pitting (24.3 mpy) and crevice corrosion (13.7 mpy).

10Al-5Ni bronze had less than 2 mpy uniform corrosion in spray and in condensate without ferric sulfate. Crevice attack (3.7 mpy) was reported in the liquid phase. No localized attack in spray was reported. This alloy was not tested in environments with ferric sulfate added.

85-5-5-5 bronze was tested only in liquid without ferric sulfate. Corrosion was uniform at less than 5 mpy. No pitting or crevice corrosion was reported.

Nickel-Based Alloys

Monel 400 was the only nickel-based alloy tested. In spray without ferric sulfate, the uniform corrosion rate was 2.1 mpy, while in the resulting liquid, the rate was less than 5 mpy. No localized attack was reported.

Addition of ferric sulfate to the spray decreased uniform corrosion sixfold, but caused pitting (4.9 mpy) and incipient crevice corrosion.

4.20.2.2 Corrosion Fatigue Study

Test Methods

Fatigue tests were performed using strain-controlled, reverse-bending strip specimens in The Geysers steam exposure tests (Ivy and Friedrich 1979). AISI 403 and 422 martensitic stainless steel were tested in steam taken from the inlet line for Unit 7. Steam temperature and pressure in the test chambers were adjusted to 338°F at 100 psig to simulate conditions in the first and second stages of the turbine (where most of the failures are found to occur).

Typical chemical analysis of the steam is shown in Table 4.20-2. These values varied slightly with time throughout the test.

Testing in room temperature air was carried out using these materials in order to have reference S-N (fatigue) curves to compare with the steam exposure tests.

Rectangular specimens 2 x 7.5 x 0.1 inch with a 0.025-inch central stress-concentration hole, K_t nominal = 2, were tested in a reverse-bending machine modified to permit simultaneous testing of three specimens. Side deflections of the top grips during cycling were varied from +0.5 inches to +0.2 inches to produce varying strain levels (3100 to 1200 μ in/in) next to the center hole. Static calibration was performed at room temperature with strain-gauged specimens.

Test specimens were rough-machined, heat-treated to HRC 22 as shown in Table 4.20-6, and finished-machined by blanchard grinding, lapping, and polishing with 600 grit SiC paper. The central hole was honed to produce a smooth, consistent finish.

Heat treatments were chosen to produce homogeneous, fully hardened, martensitic structures tempered to HRC 20 to 25, the hardness found in The Geysers turbine blades. Higher hardness would increase fatigue strength in air, but turbine manufacturers restrict the tempered hardness

TABLE 4.20-6. HEAT TREATMENT OF ALLOYS AT THE GEYSERS

AISI	HEAT TREATMENT	AUSTENIZING TEMPERATURE °F	TEMPERING TEMPERATURE °F	TEMPERING TIME (Min.)	HARDNESS HRC
403 ^a	2	1814	1202	60	23
403 ^a	3	1814	1202	80	24
403 ^b	4	1814	1112	60	28
422 ^a	7	1904	1400	120	22
403 ^a	8	1904	1256	60	21

^aFully hardened and tempered martensite

^b26 mil case of HRC 28. Core hardness is HRC 24.

Source: Ivy and Friedrich 1979

of critical parts such as blading to below HRC 25 to prevent sulfide-stress cracking (SSC).

Tests were run up to a hundred million cycles or to failure, with complete fracture constituting failure. The data were plotted as number of cycles to failure versus strain. Sources of error for stress and strain values were estimated to be about two percent and were considered negligible (Ivy and Friedrich 1979). Over 100 specimens were run for each set of parameters to substantiate the plotted S-N curves.

Results and Discussion

The five heat treatments (see Table 4.20-6) demonstrated a classical "knee" curve when tested in dry air. This indicates that failure is due to fatigue. Heat treatments (HT) 2, 3, 7, and 8, which produced a hardness of HRC 21 to 24, showed similar fatigue strengths (46 ksi). HT 4 had a higher fatigue strength of 54 ksi. The higher strength resulted from accidental surface carburization during heat treatment. The surface hardness of HT 4 was HRC 28. The core hardness was HRC 22.

In geothermal steam, there was no distinct "knee" in the S-N curve. This means that there is no fatigue stress below which failure would not occur. Under these conditions the behavior of the alloys can be compared in terms of Fatigue Endurance Limit (FEL) (the maximum stress which does not cause failure in a given number of cycles). Results are presented in Table 4.20-7 and discussed below.

TABLE 4.20-7. REDUCTION IN FATIGUE STRENGTH IN THE GEYSERS GEOTHERMAL STEAM

AISI	HEAT TREATMENT	HARDNESS HRC	FATIGUE STRENGTH AT 10 ⁷ CYCLES		
			AIR (ksi)	GEYSERS STEAM (ksi)	PERCENT REDUCTION
403	2	23	46	35	24
403	3	24	46	38	17
403	4	28	54	45	20
422	7	22	46	33	28
403	8	21	45	39	13

Source: Ivy and Friedrich 1979

Based on a study of the fatigue behavior of AISI 403 and 422 stainless steel in air, geothermal steam, and clean, generated steam (Ivy and Friedrich 1979), the following conclusions are offered:

AISI 403 and 422 stainless steels exhibit similar fatigue limits (46 ksi at 100 million cycles) in air when the specimens are heat-treated to an equivalent hardness typical of low pressure, steam turbine blade specifications (HRC 21 to 24).

In geothermal steam, no distinct fatigue limit is observed. The FEL at 100 million cycles decreased 13 to 28 percent, depending on the alloy and heat treatment.

Tempering AISI 403 for longer times (HT 3) causes a slight (8.6 percent) increase in the Fatigue Endurance Limit at 100 million cycles, compared to HT 2.

Tempering AISI 403 at higher temperatures (HT 8) caused an 11 percent increase in FEL at 100 million cycles.

AISI 422 (12Cr-1Mo-0.25V) can be heat-treated to higher strengths than AISI 403 (12Cr). However, in geothermal steam at The Geysers, AISI 422 has a lower (by 2 to 6 ksi) FEL at 100 million cycles, when compared to AISI 403 at the same hardness (HRC 22).

4.20.2.3 Field Tests with Nonmetallic Materials

See Section 5.1 for information concerning testing of polymer cement at The Geysers.

4.20.3 Operating Experience

The successful operation of The Geysers provides valuable operating experience for vapor-dominated geothermal resources. The experience is also valuable for liquid-dominated resources, provided that thorough separation and scrubbing of the steam to remove chloride are performed. Materials experience in the various parts of the power plants is discussed in the following sections.

4.20.3.1 Wellhead and Surface Equipment

Carbon steel is suitable for wellhead equipment and pipelines transporting dry steam at The Geysers. The dry steam is not corrosive, but steam condensate may be very corrosive if oxygen is allowed to enter the system (Ellis 1979).

When a turbine is tripped offline, the steam is discharged through silencers. There are two types of silencers. The first type is a redwood box filled with pumice blocks. Steam is discharged through a slotted pipe buried in the pumice blocks. These silencers are reported to be reliable.

A second type of silencer was recently constructed. This unit is a large steel stack. Steam enters the stack through a pair of perforated cylindrical diffusers. Initially, this muffler was equipped with diffusers of AISI 304 stainless steel. One diffuser was completely destroyed after about twenty use cycles, while the other was badly cracked.

A failure analysis indicated that the diffusers failed primarily by chloride-SCC (McAlpin and Ellis 1980). It was concluded that conditions promoting chloride-SCC were produced when alternating wet-dry conditions concentrated the chloride from the steam. High vibrational stresses also contributed to the failures.

4.20.3.2 Turbines

Thirteen of the fifteen power units at The Geysers were provided by Toshiba Turbines. Turbine blades, shrouds, and stays are AISI 403 stainless steel. Early turbine blade problems indicated erosion-corrosion of the blades and cracking of the stays.

The turbines were mechanically redesigned. Blade-passing velocity was reduced, and the blade root was thickened to increase strength. Problems were significantly reduced by these changes with no change in materials (Ellis 1979).

Corrosion-fatigue of the AISI 403 blades (HRC less than 24) and shrouds is a problem at The Geysers. This has lowered the plant availability factor (Hanck and Nekoksa 1976) and resulted in scheduling of more frequent turbine overhauls than in conventional plants (Ivy and Friedrich 1979).

Corrosion-fatigue cracking has usually occurred in the first or second turbine stages, though some failures have occurred in later stages. In some cases, the cracks originate in the braze alloy which secures the Stellite erosion inserts to the AISI 403 blades. No cracking of the blade root area or of the turbine shaft has been reported.

Failures occur in the stage (usually first or second stage) of the turbine where condensation first occurs (Ivy and Fredrich 1979). Impurities in moisture films are most concentrated at this point in the turbine.

It is worth noting that at Cerro Prieto, Mexico, the turbines are fed saturated steam, and all stages are washed by condensate. It has been reported that no cracking of 12Cr (HRC less than 22) turbine blades has occurred in five years of operation (Mercado 1979).

4.20.3.3 Condensers and Cooling Water Systems

All of the generating units at The Geysers use steam condensate for cooling water. Typically, the cooling towers operate at six cycles of concentration. Table 4.20-2 gives a typical condensate analysis. Even with no treatment to abate hydrogen sulfide, the aerated condensate cooling water is very corrosive. Cast iron, Ni-resist cast irons, and carbon steels are unsatisfactory for this service.

Units 1 to 12 are equipped with direct contact (barometric) condensers. These condensers are clad with AISI 316 stainless steel (Bruce 1964). Pumps are fabricated from cast equivalents of AISI 316 (such as ACI designations CF-3M, CF-8M, and CF-12M) (Bruce 1964; Hanck and Nekoksa

1976). The piping is AISI 316 or Fiber-Reinforced Plastic (FRP). The cooling water channels are epoxy-coated concrete. Cooling towers are redwood with redwood, styrene, or PVC fill. They are assembled with AISI 302 nails.

Hydrogen sulfide abatement in these systems is accomplished by adding ferric sulfate (30 ppm ferric ion). The ferric ion reacts with hydrogen sulfide to produce elemental sulfur and ferrous ion. The ferrous ion is regenerated to ferric ion in the cooling tower. Ferric ion is a corrosive species, and addition of ferric ion has caused pitting of the AISI 316 pipes (Hanck and Nekoksa 1976) and of the cast AISI 316 pumps.

Units 13 to 15 are equipped with tube-and-shell surface contact condensers. (Future units are to be similarly constructed.) Cooling water flows on the tube side of the AISI 304 stainless steel. Steam is condensed on the shell side. The condensing steam is acidified to a pH between 5 and 6 to prevent hydrogen sulfide from dissolving in the condensate and escaping from the cooling tower. The noncondensable gases, including the hydrogen sulfide, are pumped to a Stretford reactor for hydrogen sulfide abatement. Acidification of the condensate to a pH between 5 and 6 will increase the corrosiveness, but these units have not been in operation long enough for significant corrosion data to be obtained (Ellis 1979).

4.20.3.4 Electrical Equipment

Hydrogen sulfide emissions from the power plants cause continual maintenance problems with electrical equipment because the hydrogen sulfide corrodes copper or silver electrical contacts. This causes frequent malfunctions of telephones, computers used to monitor plant operations, and switching equipment. Pocket calculators last about six weeks at The Geysers (Ellis 1979).

Computers and other electronic equipment are housed in positive pressure clean-air rooms. These rooms are supplied with air filtered to remove hydrogen sulfide. In practice, it has been difficult to maintain sulfide-free conditions (Ellis 1979).

The other method of combatting the corrosion of copper and silver contacts by atmospheric hydrogen sulfide is the replacement of all copper, copper alloy, or silver contacts with corrosion-resistant parts. Terminals are dipped in solder, and switch contacts and relay points are cadmium-plated.

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5.0 NON-METALLIC MATERIALS IN GEOTHERMAL SERVICE

The search for construction materials for use in geothermal environments has concentrated primarily on metallic materials. Nonmetallic materials are currently receiving more attention. Nonmetallic materials such as elastomers are needed for well drilling and logging, stimulation, and energy extraction equipment. Materials such as plastics, polymer concrete, fiber-reinforced plastic laminates, ceramics and refractory cements appear to be cost-effective replacements for metallic materials in piping systems and process vessels (Burns and Roe Industrial Services Corp. 1977; Burns and Roe Industrial Services Corp. 1979.) Nonmetallic materials might also be used in equipment foundations and cooling towers.

Investigating the performance of nonmetallic materials in geothermal environments is still in an early stage, though an extensive investigation of cement has been performed at Larderello, Italy (Benvenuti, undated). Elastomers, polymers concretes, and cements for use in well completion systems have been studied most often. This work is continuing, and experimentation with polymers, ceramics, and refractory cements for geothermal uses has begun recently.

5.1 Cement Practice at Larderello, Italy

The cooling towers at Larderello are reinforced concrete. Portland cement and the calcareous-type aggregates have been shown to be completely unsuitable for this purpose. The most reliable cements are the Pozzolan and the slag cements. Their compositions are given in Table 5.1-1.

The hydration products of the Pozzolan and the slag cements include dicalcium silicate, tricalcium aluminate, and tetracalcium aluminoferrite. The dicalcium silicate has a higher resistance to sulfates and carbon dioxide present in geothermal condensates than does tricalcium silicate. It does, however, produce a concrete with a lower initial hardening rate and mechanical strength than Portland cement. The presence of even a small percentage of calcium aluminate also provides resistance to sulfates and to waters containing a few ppm sulfuric acid and up to 200 ppm carbon dioxide. The Portland cements, however, are quickly altered and deteriorate in such an environment.

The geothermal fluids have a much greater effect on the aerated walls of the cooling tower and tunnel vaults. In certain areas of the tower and vaults, the fluid has a pH of 2 to 4. Under these conditions, Portland cement is destroyed, and sulfate formation is extensive. The Pozzolan and slag cements are also affected, but the kinetics are slower. After a few years, the soft surface layer is only 0.4 to 0.8 inch deep. In addition, the rate of degradation in these cements decreases with depth and time due to the formation of impermeable gels which slow the attack.

TABLE 5.1-1. AVERAGE CHEMICAL COMPOSITIONS OF CEMENTS

MATERIAL CHARACTERISTICS	CEMENT		
	Slag	Pozzolan	Portland
Loss on ignition (percent)	1.95	4.45	1.90
SiO ₂ and insoluble residue (percent)	29.00	32.34	20.6
Fe ₂ O ₃ (percent)	7.00	4.13	3.1
Al ₂ O ₃ (percent)	5.00	6.40	5.9
CaO (percent)	48.39	48.14	64.3
MgO (percent)	5.26	2.50	2.0
SO ₃ (percent)	1.96	1.04	2.3
CaO free (percent)	0.50	1.50	0.7
Specific gravity (g/cm ³)	2.90	2.985	---
Time of setting (hr) ^a			
Initial	2.5	4.25	---
Final	6.0	11.0	---

^aThese cements should never be cured for less than 28 days. There is not sufficient chemical resistance to geothermal fluids until that time even though mechanical strength may be satisfactory. The recommended curing time minimum for basin bottoms or walls below water-level is about a month. Curing time for tunnel-vaults and cooling tower chimney should be extended to at least two months.

--- Data not available

SOURCE: Benvenuti (undated)

In order to obtain satisfactory behavior from the Pozzolanic and slag cements, the curing times specified in table 5.1-1 must be used. If these curing times are altered, there is premature and extensive deterioration. This occurs especially above the condensate level where hydrogen sulfide and air most severely damage the cements.

When hydrogen sulfide and air contact the well-cured, slightly humid cooling tower walls, sulfur crystals form as a result of an exothermic oxidation reaction. The attack on the cement follows at a rather

slow rate. However, gypsum forms on insufficiently-cured, damp cement walls, and attack begins within a few months.

The operational lifespan of the cements can be prolonged by selecting suitable materials and following these precautions.

1. Select materials with aluminum oxide, ferric oxide ratio > 0.64 and silica, aluminum oxide ratio ≤ 5 (especially when using Pozzolanic cements).
2. Reduce the water/cement ratio to far below 0.5 using suitable additives. These are fluidifiers, which are mainly based on synthetic polymers. Fluidifiers provide rheoplasticity for the concrete.
3. Adhere to the recommended curing times.

The aggregates used in cements for geothermal plants must be siliceous and have good resistance to scaling. Material with 85 percent silica content performed equally as well as the entirely siliceous materials.

In structures with very closely placed reinforcements, the concrete must be sufficiently fluid to fill the spaces between the reinforcing rods. This is accomplished by using fluidifiers, not by increasing the water/cement ratio. In this way, casts with low porosity and permeability are obtained which make it very difficult for condensate to reach the iron reinforcements. At the same time, there is no weakening of the mechanical and chemical characteristics of the cement (Benvenuti undated).

5.2 Concrete Polymer Composite

Brookhaven National Laboratory is conducting a program to develop concrete polymer composites which can be used as construction materials for handling geothermal brines and steam at temperatures up to 570°F. Two types of composites, polymer concrete (PC) and polymer-impregnated concrete (PIC), are being studied.

Most of the work to date has been with PC. The pre-mix nature of PC lends itself to field application. It has superior durability in low pH brines compared to PIC.

The durability of polymer concrete depends on its aggregate composition. An aggregate containing mixtures of silica sand and Portland cement is required for use in a geothermal environment. Evidence shows that calcium oxide reacts with vinyl groups in the monomer to form thermally and chemically stable materials (Sugama and Kukacka 1979).

5.2.1 Laboratory Tests

Long-term (greater than 8 months) test data are available for four monomer groups:

1. 60 weight percent styrene-40 weight percent trimethylolpropane trimethacrylate (TMPTMA),
2. 50 weight percent styrene-33 weight percent acrylonitrile - 17 weight percent TMPTMA,
3. 55 weight percent styrene-36 weight percent acrylonitrile - 9 weight percent TMPTMA, and
4. 50 weight percent styrene-35 weight percent acrylonitrile - 5 weight percent acrylamide - 10 weight percent divinyl benzene.

The mechanical and chemical resistance properties of some of these formulations have been reported (Kukacka 1978). The initial marked strength reductions, noted in Table 5.2-1, were attributed to unreacted monomer in the sample. The problem was solved by using two stage polymerization procedures (Zeldin et al. 1979). Adding acrylamide and divinyl benzene to styrene-acrylonitrile mixtures has produced very high strength and durable materials (see Table 5.2-1).

The acid resistance of polymer concrete has also been determined. No evidence of attack was found in three monomer formulations after 440 days in pH 1 hydrochloric acid at 195°F nor after 170 days in pH 1 hydrochloric acid at 390°F.

5.2.2 Field Test Results

In addition to these lab tests, field tests on polymer concretes have been performed at several locations where geothermal development is in progress. The tests took place under the following conditions:

- dry steam,
- low temperature/low total dissolved solids fluid,
- medium temperature/medium total dissolved solids fluid,
- flashing brine, and
- high salinity brine.

TABLE 5.2-1. COMPRESSIVE STRENGTH OF PC^a AFTER EXPOSURE TO 25% BRINE AT 460°F

MONOMER COMPOSITION, (WT%)				COMPRESSIVE STRENGTH (PSI)						
St ^d	ACN ^e	Aa ^f	DVB ^g	Preparation	30 Days in Brine	120 Days in Brine	240 Days in Brine	360 Days in Brine	480 Days in Brine	600 Days in Brine
52.5	40	5	2.5	27,788 ^b	30,726 ^b	18,590 ^b	23,334 ^b	18,547 ^b	18,086 ^b	13,865 ^c
62.5	30	5	2.5	29,358	32,927	20,577	25,364	19,786	25,265	20,000
50	40	5	5	27,478	28,440	21,891	21,368	19,722	17,955	16,157
50	37.5	5	7.5	25,619	34,381	24,103	25,970	21,808	23,582	21,929
50	35	5	10	26,217	34,466	23,483	33,632	21,463	29,601	23,452

^aPC composition: 13 wt. percent polymer-61 wt. percent silica sand-26 wt. percent Type III portland cement polymerization initiator, 0.5 wt. percent AIBN

^bTested at 68°F

^cTested at 302°F

^dSt; styrene

^eACN; acrylonitrile

^fAa; acrylamide

^gDVB; divinyl benzene

Dry Steam

PC samples have been exposed to 460°F dry steam for a year at The Geysers (see Table 5.2-2). Improved polymerization techniques and a larger concentration of Portland cement would greatly improve the stability of PC under dry steam conditions.

TABLE 5.2-2. COMPRESSIVE STRENGTH OF PC^a AFTER EXPOSURE TO DRY STEAM

MONOMER COMPOSITION (WT%) ^b			COMPRESSIVE STRENGTH (PSI) AFTER EXPOSURE FOR			
St	ACN	TMPTMA	0 Days	60 Days	90 Days	360 Days
50	35	17	10880	4496	4350	4350
50	36	9	10880	—	4930	4350

^a PC composition: 13 wt. percent polymer-78 wt. percent silica sand-9 wt. percent Type III portland cement

^b St; styrene

ACN; acrylonitrile

TMPTMA; trimethylolpropane trimethacrylate

Low Temperature/Low Dissolved Solids Fluid

Brookhaven National Laboratories prepared 48 samples of polymer concrete, polymer impregnated concrete, and a glass polymer composite for testing at the Klamath Falls KGRA. The three materials were tested before exposure and after being submerged for three months and six months in six geothermal wells. The performance of the materials was evaluated by measuring the compressive strength and boiling water absorption of the materials before and after exposure. The results are given in Table 5.2-3. The compressive strength of polymer concretes can decrease by 20 percent within six months of exposure to geothermal fluid. None of the polymer concretes exhibited any cracking (Lund 1976).

TABLE 5.2-3. RESULTS OF POLYMER CONCRETE SAMPLE TESTS

MATERIAL TESTED	WELL TEMP. (°F)	WITHOUT EXPOSURE				180 DAY EXPOSURE			
		Compressive Strength (psi)		Boiling Water Absorption (%)		Compressive Strength (psi)		Boiling Water Absorption (%)	
Polymer concrete	159	8889	8518	—	—	6416	7929	1.4	1.3
Polymer concrete	210	8889	8158	—	—	6357	8352	2.1	1.1
Polymer-impregnated concrete	159	14188	10690	1.5	1.9	11226	9552	0.6	0.6
Polymer-impregnated concrete	210	14188	10690	1.5	1.9	7523	9772	1.2	1.0

— Data not available

Source: Lund 1976

Medium Temperature/Medium Total Dissolved Solids Fluid

In one test at the East Mesa site, an 8-foot long section of PC (12 weight percent concentration of a 60 weight percent styrene-40 weight percent TMPTMA, etc.)-lined carbon steel pipe was exposed to 70 gal/min of a 26,000 ppm fluid at 320°F. No deterioration or scale accumulation was detected. A two-inch layer of scale formed on a carbon steel pipe after 200 hours downstream of the PC test section (Kukacka 1978).

A prototype, 24-inch diameter x 6-foot long PC-lined steam separator and the ancillary piping have been tested since February 1979. Four PC formulations capable of withstanding the 320°F operating temperature were used for liners. The formulations are given in Table 5.2-4. Operation of the unit has been trouble-free thus far.

Flashing Brine

Two monomer mixtures, 60 weight percent styrene-40 weight percent TMPTMA and 50 weight percent styrene-33 weight percent acrylonitrile-17 weight percent TMPTMA, mixed with an aggregate of 90 weight percent silica sand and 10 weight percent Portland cement, were tested. They were exposed to flashing brine at 320°F for 180 days and were crack-free at the end of the time period (Kukacka 1978).

High Salinity Brine

Two series of experiments have been performed at the Bureau of Mines Materials Testing Facility using Salton Sea geothermal fluid (Kukacka et al. 1978).

In one test, pipe lined with a 0.5-inch thick monomer mixture of 55 weight percent styrene-36 weight percent acrylonitrile-9 weight percent TMPTMA, used in conjunction with a 70 weight percent silica sand-30 weight percent type III Portland cement aggregate, was exposed for 90 days to flowing brine (280,000 ppm total dissolved solids) and a temperature of 455°F. Results showed no deterioration of the PC or loss of bond to the steel pipe.

The results of a second test in high salinity brine to measure changes in compressive strength are summarized in Table 5.2-5. A trend toward higher strength with increased exposure temperature is evident and may be caused by the presence of unreacted monomer which was subsequently polymerized.

TABLE 5.2-4. PC FORMULATIONS USED AS LINERS IN STEAM SEPARATOR

MONOMER MIXTURE WT%					MONOMER CONCENTRATION (WT%)	AGGREGATE MIXTURE (WT%)		AGGREGATE CONCENTRATION (Wt%)
St ^a	ACN ^b	TMPTMA ^c	Aa ^d	DVB ^e		SiO ₂	Type III portland cement	
55	36	9	0	0	13	70	30	87
60	0	40	0	0	13	90	10	87
60	0	40	0	0	13	70	30	87
50	35	0	5	10	13	70	30	87

^aStyrene

^bACN: acrylonitrile

^cTMPTMA: trimethylolpropane trimethacrylate

^dAa: acrylamide

^eDVB: divinyl benzene

TABLE 5.2-5. AVERAGE TEST RESULTS FROM SAMPLES EXPOSED FOR 60 DAYS AT U.S. BUREAU OF MINES FACILITY

TEST TEMPERATURE (°F)	ENVIRONMENT	COMPRESSIVE STRENGTH (psi)	DIFFERENCE ^a (%)
68	control	13,141	---
212	sludge ^b	11,722	-10.8
212	brine ^c	16,513	+25.7
212	steam ^d	12,607	- 4.1
338	brine ^e	16,355	+24.5
392	steam ^f	20,940	+59.3
455	brine ^g	20,545	+56.3

^aCompared to controls

Each value represents average of two samples

^bBaker Tank bottom sludge

^cBaker Tank brine, intermittent contact

^dSteam from brine flashed at 100°C

^eBrine from 2nd steam separator, greater than 30 percent salt

^fSteam from 1st steam separator, 1.5 percent salt

^gWell head brine, 28 percent salt

5.3 Cements

In geothermal processes, cements can be used as corrosion-resistant lining materials and in well completion systems.

Protective Liners

Five cement materials have been tested for use as protective liners in seawater at 250°F. Test results are given in Table 5.3-1. Only

TABLE 5.3-1. PERFORMANCE OF CORROSION RESISTANCE CEMENTS IN 250°F SEAWATER (12-MO EXPOSURE)

NAME	TYPE	APPEARANCE
Prekrete G-8	Alumina-Silicate	Excellent condition
Saureisen-Electrical Refractory Cement, No. 75	Calcium Aluminate	Good condition
Prekrete C-17	Calcium Oxide	Fair condition
Lumnite	Calcium Aluminate	Poor condition
Saureisen-Pourlay No. 54	Sodium Silicate	Complete failure

Prekrete G-8 withstood the exposure and did not degrade or break. In addition, Prekrete G-8 has given good service after six years in a desalinization facility at Freeport, Texas. Prekrete G-8 lining can provide excellent corrosion resistance in a wide range of solutions from dilute acid to dilute caustic and can handle temperatures up to 1000°F. Its coefficient of expansion is about the same as that of carbon steel. Long distance shipping of Prekrete is usually uneconomical due to cracking and chipping of factory-lined pipes. An experienced and licensed local contractor is necessary for lining of pipes in the field, which makes Prekrete linings relatively expensive. Failures of Prekrete linings have been associated with inadequate welding of the screens that are used to increase the bond between lining and steel. Field repairs are not difficult.

Well Cements

When a geothermal well is drilled, a steel casing must be run into the hole and secured with some type of cementing material. Costly blowouts in some geothermal wells have been caused by failure of cementing materials. In particular, the tendency of Portland cement systems to degrade under extreme temperatures have been documented. (Eilers et al. 1977).

A 1977 Dowell study of the state-of-the-art of geothermal well cements revealed the following:

1. Most Portland cement systems change composition rapidly at 450° to 600°F but stabilize within one or two weeks.
2. The addition of 30 to 40 percent fine silica to normal Portland cement largely alleviates the cement's strength retrogression.
3. Most nonreactive cement additives can be admixed in moderation with a stabilized cement system without adversely affecting temperature stability.
4. Delayed high temperature retrogression occurs in pozzolan-extended Portland cement systems, especially those containing fly ash.
5. A high temperature cement should not contain large amounts of bentonite, diatomaceous earth, or expanded perlite unless silica is added to stabilize the system.
6. A non-Portland cement, Class J, had the least overall variation of all systems tested (Eilers et al. 1977).

The U.S. Department of Energy (DOE) is currently evaluating diacalcium silicate cements, alumina-phosphate cements, high alumina and magnesia cements, hydrothermal cements, and modified Portland cements. Several materials show great promise (Kukacka et al. 1978). Two recent reports (Gallus, Pyle, and Watters 1978; Gallus, Pyle, and Morgan 1979) indicate that API Class G cement, stabilized with 35 percent silica flour, is a satisfactory cementing composition for use in dry steam wells at 465°F and in brines at temperatures of 559°F.

5.4 Elastomers

Most high temperature polymer work done in the past has studied performance under conditions found in aerospace applications. Since geothermal stresses are much different than those exerted by the aerospace environment, few of the published stability data are valid for geothermal applications. DOE is currently investigating new elastomers for geothermal uses such as packer seals for the cased hole, O-rings for instruments, drill bit seals (O-rings or reed ovals), and logging cable covering and insulation. The three DOE elastomer research areas include (1) basic research on synthesis of new polymers; (2) development, formulation, and testing of known materials; and (3) applications, prototype production, and evaluation.

5.4.1 Basic Research

In the effort to synthesize new polymers which will retain their elastic character under geothermal exposure, siloxane and fluoroalkane polymers were studied. Out of all the tested polymers of this type, only one, a copolymer containing butadiene, perfluoroalkylene, and phenylene oxide moieties, could be cured to a product which was stable in steam at 525°F.

Another approach was to produce a material which would be hard and inflexible at room temperature, but elastomeric at utilization temperature. Using this approach, a graft copolymer (polyphenylquinoxaline (PPQ) blocks pendant to polystyrene) was synthesized. This copolymer gave tensile strengths to 350 psi and elongations of 18 to 36 percent at 500°F in nitrogen (Cassidy 1979).

The third approach to synthesizing new polymers was to modify the surface of elastomers to improve their surface life, which is often degraded in a geothermal environment. The principal advantage of this particular approach is that commercially available products could be treated without any change in configuration or production process. Results of stability tests are shown in Table 5.4-1. It is interesting to note that in some cases coatings lower the stability of the base rubber, perhaps by prohibiting the escape of harmful degradation by-products.

5.4.2 Development

The second major area of DOE's geothermal elastomers research focused on modifying commercially available elastomers for geothermal use.

General Screening

First, a general screening of commercial elastomers took place. Over 37 variations of a basic carborane-siloxane gum stock (Union Carbide "Ucar-Sil") were cured and tested. Results of hydrolytic stability tests are summarized in Table 5.4-2.

Screening for Use as Pipes, Nozzles and Turbine Blades

Various elastomers were then screened for possible use as pipe, nozzles, and turbine blades. Thermogravimetric analysis (TGA) was used to test weight loss in hot brine at high pressure. Tests were carried out both in the field and in artificial brine. Table 5.4-3 summarizes tests made in artificial brine at 572°F. A few materials performed well: carbon/carbon fiber composite, Teflon, polybutadiene and its glass composite, PBI, and Hercules H-resin with aluminum oxide filler.

TABLE 5.4-1. STABILITY OF COATED ELASTOMERS

BASE ELASTOMER	COATING	TEST CONDITIONS	CHANGE IN STABILITY
Kalrez (perfluoropolyether)	PTFE ^a	dry sour gas 1 month 392°F	no improvement
Buna-N (butadiene-acrylonitrile copolymer)	PTFE	dry sour gas 1 month 392°F	no improvement
Viton (fluoroelastomer)	PTFE	dry sour gas 1 month 392°F	improved
Viton (fluoroelastomer)	PTFE	dry sour gas 572°F	no improvement
EPR (ethylene-propylene rubber)	PTFE	wet sour gas 527°F	improved
Viton	CF ₄ or argon	wet sour gas 527°F	no improvement
EPR	CF ₄ or argon	wet sour gas 527°F	no improvement
Viton	Parylene N or C	wet sour gas 572°F	decreased stability
EPR	Parylene N or C	wet sour gas 572°F	decreased stability
Viton	Parylene N or C	wet sour gas 527°F	slight improvement (blistering)

^aPoly(tetrafluoroethylene)

Source: Cassidy 1979

TABLE 5.4-2. HYDROLYTIC STABILITY TESTS

TEST NO.	MATERIAL	VISUAL RESULTS
1	Carborane-siloxane rubber	Complete deterioration
2	HAC amide fluoroelastomer (solid)	Bad disintegration
3	Krytox 143-AC perfluoroalkyl polyether lubricating oil mol wt. = 5000	Very little or no effect seen
4	OS-124 (pentaphenylene oxide)	Appeared significantly affected, water very cloudy
5	Braycote 816z perfluoroalkyl polyether copolymer lubricating oil mol wt. = 13000	Slight cloudiness in solution
6	Teflon TFE	No discernible effect
7	Diphenyl ether	Large amount of cloudiness
8	Polyphenylene oxide pellets	No evidence of depolymerization
9	HAC ketone fluoroelastomer ^a	Slight deterioration
10	Silicone rubber - 50 shore ^b	Complete depolymerization
11	Polyphenylene sulfide ^c	No apparent effect except lighter color
12	Kalrez ^c	No apparent effect

^aRun for 45 hours at 450°F

^bThese tests run at 450°F and 400psi

^cThese tests were run at 527°F for 72 hours

Source: Cassidy 1979

Several polymers were also tested at 480°F in artificial brine. The purpose was to investigate the performance of lower cost materials under less severe test conditions. Table 5.4-4 compares results of tests at different exposure times and temperatures.

TABLE 5.4-3. ELASTOMER WEIGHT CHANGE AFTER 72 HOURS AT 572°F IN ARTIFICIAL BRINE

MATERIAL	% WEIGHT CHANGE AT 72 HOURS
Polybenzimidazole Foam (Imidite SA)	+79 ^b
Polyimide (Kerimid 601)/Thornel 400 Carbon Fiber (60%)	+35 ^a
Polyaromatic (Hercules H-Resin, HA-54) with 40 wt % Al ₂ O ₃	+ 6
Carbon/Carbon fiber Composite	+ 4
Polytetrafluoroethylene (duPont Teflon TFE)	+ 1
Fluorinated (perfluoroalkoxy) Copolymer (duPont Teflon PFA)	0
Polyaromatic (Hercules H-104 Resin)	0
Polyaromatic (Hercules H-124) with 50 wt% Graphite	0
Polyphenylquinoxaline/Carbon Fiber (60%)	0
Polyaromatic (Hercules HA-54 Resin, Stabilized) with 40% wt Al ₂ O ₃	- 1
Poly-1,2-butadiene (Firestone Dienite X-644) with 10% Chopped Glass	- 2
Phenolic/Fiberglass (Ferro Corp.) (70%)	3(10% for polymer)
Poly-1,2-butadiene (Firestone Dienite X-644) with 10% Chopped Glass	- 5 ^a
Poly-1,2-butadiene (Firestone Dienite X-644) with 10% Chopped Glass	- 5 ^a
Polybenzimidazole (Whittaker Imidite 2803)	- 5
Poly-1,2-butadiene (Firestone Dienite X-643) with 20% Chopped Glass	- 8(10% for polymer)
Poly-1,2-butadiene (Firestone Dienite X-643) with 20% Chopped Glass	- 9(10% for polymer)
Polyphenylene Sulfide (Phillips Ryton) with 40% glass fiber	Flowed ^d
Polyimide (Meldin)	31
Epoxy/Thornel 50s Carbon Fiber (40%)	-43(100% of polymer)
Aromatic Polyester (Carborundum Ekonol 900)	-69
Carborane (Olin Dextsil-201)	-82
Polyimide (duPont NR 150B)	-100
Polyimide (dePont Vespel)	-100
Polyimide (Monsanto Skybond 700)	-100
Polyamide (duPont KS Polyamide)	-100

^a The PBI foam showed gains of 79 wt percent at 144 hours and 82 wt percent at 240 hours, indicating that the foam had filled with salts from the 25 wt percent salt content brine. These salts could not be washed out readily and remained upon drying to constant weight.

^b The polymer was undoubtedly removed by the hot brine, leaving a porous fiber matt to collect salts.

^c Temperature rose to 742°F for 16 hours

^d PPS flowed during the test, breaking into smaller pieces all of which could not be recovered. It was not felt that the polymer was necessarily degraded however.

Source: Cassidy 1979

To test erosion resistance, other materials were tested as nozzles which were subjected to impingement of a stream from a flowing well. Some deposition occurred on Teflon-PFA nozzles, but this was easily removed. Polyamides eroded badly, but PPQ allowed scale accumulation. Teflon PFA was superior to Teflon TFE in erosion resistance.

TABLE 5.4-4. WEIGHT LOSS VERSUS TIME IN ARTIFICIAL BRINE

MATERIAL TESTED	72 HOURS		202 HOURS	
	482°F	572°F	482°F	572°F
Dienite X-555	-0.11%	-8.9	-1.7%	-15%
Dienite X-644	-1.9	-3.6	-2.3	- 7
H-104	-0.4	-0.6	- .9	----
HA-54	-0.2	-1	0	----
Imidite 2803	-3.9	-5	-4.9	- 6

Source: Cassidy 1979

Screening for Moisture Blocking

A metal (Corroseal) and a Kalrez O-ring were tested for their ability to prevent moisture from entering logging tools. After 100 hours at 518°F and 4800 psi differential pressure, the metal joint showed no effect while Kalrez failed catastrophically.

Screening of Commercial Specialty Elastomers

Fluorinated polyalkylenes (Viton and Aflas), fluorinated polyalkylene ethers (Kalrez), and an aromatic polymer (Noryl) were compounded with fillers, stabilizers, and curing agents and tested in several ways. The most important of these tests was a stress-relaxation (SR) measurement which evaluated the elastomer in a situation similar to actual use conditions.

Weight loss was measured for Viton and other formulations during aging in brine at 482°F (see Figure 5.4-1). Tensile properties for various materials were also monitored during aging in brine at 486°F. The results

appear in Figure 5.4-2. Kalrez and Aflas 150H appear to be superior. It should be noted that Kalrez, although superior to other elastomers, is very expensive (\$1820/lb) and must be processed by duPont. Furthermore, the thickness of samples is limited to a 0.25-inch maximum. Therefore, its use is limited to small parts, backup films, etc. Aflas, a relatively new product, shows potential for use in geothermal applications, particularly when crosslinked (Cassidy 1979).

FIGURE 5.4-1. WEIGHT LOSS OF FLUORINATED ELASTOMERS DURING AGING IN 482°F IN BRINE

Source: Cassidy 1979

FIGURE 5.4-2. EFFECT OF AGING AT 486°F IN BRINE (SOL.1) AND DEIONIZED WATER (SOL.3) ON ELASTOMER STRENGTH

Source: Cassidy 1979

Application

The use of elastomers for drill bit seals (O-rings or Reed ovals) and packer seals for a cased well have been investigated. Both uses are important for economical drilling and production of geothermal energy.

Drill Bit Seals

An O-ring is vital because it seals a drill bit under extreme conditions of temperature, abrasives, friction, and chemical attack and allows a lubricated bit to have a longer life. The life of elastomer seal rings is affected by a number of factors: (1) heat generated by friction

of the rotating cutter cone; (2) cutter cone wobble; (3) abrasion by rock cuttings; and (4) composition of the grease. A review of commercial elastomer seal materials is presented in Table 5.4-5.

An initial screening was run on four types of elastomers in a Reed oval configuration with an installed compression of 8.5 percent which was raised to 10 percent at 392°F. The results are as follows:

- Buna-N, a widely known and used elastomer, performed well up to 392°F in the absence of abrasives.
- EPR (ethylene-propylene rubber) seals showed poor behavior over 4 hours at 392°F, even with no abrasives.
- A fluorocarbon seal produced from Viton (duPont) or Fluorel (3M) had a maximum use temperature of 455°F for a four-hour test.
- Fluorosilicon seals and those made of PNF (fluorinated polyphosphazenes) and Kalrez proved unsatisfactory.

A longer test was later run at 392°F. General conclusions were as follows:

- The standard drill bit grease was harmful to seals.
- Viton will survive for nearly 100 hours, provided a bentonite-base mineral oil lubricant is used.
- Buna-N has a service life of 18.5 hours in a bentonite-based grease.
- A Parylene-C coating (0.0015 inch) on several seals wore through and showed marginal adhesion.

After 32 hours, a Kalrez O-ring was unaffected, and its manufacturers propose that Kalrez can maintain tensile properties to 554°F. Very recent data show that a Viton-EPR blend has a service life of 47 hours at 392°F. A Kalrez with Kevlar filler also appears promising.

Packer Seals

Packer seals must be compressed in place to seal between the casing and drill stem and also must withstand geothermal stresses and

TABLE 5.4-5. HIGH TEMPERATURE ELASTOMER SEAL MATERIALS

PRODUCT NAME	PRODUCER	MATERIAL CLASS	PROBABLE TEMP. LIMIT	COST/LB.	POTENTIAL COMPATABILITY PROBLEMS	POTENTIAL PHYSICAL PROPERTIES PROBLEMS
Buna N (Nitrile)	Several	Butadiene-acrylonitrile	300°F	Low	High temp water and steam	Low temp limit
Ethylene-propylene (EPDM)	Several	Ethylene-propylene	350°F	Low	Petroleum base fluids	None
Viton	Du Pont	Fluorocarbon	500°F	Low	High temp water and steam	Tear resistance
Fluorosilicone	Dow Corning	Fluorosilicone	500°F	Low	Silicone lubes, water and steam	Tear and abrasion resistance
PNF-200	Firestone	Phosphonitrilic	400°F	\$100	None expected	Unknown
Kalrez	Du Pont	Perfluoroelastomer	500°F	\$2,000	None	Unknown
5AD-7004	Custom Rubber Products	Modified Buna N	450°F	Low	None	Unknown
Viton, Peroxide-Cured	Du Pont/Parker	Fluorocarbon	500°F	Low	High temperature water and steam	Tear resistance
TR-70	Dow Corning	Fluorosilicone (clear)	500°F	Low	Silicone lubes, water and steam	Tear resistance

compressive forces (tensile stress on the outside surface, extrusion, and compression on the inside surface). Considerable success has already been achieved in the use of commercial materials for packer seals.

Elastometric materials have been screened for packer use in ASTM tests and further evaluated in a specially designed laboratory test that employs an extrusion resistometer as a punch test device. ASTM screening tests included measurement of ultimate tensile strength, elongation, swell, compression set, modulus, tear, and Shore A hardness. The effect of chemical stresses was measured by aging samples for 24 hours at 500°F in a fluid containing sodium chloride (25,000 ppm), carbon dioxide (1,000 ppm) and hydrogen sulfide (300 ppm) at pH 5.7.

Four elastomers were reformulated to improve tensile strength, hardness, resistance to extrusion and ultimate elongation properties for geothermal applications. Table 5.4-6 compares the performance of virgin and chemically aged elastomers to the performance of reformulated products.

Elastomers surviving the screening tests were molded into 4-inch packers which were tested in the extrusion resistometer at 500°F with a 4100 psi pressure differential across the seal. Table 5.4-7 gives the results. Table 5.4-8 shows how extrusion behavior of EPDM and FKM formulations varied with temperature.

Table 5.4-9 shows how elastomer properties were changed after aging in synthetic brine for 22 hours at 600°F. Based on the results of all tests, elastomers were ranked for performance in O-ring and packer seal applications in the following order: EPDM, ALFLAS, EPDM/Viton, and Viton (Cassidy 1979).

5.5 Fiber-Reinforced Laminates

Fiber-reinforced plastic (FRP) pipe has excellent corrosion resistance, a low resistance to fluid flow, and ease of handling because of its light weight. The more common types of resin and glass fiber will allow operations at temperatures of 270°F and, if special epoxy or polyester resins are used, operation to 399°F is possible.

To date, FRP materials have not been adequately tested in geothermal systems, but an indication of their potential can be seen in the results of testing in desalinization environments (Fontana and Zeldin 1979), summarized in Table 5.5-1. Testing of FRP material in geothermal environments is now required.

TABLE 5.4-6. EFFECT OF CHEMICAL AGING ON PROPERTIES OF ORIGINAL AND REFORMULATED ELASTOMERS

ELASTOMER	ULTIMATE TENSILE STR. @ RT, PSI		ULTIMATE ELONG. @ RT, %		SHORE A HARDNESS @500°F		EXTRUSION RESIST. @ 500°F PSIA	
	V ^c	CA ^d	V ^c	CA ^d	V ^c	CA ^d	V ^c	CA ^d
EPDM								
Original	>1363	>1020	>840	>840	61	52	9.6	9.5
Reformulated	1610	1554	141	148	92	92	17.1	17.6
FLUOROELASTOMER (FKM) ^a								
Original	1699	244	162	74	80	58	11.2	3.6
Reformulated	2195	1591	244	226	79	79	11.4	6.3
EPDM/FKM ^a								
Original	1882	1506	681	431	67	74	8.3	10.6
Reformulated	1596	1531	193	163	88	89	18	17.3
PERFLUOROELASTOMER ^b								
Kalrez 3073	4377	2337	100	230	92	77	8.8	8.3

^aViton, du Pont Trade name^bdu Pont Trade name, no development for this application, cured test sheets of two available formulations were obtained from du Pont^cVirgin or unaged^dChemically aged at 260°C in synthetic geothermal brine

TABLE 5.4-7. RESULTS OF EXTRUSION RESISTOMETER TESTS AT 500°F
AND 4100 PSI

MATERIAL	TIME TO FAILURE (HRS)
Viton Type 1 (specially formulated)	6.25 - broke
Viton Type 2 (commercial)	4.0 - broke
EPDM (specially formulated)	22.0 - broke
EPDM/Viton (Specially formulated)	22.0 - test stopped
Kalrez (Commercial)	0.75 - broke

TABLE 5.4-8. EXTRUSION BEHAVIOR OF FOUR-INCH PACKER SEALS IN
EXTRUSION RESISTOMETER TEST FIXTURE

ELASTOMETER	DEGREE OF EXTRUSION AT TEMPERATURES OF		
	500°F	400°F	300°F
EPDM	Very Minor	None	None
FKM	Moderate	Very Minor	None
EPDM/FKM	None	None	None

TABLE 5.4-9. EFFECT OF CHEMICAL AGING AT 600°F ON ELASTOMER PROPERTIES

ELASTOMER	ULTIMATE TENSILE STR. @ RT, PSI			ULTIMATE ELONG. @ RT, %			SHORE A HARDNESS @500°F		
	V ^a	CA ^b	% of original	V ^a	CA ^b	% of original	V ^a	CA ^b	% of original
EPDM-267	1257	817	65	116	210	181	91	77	85
Viton-255	2392	failure	0	201	died	failure	80	failure	0
EPDM/Viton-266	1403	978	70	195	23	12	87	97	111
AFLAS-28-	2349	730	31	211	301	143	82	47	88

^aVirgin^bChemically aged

TABLE 5.5-1. FRP LAMINATES IN FLOWING SEAWATER AT 250°F, 30 PSIG
AFTER FIFTEEN MONTHS OF EXPOSURE

RESIN TESTED	PERCENT RETENTION			
	Flexural Strength	Flexural Modulus	Tensile Strength	Appearance Rating ^a
Dow Epoxy-Novalac XD7380	103	94	74	32.1
Shell Bis-Epoxy Epon 828	79	77	66	29.0
Dow Bis-A-Epoxy D.E.R.-331	55	88	46	28.3
Dow Hal. Vinylester Derakane 510	72	91	66	39.7
Dow Vinylester Derakane 470.45	47	99	43	26.9
Dow Vinylester Derakane 411.45	42	65	42	40.4
Quacorr Furane	39	46	35	40.1
Atlas Hal. Polyester Atlac 711.05	35	92	32	43.6
Reichold Bis-A-Epoxy Epotuf 37-130	43	71	29	69.3
Atlas Bis-A-Polyester Atlac 382.05	25	74	23	53.3
Atlas Bis-A-Polyester Atlac 4010-A	23	43	17	70.0
Hooker Ortho-Polyester Hetron 197	17	38	23	70.7
Freeman Ortho-Polyester PolyLite 33.040	25	24	17	74.0
Reichold Ortho-Polyester PolyLite 33-402	13	20	14	75.0
Freeman Iso-Polyester Stypol 40.2989	12	17	14	34.0
Freeman Iso-Polyester Stypol 40.2187	13	16	15	77.8
PPC Iso-Polyester Selectron 5899	7	8	8	74.0
PPC Iso-Polyester Selectron 5899	3	9	b	79.8
Freeman Ortho-Polyester Stypol 40.2187 ^c	5	5	b	77.4

^a0 = No change

^bNot tested due to degradation of sample

^cHigh density air bubble inclusion

Source: Fontana and Zeldin 1979

5.6 Epoxy-Coated Pipe

Epoxy coatings can be applied quickly and inexpensively. Epoxy itself has a high resistance to corrosion. A good surface preparation, however, is crucial for the required adherence. A substantial number of epoxy coating failures have been reported due to blistering and subsequent peeling of the coating. Epoxy coating is recommended only in slightly corrosive environments.

5.7 Asbestos Cement Pipe

Asbestos cement (AC) pipe has been extensively tested at the Raft River geothermal project (Miller, Kunze, and Sanders 1979). In 1975, 4000 feet of AC pipe was installed to transport 300°F geothermal fluids at 150 psi. Although preliminary tests indicated that AC pipe was satisfactory in geothermal conditions, the pipe has been unsatisfactory in practice. Multiple failures due to thermal shock and water hammer have occurred (Reeber 1981).

5.8 Thermoplastics

The durability of thermoplastics in geothermal environments is unproven, although polysulfone has shown no sign of thermal distortion or change in physical properties in seawater tests at 250°F.

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APPENDIX A

CORROSION BEHAVIOR OF SPECIFIC CLASSES OF ALLOYS IN GEOTHERMAL FLUIDS

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A.0 CORROSION BEHAVIOR OF SPECIFIC CLASSES OF ALLOYS IN GEOTHERMAL FLUIDS

Corrosion test results are used to predict materials performance in geothermal fluids. Most of these tests measure the rates of uniform corrosion and localized (pitting and crevice) corrosion of coupon specimens. Some tests on stress corrosion cracking (SCC) in U-bend specimens have been done. The results of these tests are helpful in selecting materials because they can be used to predict how fast a metal deteriorates from uniform corrosion, pitting, or crevice corrosion in specific fluid composition and at a specific temperature and flow rate.

However, uniform and localized corrosion rates measured in test environments do not supply all of the information needed to specify construction materials for piping, vessels, or process equipment. Corrosion rates are dependent on fluid composition and process stream characteristics. Therefore, the test results do not describe materials performance in streams with different compositions, temperatures, pressures or flow rates.

Also, metallic construction materials are subject to other forms of attack besides uniform corrosion, pitting, and crevice corrosion. For example, catastrophic component failures can occur suddenly with little evidence of metal loss due to sulfide stress cracking (SSC). SSC occurs in hard, high-strength alloys under stress and exposed to aqueous environments containing even small amounts of hydrogen sulfide. Hydrogen blistering, another form of attack, causes rupture of metallic materials when hydrogen trapped in voids accumulates at a sufficient pressure. Improper heat treatment of welding can result in intergranular corrosion near grain boundaries (weld decay), which causes alloys to disintegrate or lose strength. Dealloying, the dissolution of one component of an alloy, is another form of corrosion. When cyclic stresses occur in a corrosive environment, failures also occur due to corrosion-fatigue.

The rate at which metals deteriorate depends on some factors that are not taken into account in coupon tests. In practice, it is not a metal coupon but a pipe, vessel, pump, or other equipment item fabricated from metal that fails due to metal deterioration. The rate of metal deterioration and the mode of corrosive attack also depend on fabrication practices, equipment configuration and geometry, and stresses that occur during operation.

The following sections describe the forms and mechanisms of corrosive attack on specific classes of alloys that can occur in geothermal process streams. The generalizations presented are especially useful when materials must be specified for untested conditions. If the corrosion rate of a material has been tested in the stream conditions of interest, these generalizations supplement the test results. Included in the following sections are the effects of fabrication practices, equipment configuration,

and operating stresses. Additional modes of materials deterioration are also identified.

Each section will cover material performance in wellhead and flashed liquid, separated steam, and condensate streams for a major class of metals. Definitions of the kinds of corrosive attack that can occur for a particular metal and the fluid or process stream characteristics that determine corrosiveness are included. The conditions for minimizing attack are also defined, and precautions in design, fabrication, and operation are given.

A summary of the information on metals performance in liquid geothermal streams is presented in Tables A.0-1, A.0-2, and A.0-3 for easy reference. Details can be found in Sections A.1.1, A.2.1, A.3.1, A.4.1, A.5 and A.6.

A.1 Mild and Low Alloy Steels

The low cost, availability, and ease of fabrication of carbon steels (mild steels) make them attractive construction materials for geothermal power plants. However, the reliability of these steels depends upon their applications in the power plants.

A.1.1 General Guidelines for Using Mild Steels in Liquid Geothermal Streams

By taking appropriate precautions, mild steels can be used for thick-walled applications in contact with most geothermal fluids. Thin-walled applications will be limited by the susceptibility of these materials to localized attack such as pitting and crevice corrosion. High-salinity geothermal fluids will cause high uniform and localized corrosion rates and will severely limit the use of low carbon steels. The applications of mild steels to geothermal environments require that precautions be taken for aeration, flow rate, scaling, galvanic coupling, exterior surfaces, and steel specifications.

Aeration - Acceptable uniform corrosion rates of carbon steels in moderately saline geothermal fluids are due mainly to the reducing, oxygen-free nature of the fluids. The introduction of part-per-billion (PPB) quantities of oxygen can greatly increase uniform corrosion and initiate pitting and crevice corrosion.

The effect of oxygen on the corrosion of a mild steel is shown in Figure A.1.1 for an otherwise nearly gas-free seawater stream. The same effect occurs in geothermal systems. The solubility of oxygen in saline fluids decreases with increasing temperature up to 212°F, at which point it increases again (Cramer 1974). The electrochemical reaction rate increases with temperature.

TABLE A.0-1. FORMS AND CAUSES OF CORROSION FOR MILD AND LOW ALLOY STEELS
IN GEOTHERMAL FLUID

MAJOR FORMS OF CORROSION	MAIN ENVIRONMENTAL FACTORS	LIMITS AND PRECAUTIONS	OTHER COMMENTS
Uniform	pH chloride flow velocity	Rapid rate increase below pH 6. Rapid rate increase above 2% Cl ⁻ . Limit flow to 5-7 fps.	Air in-leakage is a major hazard; local flashing in pipes can cause very high flowrates and erosion/ corrosion. Avoid direct impinge- ment on steel.
Pitting, Crevice	temperature chloride scale	Susceptibility increases with increasing temperature and chlo- ride concentration. Remove mill scale; avoid deposits.	See A.1.1.1 for low alloy addi- tions. Avoid mechanical crevice.
Sulfide Stress Cracking	H ₂ S yield strength (hardness) temperature	Can occur at very low H ₂ S levels. Use low strength material where- ever possible. Hazard greater at lower tempera- tures.	Complex interactions; see A.1.1.3.
Hydrogen Blistering	H ₂ S	Use void-free materials.	Possible at very low H ₂ S concen- trations; see A.1.1.4.
Galvanic Coupling	electrical contact with more noble metal	Avoid coupling close to large area of cathodic metal	More severe when material has porous coating or scale.

TABLE A.0-2. FORMS AND CAUSES OF CORROSION FOR STAINLESS STEELS IN GEOTHERMAL FLUID

MATERIAL	MAJOR FORMS OF CORROSION	MAIN ENVIRONMENTAL FACTORS	LIMITS AND PRECAUTIONS	COMMENTS
<u>Ferritic alloys</u>	pitting, crevice	chloride scale stagnant or low flow oxygen	In general, susceptibility increases with increasing concentration and temperature. Avoid scale deposits. Avoid stagnant or low flow conditions. O ₂ greatly increases susceptibility.	Lower alloys may also have high uniform rates in severe environments; oxygen is a hazard. Higher alloys are much more resistant; chromium and molybdenum most effective alloying agents; see A.2.1.1
	intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures; see A.2.1.3.	
<u>Austenitic alloys</u>	stress corrosion cracking	chloride oxygen temperature	Complex interaction; depending on other factors, cracking can occur for Cl ⁻ > 5ppm; O ₂ ~ 100 ppb; T > 60°C.	Hazard increases with increase in chloride, oxygen, T; some alloys more resistant; see A.2.1.2; protect exterior surfaces.
	pitting, crevice	chloride temperature scale stagnant or low flow oxygen	See ferritics above. Avoid scale deposits. Avoid stagnation or low flow conditions. O ₂ greatly increases susceptibility.	Resistance increase with Mo content; avoid mechanical crevices.
	intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures; see A.2.1.3.	
	as above sulfide stress cracking	as above H ₂ S, temperature, stress, hardness	As above. More severe at lower temperatures; use low strength levels where possible.	General corrosion resistance depends on composition. See SSC discussions and A.2.1.4.
<u>Martensitic alloys</u>				
<u>Cast alloys</u>	as above			See comments for equivalent wrought alloy; good crevice corrosion resistance needed for pumps and valves.

TABLE A.0-3. FORMS AND CAUSES OF CORROSION FOR SEVERAL ALLOY CLASSES IN GEOTHERMAL FLUID

MATERIAL	MAJOR FORMS OF CORROSION	MAIN ENVIRONMENTAL FACTORS	LIMITS AND PRECAUTIONS	COMMENTS
<u>Titanium Alloys</u>	crevice, pitting	chloride temperature pH	Maximum temperature for resistance depends on chloride and pH; see A.3.1.2.	Several alloys have much better resistance than pure Ti. Pre-cracked Ti may undergo stress corrosion cracking. See A.3.1.4.
	galvanic coupling	electrical contact with more active metal	Coupling to large area of more active metal may cause hydrogen embrittlement of Ti; see A.3.1.3.	
<u>Nickel Alloys</u>	crevice, pitting	chloride, temperature	Similar to stainless steels except higher alloys more resistant to crevice corrosion; high flow rates.	Resistance depends on alloy composition; see A.4.1. May be susceptible to hydrogen embrittlement when coupled to steel.
<u>Copper Alloys</u>	pitting, uniform, dealloying	hydrogen sulfide chloride, temperature	Hydrogen sulfide as low as 0.1 ppm can cause attack.	Usefulness limited in hydrogen sulfide environment.
	stress corrosion cracking	ammonio, pH	See A.5 for pH and alloy dependence.	
<u>Other Metals</u>				
Cobalt alloys			Avoid galvanic coupling to steel or other active metal.	Several alloys have good sulfide stress cracking resistance at high strength; see A.6.1
Zirconium and tantalum				Resistant to low pH, hot chloride solutions.
Aluminum	pitting, crevice	mercury and copper ions, pH, chloride, temperature	Poor results obtained in geothermal tests.	May be useful as exterior siding and construction material.

FIGURE A.1-1. EFFECT OF OXYGEN ON UNIFORM CORROSION RATE OF 1010 MILD STEEL IN 250°F SEAWATER

Source: George, Manning, and Schrieber 1975

Aeration damage during plant operation can be minimized by guarding against leaks in the lower temperature vacuum sections of the plant. The highest potential for serious damage from aerating is inleakage during plant outages or layups. Stagnant conditions are conducive to crevice and pitting corrosion promoted by oxygen. Oxidation of ferrous ions and hydrogen sulfide in the geothermal fluid can produce ferric ions and local acidity which accelerate attack. Procedures for avoiding damage during shutdowns include draining and rinsing equipment and purging with an inert gas. Oxygen scavengers might be applicable, but possible side reactions with species in the specific fluid should be evaluated.

Flow Rate - The best performance of carbon steels occurs when liquid flow rates are limited to 5 to 7 feet/sec. Localized, uncontrolled flashing in geothermal streams can cause high flow rates (several hundred feet per second) in the system. This action can produce bubbles of non-condensable gas which can cause erosion-assisted corrosion. The relative hardness of particle and metal has little effect on this type of corrosion.

Effects of high velocities are illustrated in Figure A.1.2 for seawater at 250°F.

Failure of components such as pipe ells has occurred in fluids as diverse as those at Salton Sea and Raft River. These failures are probably caused by the flow conditions noted above. Designs to avoid direct impingement on carbon steels and localized flashing should alleviate these types of failures. Providing liquid buffer zones may help. Pump impellers, especially for downhole applications, may be subject to severe cavitation damage. The free carbon dioxide content of many geothermal fluids can cause an apparent vapor pressure that exceeds steam table values by tens to hundreds of psi. Caution on design and material selection is required.

Scaling - Some mechanical protections against uniform corrosion may result from scales formed on steel by precipitation from geothermal fluids, but localized corrosion can also occur under the scales. Scales in geothermal systems are porous and prone to cracking by differential thermal expansion. The exposure of the base metal to a geothermal fluid can lead to local acidity and high chloride concentration similar to conditions during crevice corrosion. Accelerated attack by hydrogen sulfide is increased in such acidic environments.

Attack at small exposed areas can become more serious if the steel is galvanically coupled to a more noble metal. In extreme cases, this concentration of the steel dissolution current can cause rapid perforation of thick-walled steel components.

Chemical cleaning solutions used to remove scale should be evaluated carefully since some types (such as inhibited hydrochloric acid)

FIGURE A.1-2. WEIGHT LOSS CORROSION RATES OF MILD STEEL IN HIGH VELOCITY HIGH TEMPERATURE OXYGEN-FREE SEAWATER

Source: George, Manning, and Schrieber 1975

accelerate corrosion of mild steel. Severe attack can occur if an aggressive cleaning solution is trapped in or under incompletely removed scale.

Galvanic Coupling - Carbon steels will be anodic to stainless steels or nickel, copper, or titanium alloys that may be used for instrumentation, cladding, heat exchanger tubing, and valve and pump trim. Galvanic corrosion of the carbon steel can occur when it is electrically connected to the more noble metal (either directly or through grounding), and when both materials are in contact with the liquid stream. Corrosion will be severe when (1) the dissimilar metals are close together, (2) the conductivity of the solution is high, and (3) the area of steel exposed to the liquid is small compared to that of the more noble metal. Some noble metals are subject to embrittlement when galvanically coupled to steel.

A galvanic series chart obtained for metals in degassed seawater at 225°F is shown in Figure A.1-3. The corrosion rate of the given metal will be accelerated when it is galvanically coupled to a metal with a more positive corrosion potential. A similar order was observed in Heber geothermal fluids during short-term measurements (Syrett et al. 1977). The order of metals in the series may change with variations in chemistry and temperature. If there is doubt, the series should be determined experimentally under field conditions.

Exterior Surfaces - The exterior of mild steel pipes, vessels, and structural components requires protective coatings. Leaks and sprays of saline fluid combined with air and occasional hydrogen sulfide emissions can produce rapid uniform and localized attack. High quality coatings should be specified to avoid localized attack at pores or exposed areas. Protection of the exterior of buried steel components is required to prevent corrosion by groundwater.

Steel Specification - Sulfide SCC and hydrogen blistering can be controlled to a large extent by use of low strength, metallurgically-clean, and void-free steel (see Sections A.1.1.3 and A.1.1.4.). Mill scale left on steel can accelerate pitting or crevice corrosion, especially in the presence of sulfides. Effects of low alloy additions to steel are discussed in Section A.1.1.1.

A.1.1.1. Uniform and Localized Corrosion of Mild Steels

Uniform and localized corrosion are the two main modes of corrosion of low strength, mild steels in geothermal systems. Localized corrosion in this discussion refers to pitting and crevice corrosion.

Uniform corrosion and localized corrosion depend mainly on pH and chloride concentration. Above a critical pH (about 6), uniform corrosion rates are usually less than 10 mpy. The major problem for mild steels is localized corrosion. Since pitting and crevice corrosion are more severe

FIGURE A.1-3. GALVANIC SERIES OF SELECTED ALLOYS IN HOT ACID TREATED/DEAERATED SEAWATER (George, Manning, and Schrieber 1975)

forms of attack than uniform corrosion, carbon and low alloy steels should not be considered immune to attack at high pH values. Chloride ion is the main initiator of localized attack. Hydrogen sulfide can increase the severity of localized corrosion.

Pitting and crevice corrosion are similar with regard to environmental effects and material susceptibility. Both forms of corrosion are most often associated with the localized breakdown of a protective film on the metal surface. A momentary breakdown of this film can result in rapid anodic metal dissolution at the exposed area. The anodic dissolution is driven by cathodic reactions on the rest of the surface. Cathodic reduction of oxygen can supply a high electrochemical driving force. Water or hydrogen ions may also serve as the oxidizing agent, but the driving force is lower, and the exposed area has a better chance to repassivate before growth starts. Once growth starts, the pit or crevice area becomes acidic,

and chloride ions are transported into the area. Both of these effects discourage repair of the protective film, and growth can become self-sustaining.

The growth rate of pits is difficult to predict. If initial testing in a geothermal fluid indicated pit initiation, pit growth rates should be measured periodically during extended testing. It is preferable to find alternate materials.

pH Effects

Low pH affects the uniform corrosion rate of carbon and low alloy steels. This effect is illustrated in Figure A.1-4 for relatively low-temperature, degassed seawater. Acidification of East Mesa Fluid at 300°F from pH 5.7 to pH 4.7 increased corrosion rates by a factor of 3 to 4 (Shannon 1977). The critical pH below which rapid corrosion can occur is in the range of pH 5 to 7. A more accurate general definition of a critical pH is hampered by the following.

- Most pH measurements are made near ambient temperature. The actual pH at high temperatures may be higher or lower depending on the composition of the fluid and on fluid processing.
- Corrosion by dissolved carbon dioxide and hydrogen sulfide is pH-dependent and can change drastically in the range of pH 5 to 7. The equilibria are also temperature-dependent.
- The pH of the liquid in contact with the metal is of primary importance. The pH in crevices, under scale, and near trapped gas can be quite different from bulk liquid pH.

Chloride Effects

The effect of chloride concentration on uniform corrosion of mild steels can be discussed in terms of two main concentration ranges.

- High corrosion rates of mild steels begin to occur at high chloride concentrations (about 10 to 15 percent as sodium chloride).
- Changes in chloride concentration below about three percent (as sodium chloride) have relatively little effect on uniform corrosion rate.

The transition point between these two regions is uncertain, but the chloride concentrations in all known KGRA fluids fall into one of the above two regions.

FIGURE A.1-4. EFFECT OF SEAWATER pH ON THE CORROSION RATE OF 1010 MILD STEEL AT A TYPICAL DEAERATOR TEMPERATURE (George, Manning, and Schrieber 1975)

The increase in corrosion rate with chloride concentrations greater than 6000 ppm is illustrated by the laboratory results in Figure A.1-5. Field corrosion tests in high salinity Salton Sea fluid show mild steel corrosion rates of 40 to 100 mpy. These fluids have a natural pH of about 5.2, but other laboratory tests in high salinity fluids show little change in corrosion rate from pH 5 to 7 (Posey, Palko, and Bacarella 1977). Allowances can be made for uniform corrosion of thick-walled components in high chloride solutions; however, localized corrosion is more likely, and establishing allowances for this corrosion is difficult.

The low sensitivity of uniform corrosion rates in low chloride solutions relative to a high chloride solution is supported by laboratory studies at lower temperature with other variables held constant (Chin and Nobe 1972).

At higher pH, chloride concentration is more critical to pitting and crevice corrosion than to uniform corrosion. Chloride effects on pit initiation can be described by an experimentally-measured electrochemical pitting potential. Pitting is possible if the corrosion potential of a metal exceeds the pitting potential. Therefore, both the corrosion potential and the pitting potential of a metal must be known to make predictions. No standard method has been established for measuring pitting potentials, and reported values vary with experimental techniques. The most active value represents a conservative estimate and should be used at this time. This conservative value is often the "protection potential." An equivalent value found by a metal scratch technique can also be used.

Although these techniques have promise for facilitating future testing, present results are too scarce to do more than illustrate trends. While general trends are probably applicable, crevice corrosion may be initiated more readily than pitting. Most current techniques are less applicable to crevice corrosion. Localized corrosion either under scale or at breaks in scale cannot be predicted from these measurements. Pit growth rate may be proportional to the amount by which the corrosion potential exceeds the pitting potential, but this has received little study.

Variation of corrosion and pitting potentials with chloride concentration at 77°F is illustrated in Figure A.1-6. According to this, steels should be relatively immune to pitting in oxygen-free chloride solutions at 77°F since the corrosion potential is more active (negative) than the pitting potential. The difference is small at higher chloride concentrations, and trace amounts of oxygen could raise the corrosion potential above the pitting potential.

Temperature Effects

Specific effects of temperature on uniform corrosion of carbon steels are difficult to define. This is due to little experimental data in

FIGURE A.1-5. CORROSION RATES OF CARBON AND LOW ALLOY STEELS VS. CHLORIDE CONCENTRATION AT 480°F (Shannon 1980)

NOTE: Total pressure 1000 psig, pH adjusted to 4.5 to 4.8 with carbon dioxide. Oxygen less than 10 ppb.

FIGURE A.1-6. PITTING AND CORROSION POTENTIALS OF STEEL IN OXYGEN-FREE CHLORIDE SOLUTIONS - 77°F

NOTE: Pitting potential curve from an equation by K.J. Vetter (Staehle 1974). Corrosion potentials are representative values. Slope of the corrosion potential line is based on the laboratory measurements of Chin and Nobe (1972).

the 200° to 500°F region. Also, simultaneous changes in the equilibrium distribution of chemical species with temperature may mask the effect of temperature on corrosion kinetics.

Laboratory measurements of the corrosion rate of a carbon steel (ASTM A212B) as a function of pH and temperature are shown in Figure A.1-7. These measurements were made in 4M sodium chloride (approximately 123,200 ppm chloride) without hydrogen sulfide or carbon dioxide (Posey, Palko, and Bacarella 1977).

The addition of bicarbonate and carbon dioxide, two normal corrosive constituents of geothermal fluids, causes a significant change in the corrosion rate as a function of temperature. In these tests, refreshed autoclaves were maintained at a total pressure of 1000 psig. Sufficient carbon dioxide was introduced to maintain a pH of 5.0. Synthetic brines containing 6070 ppm chloride and 133,500 ppm chloride were used (Shannon 1977). Figure A.1-8 shows the corrosion rates of ten carbon steels as a function of temperature in each of the two synthetic brines.

Figure A.1-8 shows that in 6070 ppm chloride synthetic brine with carbon dioxide, the corrosion rate of steel decreases as temperature increases. This decrease is attributed to a transition from ferrous carbonate films at 122°F to more protective magnetite films at higher temperatures. These results are consistent with field experience at Wairakei, New Zealand. It should be noted that most known high temperature geothermal resources have chloride concentrations in the 1000 to 10,000 ppm range, and these results may be applicable to such resources.

The results in the 133,500 ppm synthetic brine are more variable. From 122° to 300°F, all ten steels showed a decrease in corrosion rate. At higher temperatures, some steels showed a large increase in rate while others showed a continued decrease.

Comparison of Figures A.1-7 and A.1-8 shows that the addition of carbon dioxide causes a great change in the corrosion rate of some materials. This suggests that tests in chloride solutions without carbon dioxide species may give misleading results.

Although little data are available, variations in temperature may have as great an influence on pitting as changes in chloride concentration. Figure A.1-9 shows the effect of temperature on the pitting and corrosion potentials in geothermal fluid. Increasing the temperature drastically affects the pitting potential, but the corrosion potential remains relatively constant. Pitting increases as the temperature increases. The end points in Figure A.1-9 at 77°F and 392°F are average values measured in Heber fluid (Syrett et al. 1977). The linear relationships and ranges shown are assumptions. In deaerated seawater the corrosion potential increases above about 250°F (Smith and Compton 1975). In relatively alkaline, low-chloride solutions, the pitting potential may go through a

FIGURE A.1-7. CORROSION RATE OF CARBON STEEL (ASTM A212B) AS A FUNCTION OF CHLORIDE AND TEMPERATURE IN GAS-FREE 4M (APPROXIMATELY 123,200 PPM) CHLORIDE. (Posey, Palko, and Bacarello 1977)

FIGURE A.1-8. CORROSION RATES OF TEN CARBON STEELS IN DEAERATED SODIUM CHLORIDE BRINES AT A TOTAL PRESSURE OF 1000 PSIG. CARBON DIOXIDE PARTIAL PRESSURE SUFFICIENT TO PRODUCE pH 5.0. (Shannon 1977)

FIGURE A.1-9. PITTING AND CORROSION POTENTIALS OF STEEL AS A FUNCTION OF TEMPERATURE IN HEBER GEOTHERMAL FLUID

NOTE: Data at 77°F and 392°F are from Syrett et al. (1977). This graph is for illustration of trends only; linear forms and ranges are assumed for lack of other data.

minimum and then increase (become more positive) at high temperatures (Staehle et al. 1974).

In spite of the variability noted, the results show that temperature can have a substantial effect on susceptibility to localized corrosion.

Effect of Other Key Species on Uniform, Pitting, and Crevice Corrosion of Low Alloy Steels

The key species considered are hydrogen sulfide, carbon dioxide, ammonia, and sulfate. The first three species are of relatively greater importance in condensate streams than in high temperature saline fluids because their effects are not masked by chloride concentrations. Small amounts of oxygen leaked into a geothermal system cause more localized corrosion than the normal environmental factors discussed. Oxygen drastically increases uniform corrosion. This is primarily a design and operation problem in low-pressure equipment and during shutdown.

Hydrogen sulfide in acidic media can greatly accelerate steel corrosion (Makrides and Hackerman 1955; Iofa, Batrakov, and Cho 1964). An iron sulfide layer can form on steels in the presence of hydrogen sulfide, but it offers no real protection against uniform corrosion. If part of the layer flakes off, the exposed steel is subject to localized corrosion accelerated by galvanic coupling to the cathodic iron sulfide layer. The exposed area may also become locally acidic, allowing increased hydrogen sulfide attack. Crevice or pitting corrosion initiated by other means may be accelerated by hydrogen sulfide, which stimulates the anodic dissolution reaction.

Dissolved carbon dioxide indirectly affects corrosion by the buffering actions of the aqueous species carbonic acid, bicarbonate, and carbonate. Release of carbon dioxide during flashing increases the pH of the flashed fluid. Maintaining carbon dioxide pressure while cooling geothermal fluids may decrease pH due to the temperature dependence of the equilibrium constants. In mildly acidic solution (pH about 3 to 5), carbon dioxide accelerated the uniform corrosion of mild steels. Results obtained in one percent sodium chloride and 0.78 to 14.696 psia carbon dioxide up to 176°F dictate that this effect is due to acceleration of the cathodic (hydrogen evolution) reaction (deWaard and Milliams 1975).

Ammonia dissolved in geothermal fluid tends to neutralize the acidity produced by carbon dioxide and hydrogen sulfide, but the acidic species are present in much larger amounts than ammonia in most geothermal sources. Limited seawater desalination tests showed that the uniform corrosion rate of mild steels increased approximately 65 percent when 15 ppm ammonia (in solution) was added as ammonia gas (George, Manning, and Schreiber 1975).

When the chloride ion concentration is low, sulfate becomes the main aggressive ion affecting uniform corrosion of mild steels. Sulfate is much less aggressive than chloride in promoting pitting or crevice corrosion.

Effect of Low Alloy Addition

In moderate chloride and pH systems, the uniform corrosion rates of low alloy steels are somewhat lower than those of low carbon steels, but the absolute difference is usually small. Pitting and crevice corrosion in low alloy steels are similar in nature to the types of corrosion in mild steels, and sometimes more severe. High-strength, low alloy steels are more susceptible to stress corrosion cracking by either sulfide or chloride.

Identification of corrosion-resistant, low alloy steels may be necessary for utilization of high-chloride, low-pH geothermal fluids. These fluids cause high corrosion rates of carbon steels. Pitting and crevice corrosion of low alloy steels in these environments are major concerns.

The limited success to date in moderate salinity-pH fluids should not preclude further testing of low alloy steels. Long-term tests in a seawater boiler at about 392°F showed that steels containing 0.2 percent to 0.3 percent copper had lower pitting rates than plain steels (Butler and Olson 1957). Since little is known about long-term pitting rates in geothermal fluids, comparative testing of plain carbon and copper or other low alloy steel for extended periods is of interest.

Extensive seawater desalination testing of low alloy steels showed that they were seldom worth the additional cost (George, Manning, and Schrieber 1975). A possible exception was Cor-Ten steel at high fluid velocities. This alloy was tested at Raft River with limited success, but more extensive testing is desirable.

A.1.1.2 Chloride-Stress Corrosion Cracking of Low Alloy Steels

Stress corrosion cracking of low alloy steels by chloride ions (chloride-SCC) in hydrogen sulfide-free solutions has been observed at low pH. (Baker and Singleterry 1972; Hudgins 1966). This corrosion should not be a major problem in the usual range of geothermal environments, but in-situ cracking tests should be conducted. It could be a more severe problem in acidified streams. See Table A.1-1, left column, for characteristics of chloride-SCC.

A.1.1.3 Sulfide Stress Cracking of Low and Middle Alloy Steels

Sulfide stress cracking (SSC) is the brittle failure of hard, high-strength alloys when they are exposed under stress to environments

TABLE A.1-1. COMPARISON OF CHLORIDE-SCC AND SSC IN GEOTHERMAL ENVIRONMENTS^a

CHLORIDE-SCC	SSC
1. mechanism: active path dissolution (rapid metal dissolution at crack tip)	1. mechanism: cathodic hydrogen embrittlement
2. promoting species: usually chloride ion	2. promoting species: hydrogen sulfide in aqueous solution
3. austenitic steels most sensitive	3. martensitic and ferritic steels most sensitive; austenitic steels immune
4. <u>not</u> notch sensitive	4. notch sensitive
5. severity increases with increasing temperature	5. severity decreases with increasing temperature
6. ppm oxygen causes drastic increase in severity of attack	6. ppm oxygen has little if any effect on severity of attack
7. bulk pH has little effect	7. low pH greatly accelerates failure
8. no threshold stress	8. threshold of applied stress below which failure does not occur
9. failure is sudden, catastrophic fracture	9. failure is sudden catastrophic fracture

^aIn this document, chloride stress corrosion cracking (chloride-SCC) and sulfide stress cracking (SSC) are considered to be subsets of stress corrosion cracking. Stress corrosion cracking is a general term which includes any environmental fracture of metal under static tensile stress.

containing even small amounts of sulfide in an aqueous phase. Often these environments are not particularly severe from a uniform or localized corrosion standpoint. The failure is sudden and catastrophic. There is little or no evidence of metal loss. See Table A.1.1, right column, for characteristics of SSC.

SSC has been a problem at the Wairakei, New Zealand, (Fooks 1964; Foster, Marshall, and Tombs 1964; Marshall and Tombs 1969; Smith 1964), and Cerro Prieto, Mexico, (Mercado, A. 1976) power plants. It places definite restrictions on materials and design for any geothermal resource containing hydrogen sulfide. These limitations are the result of a complex interaction of environmental and material factors. Resistance to SSC generally increases with increasing temperature, decreasing stress, decreasing yield strength, decreasing hydrogen sulfide concentration, and increasing pH. The effects of sulfide concentration, pH, stress, and yield strength are interdependent and more significant than other factors, such as microstructure and alloy composition.

Effect of Hydrogen Sulfide Concentration

The failure (cracking) of stressed materials in high hydrogen sulfide environments (above 15 to 30 ppm) either occurs within days or not at all. At concentrations less than 3 ppm, considerably longer times to failure are observed, and the incubation time may approach the service life of the metal (Hudgins et al. 1966; Hudgins 1969). Concentrations of hydrogen sulfide as low as 20 ppb accelerate hydrogen entry into steel (Hudson et al. 1968). Concentrations less than 0.1 ppm have caused failure in long-term tests.

Effect of Stress and Yield Strength (Hardness)

SSC is stress dependent. The total stress to which the steel is subjected must be considered. Total stress includes (1) applied tensile stress; (2) residual tensile stresses resulting from phase transformation during or after heat treatment; (3) thermal stress; and (4) cold deformation during fabrication and service (Bates 1969; Hudgins et al. 1966; NACE 1975; Vollmer 1958). Even one percent cold work can lower the threshold stress about 30 percent (Baldy 1961). (Threshold stress is the greatest applied stress which does not cause SSC failures.) Cold-worked parts should be heat-treated to relieve residual stress. A notch greatly reduces threshold stress and greatly increases the effect of applied stress.

Yield strength (YS) and microstructure are the most important material factors in SSC. Yield strength or hardness is the standard criterion for SSC susceptibility. The threshold stress decreases as the YS of the steel increases, as shown in Figure A.1-10.

12-80-0705

FIGURE A.1-10. APPROXIMATE CORRELATION OF HARDNESS, TIME TO FAILURE AND APPLIED STRESS FOR CARBON STEELS (3000 PPM HYDROGEN SULFIDE IN 5 PERCENT SODIUM CHLORIDE) (Hudgins 1969)

Interaction of Hydrogen Sulfide Concentration, Stress, and Yield Strength

The National Association of Corrosion Engineers (NACE) standard for sour (hydrogen sulfide) service is 90 to 100 ksi yield strength, or HRC 22. This is based on performance of steels stressed to 100 percent YS in NACE solution (5 percent sodium chloride, 0.5 percent acetic acid, and saturated with hydrogen sulfide) (NACE 1977).

The actual limitations on usable hardness are a complex interaction of yield strength, applied stress, temperature, and concentration of hydrogen sulfide. Figure A.1-10 shows the effect of limiting applied stress on allowable hardness.

While a given steel may be utilized at much greater yield strength and hardness (approximately 128 ksi, HRC 30) if stresses are limited to 60 percent of yield, calculation shows that the point of maximum return on usable strength is exceeded (Hudgins et al. 1966).

Figure A.1-11 illustrates the increase in allowable hardness with decreasing hydrogen sulfide concentrations.

Effect of Microstructure and Composition

Strength and hardness are inadequate for defining susceptibility to SSC (Bowers, McGuire, and Wiehi 1952). Microstructure affects the SSC resistance of steels with the same hardness, while composition is significant only as it affects hardening and microstructure (Fraser and Greer 1976; Hudgins et al. 1966; Snape 1967, 1968). Quenched and tempered steels are superior to normalized and tempered steels of comparable yield strengths (Snape 1967). Normalized and tempered steels are superior to normalized steels (Kane and Greer 1976). Figure A.1-12 illustrates the superiority of quenched and tempered steel over normalized and tempered steels.

The most resistant microstructures consist of relatively fine, spheroidized carbides uniformly dispersed in ferrite. This is typical of martensite tempered at high temperature. Steels high in chromium, sulfur, or phosphorus are less resistant (Snape 1968).

The next most resistant microstructures contain coarse globular and/or laminar carbides (Snape 1968). Sulfur also tends to form "stringers" of inclusions which favor cracking (Okhi et al. 1977). Laboratory heats of very low sulfur steels or steels with trace lanthanide additions are very resistant to SSC (Okhi et al. 1977; Snape 1968; Troiano and Hehemann 1978).

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FIGURE A.1-11. APPROXIMATE CORRELATION OF FAILURE TIME FOR CARBON STEELS IN 5 PERCENT SODIUM CHLORIDE CONTAINING VARIOUS CONCENTRATIONS OF HYDROGEN SULFIDE (Hudgins 1969)

FIGURE A.1-12. YIELD STRENGTH-THRESHOLD STRESS RELATIONSHIP FOR LOW ALLOY STEELS (Snape 1967)

In the region below and left of the shaded areas, no failures occurred. Above and right of the shaded areas, all specimens failed. In the shaded area, some steels were susceptible, some were resistant.

Microstructures containing untempered martensite have the least resistance of all. Even very small traces of untempered martensite, especially as a network, drastically lower the threshold stress. Such steels fail at hardnesses far below HRC 22. These microstructures can occur in either quenched-and-tempered or normalized-and-tempered steels if the tempering temperature exceeds the lower critical temperature (austenizing temperature). Additions of nickel and manganese reduce the lower critical temperature, which increases the risk of forming untempered martensite. This accounts for the poor performance of steels containing more than one percent nickel (NACE 1975). Low alloy steels containing more than one percent nickel should be tested carefully before use. Additions of chromium and molybdenum worsen the situation because higher tempers are required to get the desired low yield strengths.

Effect of Temperature

The resistance to SSC of high strength, low alloy steels increases as temperature increases (Grudger 1974; Troiano and Hehemann 1976, 1978), but there is no temperature above which immunity occurs. Table A.1-2 shows the effect of increasing the temperature on the usable YS of a number of alloys.

Effect of pH

SSC usually occurs in acidic solutions. The severity of cracking in solutions below pH 4.5 is relatively constant. Between pH 4.5 and 6, there is a moderate decrease in severity. Resistance to SSC increases rapidly above pH 6, but SSC has been observed at pH 12 (Troiano and Hehemann 1978).

Effect of Chloride, Moisture, and Oxygen

Chloride ions are not required for SSC (Baldy 1961; Troiano and Hehemann 1978), but they increase the severity of SSC in steels containing chromium. Little difference in SSC susceptibility was observed in hydrogen sulfide-saturated, chloride-free solutions, compared to 30,000 ppm-chloride solutions and 120,000 ppm-chloride solutions saturated with hydrogen sulfide (Troiano and Hehemann 1978). That chloride affects SSC resistance at low hydrogen sulfide concentrations has not been determined.

Laboratory tests (Fraser and Treseder 1952; Smialowski 1962) and Wairakei field data (Marshall and Tombs 1969) confirmed that liquid water is required for SSC. Dry steam containing hydrogen sulfide does not appear to be active, but SSC may occur at any location where this steam condenses.

Oxygen has a negligible effect on SSC.

TABLE A.1-2. SULFIDE STRESS CRACKING OF SOME HIGH STRENGTH ALLOYS

ALLOY TESTED ^a	YIELD STRENGTH (ksi)	NO. SAMPLES FAILED/NO. SAMPLES TESTED							
		LOW CHLORIDE ENVIRONMENT ^b				HIGH CHLORIDE ENVIRONMENT ^c			
		Ambient Temp.	212°F	325°F	425°F	Ambient Temp.	212°F	325°F	425°F
AISI 4118	120	1/1	---	---	---	---	---	---	---
	108	1/2	---	---	---	---	---	---	---
	95	0/3	---	---	---	---	---	---	---
AISI 4123 ^d	131	---	0/1	---	---	2/2	---	0/1	---
	123	---	---	---	---	1/1	---	---	---
	119.5	---	---	---	---	0/1	---	---	---
AISI 4130	138	1/1	0/1	---	---	---	---	---	0/1
	128	4/4	0/3	0/1	---	---	---	0/1	0/1
	123	2/3	0/2	0/1	---	1/2	0/1	0/1	0/1
	119.5	2/3	0/2	0/2	---	0/3	0/1	---	---
	107.5	0/2	---	---	---	---	---	---	---
AISI 4130(VLS) ^e	145	---	---	---	---	1/1	---	---	---
	138	---	---	---	---	1/1	---	---	---
	136	---	0/1	---	---	0/1	---	---	---
	128	---	---	---	---	0/1	---	0/1	---
	123	---	---	---	---	0/1	---	---	---
AISI 4135 Mod	150	---	1/1	---	---	---	---	0/1	0/1
	138	5/5	0/1	0/3	---	2/2	---	---	---
	125	5/8	1/3	0/2	---	2/3	0/1	---	---
	116	0/4	---	---	---	---	---	---	---
	110	0/4	0/2	---	---	0/1	0/1	---	---
Armco V1312 ^d	136.5	0/1	---	---	---	1/1	---	---	0/1
	116	---	---	---	---	0/1	---	---	---
Armco V1313 ^d	143	1/1	---	---	---	2/2	---	---	1/1
	125.5	---	---	---	---	0/1	---	0/1	---

^aSpecimens stressed 90 to 100 percent yield strength and exposed for 30 days, unless otherwise indicated.
See Appendix G for alloy compositions

^b5% sodium chloride + 0.5% acetic acid + 3000 ppm hydrogen sulfide

^c20% sodium chloride + 0.5% acetic acid + 3000 ppm hydrogen sulfide

^dExposed for ten days

^eSpecial very low sulfur heat

Source: Troiano and Hehemann 1976

TABLE A.1-2. (Continued)

ALLOY TESTED ^a	YIELD STRENGTH (ksi)	NO. SAMPLES FAILED/NO. SAMPLES TESTED							
		LOW CHLORIDE ENVIRONMENT ^b				HIGH CHLORIDE ENVIRONMENT ^c			
		Ambient Temp.	212°F	325°F	425°F	Ambient Temp.	212°F	325°F	425°F
2Cr-1.0Mo	130	2/2	---	---	---	---	---	---	---
	118	1/1	---	---	---	---	---	---	---
	105	0/4	---	---	---	0/1	---	---	---
3Cr-1.0Mo	154	1/1	---	---	---	---	---	---	---
	130	1/1	---	---	---	---	---	---	---
	115	1/1	---	---	---	---	---	---	---
	100	0/2	---	---	---	---	---	---	---
AISI 301	160	---	---	0/1	---	---	---	---	---
AISI 304	40	---	---	0/1	---	---	---	---	---
	130	---	---	0/1	---	---	---	---	---
AISI 310	30	---	---	0/1	---	---	---	---	---
	70	---	---	0/1	---	---	---	---	---
ASTM A-286	190	---	0/1	1/1	---	---	---	---	3/4
	165	---	---	0/1	---	---	---	---	1/1
	155	---	---	---	---	---	---	---	0/2
Monel K500	170	0/1	---	---	---	---	---	---	0/1
	140	---	0/1	---	0/2	---	---	---	0/2
MP35N	220	0/1	---	---	0/1	---	---	---	0/2

^aSpecimens stressed 90 to 100 percent yield strength and exposed for 30 days, unless otherwise indicated
See Appendix G for alloy compositions

^b5% sodium chloride + 0.5% acetic acid + 3000 ppm hydrogen sulfide

^c20% sodium chloride + 0.5% acetic acid + 3000 ppm hydrogen sulfide

Source: Troiano and Hehemann 1976

A.1.1.4 Hydrogen Blistering of Mild Steels

Hydrogen blistering occurs in low strength steels exposed to aqueous solutions containing hydrogen sulfide and has been a problem at the Wairakei geothermal plant (Marshall and Tombs 1969).

In short-term laboratory tests, hydrogen sulfide partial pressures of about 0.02 psia (approximately 60 ppm in solution) were required for hydrogen blistering of iron (Greco and Wright 1962). In long-term tests (greater than 200 days) of cold-rolled 1036 carbon steel, 1.0 ppm hydrogen sulfide in solution caused blistering while 0.1 ppm did not (Hudgins et al. 1966).

Voids are required for blistering, and "killed" (void-free) steels resist blistering. Though not necessarily subject to blistering, voids in welds may accumulate molecular hydrogen and burst. Stress is not required for hydrogen blistering. The equilibrium pressure between atomic and molecular hydrogen trapped in a void is believed to be on the order of 1.5 million psi, enough to rupture any known engineering material (Fontana and Greene 1967).

A.1.2 Corrosion of Mild and Low Alloy Steels in Geothermal Steam

Steam from liquid-dominated geothermal fluids has corrosion characteristics of its own, but corrosiveness is dominated by two properties common to the saline fluid and condensate streams.

- Carryover of entrained liquid provides the chloride needed for localized attack. High-velocity impingement of droplets is conducive to localized attack. Efficient steam separation and steam scrubbing are important, but may not preclude attack. For a given steam, corrosiveness may depend on the chloride content and corrosiveness of the liquid stream, despite efficient separation and scrubbing.
- Areas where local condensation may occur are subject to attack by low pH condensate containing hydrogen sulfide, carbon dioxide, and some chloride. Most noteworthy of these locations are the low pressure turbine section, liquid traps, and poorly insulated or stagnant parts of steam transfer sections. The latter should be eliminated by design.

A.1.2.1 Uniform and Localized Corrosion of Low Alloy Steels in Geothermal Steam

With the exception of separated steam at the Salton Sea, uniform corrosion rates in geothermal steam are typically less than 10 mpy. The

reason for high corrosion rates in Salton Sea steam is unclear. One possible explanation may be the entrained liquid. Each entrained liquid drop contains essentially the same high chloride concentration as the wellhead liquid. The metal surfaces in the steam flow are exposed to these chloride concentrations in impinging droplets. The low chloride contents quoted for the steam phase may be misleading.

Steam scrubbing can reduce the number of drops but not the chloride concentration of each drop; little reduction in corrosion rate was found after steam scrubbing. It is also noteworthy that the localized corrosion susceptibility of resistant alloys is similar in Salton Sea wellhead liquid, separated steam, and scrubbed steam.

A.1.2.2 Corrosion Fatigue in Low Alloy Steels

Although corrosion fatigue occurs in both steam and liquid media, this failure mode is discussed here because turbines operating in geothermal steam are subject to both environments. Turbines are the most important (expensive) components in a geothermal plant that will be subject to corrosion-fatigue.

Metals under cyclic loading fail at stresses far below those stresses that characterize their normal mechanical properties. When this phenomenon occurs in "inert" environments (i.e., air), it is called fatigue. When the applied stress range is plotted against the logarithm of the number of cycles to failure (S/N plot), the cycle-to-fail curve becomes asymptotic to a limiting value of stress. Below this stress there will be no failure, whatever the test length. This is the "fatigue limit" or "fatigue strength" (Gilbert 1956; Wescott 1938).

When the metal is exposed to a corrosive environment while under cyclic stress, the S/N graph never becomes asymptotic to the zero stress line. The corrosion fatigue limit (or fatigue endurance limit) is the greatest unit stress which may be applied under given conditions of stress, rate of stress application, temperature, and corrosive environment without causing failure in a given number of cycles of stress (Westcott 1938). The values for corrosion-fatigue limits are useless, except for comparison within one set of tests, unless the number of cycles and cycle rate are given.

The combined effects of cyclic stress and corrosion are often far more severe than the simple sum of their actions.

Based on tests of two alloys at Cerro Prieto, Mexico, corrosion-fatigue of low alloy steels is a significant factor in material selection and design. After 150 days' exposure to nonaerated steam, the reduction in fatigue endurance limit (FEL) of 1Cr-1.3Mo-0.25V (RHB approximately 64) was 27.8 percent, while 3.5Ni-1.75Cr-0.4Mo-0.1V (RHB approximately 68) showed a

38.6 percent reduction of FEL. These specimens were not under cyclic stress during exposure. Cyclic loading during exposure would have caused greater loss of endurance.

Fatigue tests of 2.5Ni-Cr-Mo-V motor alloy in geothermal steam at Otake indicate a reduction in FEL of 41.4 percent at 100 million cycles of stress. These specimens were cyclically loaded during exposure to the environment. Geothermal steam (at Otake) caused much more serious corrosion-fatigue than boiler quality steam. In boiler quality steam, the reduction in FEL for 2.5Ni-Cr-Mo-V was 16.1 percent at 10 million cycles of stress and 17.2 percent at 100 million cycles of stress.

Tests on carbon steels and low and middle alloy steels in fresh, salt, and seawater show that endurance limits in a moderately corrosive medium (i.e., saltwater) are practically independent of the chemical composition of the steel (Mehdizadeh, McGlasson, and Landers 1966).

A series of corrosion-fatigue tests was done in a solution containing 35,400 ppm chloride with additions of carbon dioxide, hydrogen sulfide, and oxygen. AISI 1035 specimens were stressed 10 million cycles at 10 Hz (Mehdizadeh, McGlasson, and Landers 1966). Chloride had no significant effect on the fatigue endurance of low alloy steels. In a neutral, air-free (less than 0.1 ppm oxygen) solution, the FEL (compared to the FEL in air) increased slightly. Addition of 3000 ppm hydrogen sulfide to the chloride solution lowered the pH to 4.5. The endurance limit decreased 20 percent and cracking and hydrogen blistering occurred.

The effect of hydrogen sulfide on harder materials may be much more severe. These materials are cold-worked under cyclic stress and may become susceptible to SSC as well as corrosion fatigue.

Addition of 700 to 800 ppm carbon dioxide and 250 to 300 ppm bicarbonate to the chloride solution reduced the pH to 5.5 and reduced the FEL 41 percent. Many cracks were observed. Although carbon dioxide does not cause SCC of statically loaded materials, it appears to be an effective cracking agent when combined with cyclic stress.

The combined effect of carbon dioxide and hydrogen sulfide is worse than the sum of their actions. In a chloride solution containing 700 to 800 ppm carbon dioxide and 60 to 70 ppm hydrogen sulfide, FEL decreased 62 percent. Both pitting and surface cracking were observed.

The addition of less than ten ppm oxygen drastically reduced the FEL in the chloride solution (65 percent reduction). Addition of three ppm oxygen doubled the reduction in FEL in the chloride/hydrogen sulfide solution, but caused little, if any, increase in damage in the chloride/carbon dioxide solution.

A.1.2.3 Erosion-Corrosion in Steam Lines

Exfoliation of iron sulfide scales from steam lines is another potential source of damage to turbines operating directly on flashed steam. Iron sulfide coatings form on steel pipes carrying steam containing hydrogen sulfide. There is a tendency for these coatings to crack and flake off. If this occurs in lines upstream of the turbine, the scale particles can be carried to the turbine, causing erosion and possibly erosion-corrosion damage. This problem has been reported at the Cerro Prieto geothermal plant.

A much slower exfoliation of magnetite scales has caused serious damage to turbines in high temperature-high pressure fossil fuel plants. In most cases, no damage was noted until the plant was ten to fifteen years old. This experience points out the need for close monitoring and frequent inspection of geothermal turbines.

A.1.3 Corrosion of Mild and Low Alloy Steels in Condensate Streams

The corrosivity of condensate streams depends to a large extent on the following factors:

- efficiency of steam separation and thus the chloride content of the condensate,
- quantity of the flashed noncondensable gases (carbon dioxide, hydrogen sulfide, and ammonia) which are absorbed by the condensate,
- pH of the condensate resulting from absorption of the above gases, and
- aeration or mixing with aerated water.

These factors are interactive. Higher chloride concentrations can be tolerated if the condensate is not aerated. The pH of the condensate depends primarily on the amount of acidic carbon dioxide and hydrogen sulfide absorbed relative to basic ammonia. The pH in turn determines the corrosiveness of dissolved hydrogen sulfide and carbon dioxide in contact with mild steels. For most sources, the ammonia concentration is low compared to carbon dioxide and hydrogen sulfide concentrations, and the condensate pH will be fairly low.

Previous sections can be consulted for discussion of the effects of pH, hydrogen sulfide, carbon dioxide, ammonia, and oxygen. Serious corrosion problems have occurred in the aerated condensate/cooling water systems of several operating geothermal plants. Although condensate

streams have relatively low chloride concentrations, their potential corrosivity should not be underestimated. Even with very efficient (99.5 percent) steam separation, the chloride content of the condensate can be high enough to cause problems. For example, assuming 25 percent flashing of a wellhead liquid containing one percent chloride and 0.05 percent liquid carryover, the condensate would contain about 20 ppm chloride. This is approximately equal to the minimum chloride concentration needed to cause pitting of plain steels at 77°F (Szklańska-Smiałowska 1971).

A.2 Stainless Steels

The uniform corrosion rate of most stainless steels is low (less than 0.5 mpy) in geothermal fluids, but many are subject to the more serious forms of corrosion: pitting, crevice corrosion, stress corrosion cracking (SCC), sulfide stress cracking (SSC), intergranular corrosion, and corrosion-fatigue. Stainless steels have been used in geothermal environments, but care must be taken in their selection and application.

400 Series Ferritic and Martensitic Steels - These materials have poor resistance to hot geothermal liquids. The martensitic steels AISI 410 and 440, often used as pump shafts, suffered deep pitting and severe crevice corrosion in Raft River tests (Miller 1977). Similar materials have been used with more success in geothermal steam. The 400 series ferritics may be applied in low-chloride systems, but testing is required.

Higher Alloy Ferritic Stainless Steels - The newer ferritic alloys are much less susceptible to SCC than the more common austenitics. The 26Cr-1Mo alloy has shown promise in field tests at East Mesa and in deaerated flowing seawater. The molybdenum content of this alloy may not be high enough to withstand crevice corrosion in scaling environments or in applications where periodic aeration is possible. The higher alloy, high-purity ferritics, 29Cr-4Mo and 29Cr-4Mo-2Ni, generally have outstanding resistance to geothermal environments. These materials can be considered for all applications where their mechanical properties are acceptable. The nickel-containing alloy normally has slightly better resistance to uniform corrosion, but is more susceptible to SCC than the nickel-free alloy.

Austenitic Stainless Steels - Susceptibility to chloride-SCC may limit the use of austenitic stainless steels in geothermal liquids (see Section A.2.1.2).

Lower alloy austenitic alloys are also susceptible to pitting and crevice corrosion. AISI 304 generally has the lowest resistance; the addition of molybdenum significantly improves resistance. AISI 316 with two to three percent molybdenum has much better resistance to pitting and crevice corrosion than AISI 304, but AISI 316 is susceptible to corrosion in geothermal fluids, especially to crevice corrosion.

AISI 317 with four percent molybdenum has significantly better corrosion resistance to localized corrosion and chloride-SCC than either 304 or 316. Further testing of AISI 317 in geothermal fluids is required.

The high alloy austenitics are significantly more resistant to localized corrosion and somewhat more resistant to SCC than the 300 series, but they are not immune to attack. Members of this class include Alloy 20-Cb3, Allegheny-Ludlum 6X, and Haynes Alloy 20 mod. The extra cost of these materials should be weighed against that of materials such as the 29Cr-4Mo ferritic alloys, titanium alloys, Inconel 625, and Hastelloys, which may give better overall corrosion performance in many applications.

Cast Stainless Steels - Susceptibility of these metals to corrosion is determined primarily by the chemical composition of the alloy. They are usually equivalent to comparable wrought alloys. Cast alloys are usually used for pumps and valves which contain numerous locations for crevice corrosion.

A.2.1 General Guidelines for Use of Stainless Steels

Aeration - Many stainless steels which could perform well in oxygen-free geothermal environments are subject to severe pitting and crevice corrosion in the presence of small quantities of oxygen. SCC of commonly used austenitic stainless steels in high temperature chloride solutions can occur minutes after introducing oxygen in ppm quantities or less. This failure is often catastrophic. Other alloys are more resistant. Pits, crevice attack, or cracks initiated during upset or plant outages can continue to grow once normal operation is resumed. Special care should be taken during plant commissioning because of the likelihood of unstable conditions.

Flow Rate - Stainless steels are more resistant to high velocities than plain and low alloy steels. Continuous high velocity flow is more desirable than low flow rates or stagnant conditions. Under stagnant conditions, settling of entrained solids or spot deposition of loose scale can lead to crevice corrosion. Stagnant conditions should be avoided, and stainless steel components should be drained and rinsed during plant shutdown. Resistance to erosion-corrosion is more closely related to uniform corrosion resistance than hardness of the metal.

Scale - Local concentration cells can develop under porous or cracked scale on stainless steel and lead to crevice corrosion to which stainless steels are susceptible. After an attack is initiated, local increases in acidity and chloride concentration cause intense corrosion.

Welding - Good welding procedures are important to the successful use of stainless steels. Sensitization to intergranular corrosion by welding is discussed in Section A.2.3. Physically poor welds may have

crevices that are susceptible to crevice corrosion. SCC may initiate at pits close to poor welds.

Exterior Surfaces - Measures should be taken to protect the exterior of stainless steel components that are exposed to air. Leaks and splashes of hot chloride solutions combined with the high oxygen content of air can subject these components to chloride-SCC conditions. Flange leaks leading to conditions in which geothermal fluid concentrates and dries under insulation can be dangerous. Nonporous gaskets are required to guard against cracking at flanges.

A.2.1.1 Pitting and Crevice Corrosion of Stainless Steels

Pitting and crevice corrosion are the main problems for stainless steels which are resistant to chloride-SCC. Crevice corrosion is often the more serious problem since stainless steels are frequently used in complex equipment where crevice attack is more readily initiated.

The pitting potentials (see Section A.1.1.1) of stainless steels are generally much more noble (positive) than plain steels. They should be more resistant to localized attack. However, the corrosion potentials of stainless steels are also more noble, and it is the difference between the pitting potential and the corrosion potential which is important (Section A.1.1.1). Corrosion potentials of passive stainless steels can be made more noble by small quantities of oxidizing agents present in the environment. This increase can result in rapid localized attack.

Effect of Chloride

Stainless steels become more susceptible to localized corrosion as the chloride concentration increases. This dependence is shown in Figure A.2-1 for AISI 304 stainless steel.

This logarithmic dependence has been measured for other stainless steels (Johnson 1972; Lackie and Uhlig 1966; Suzuki and Kitamura 1972). Chloride dependence data at geothermal temperatures are not available.

Effect of pH

According to low temperature studies, pH has little influence on pitting potentials over the pH range of major interest (4 to 9) for geothermal systems. The pH effect on corrosion potential is also small in this region.

Laboratory tests with several stainless steels in Heber geothermal fluid at 392°F show a slight noble shift in pitting potential as the pH (measured at room temperature) was increased from 5.3 to 7 (Syrett

FIGURE A.2-1. EFFECT OF CHLORIDE ION ACTIVITY ON STEADY-STATE CRITICAL POTENTIAL FOR PITTING, 77°F (Lackie and Uhlig 1977)

et al. 1977). The corrosion potentials also shifted in the noble direction by about the same amount, so there is little change in pitting tendency.

Effect of Temperature

Temperature has a major effect on the localized corrosion of stainless steels. Most studies of the temperature dependence of pitting were at less than 212°F. Pitting susceptibility increases with increasing temperature, as indicated by a shift in pitting potential to more active values. An initial rapid decrease in pitting potential is often followed by a much slower decrease or nearly constant value at higher temperatures. Studies at 300° to 482°F indicate that resistance to pitting may increase with increasing temperature in this range. Morphology of pit growth changes at elevated temperatures; the trend is to the formation of a larger number of smaller pits.

Examples of pitting and corrosion potential behavior at high temperatures in 123,200 ppm-chloride solution are shown in Figure A.2-2. The region near 200°F may actually be more dangerous than at higher temperatures. In this high-chloride fluid, the difference between pitting and crevice corrosion potentials is small for AISI 304 and AISI 316. Pitting or especially crevice corrosion could occur in the presence of small amounts of oxidizing agents. Similar increases in pitting potential occur for metals at 212° to 437°F in pH 9 solution with low chloride concentrations (Spaepen and Fevery-DeMeyer 1967; Staehle et al. 1974). The decrease in pitting tendency at high temperatures shows that materials should be tested near the temperature at which they are used, even if it is lower than the wellhead temperature.

Pitting kinetics have been studied over a limited temperature range (77° to 122°F) for 18Cr-12Ni-2Mo-Ti in 0.1N (170 ppm) hydrogen sulfide-0.5M sodium chloride (17,725 ppm chloride) at constant potentials. The number of pits increases with increasing temperatures (Szkarska-Smialowska 1972). Established pits grow more slowly at higher temperatures since the current density within each pit is relatively low. Similar effects were noted for pits growing in ferric chloride solution without an externally applied potential. This is said to be due to distribution of the cathodic current over a larger number of pits.

Effects of Other Species

Stainless steels are generally resistant to corrosive attack by contaminated seawater containing hydrogen sulfide and ammonia (George, Manning, and Schrieber 1975). Stagnant conditions should be avoided. Hydrogen sulfide may cause pitting of AISI 316 in acidic solutions by retarding the formation of passive films and causing localized attack in regions of low pH (IJzermans and Der Krogt 1968).

FIGURE A.2-2. PITTING POTENTIALS AND CORROSION POTENTIALS OF TYPES 304 AND 316 STAINLESS STEEL IN 123,200 ppm CHLORIDE SOLUTION AS A FUNCTION OF TEMPERATURE (Posey, Palko, and Bacarella 1977)

No direct evidence for the effect of carbon dioxide on the pitting of stainless steels was found in the literature. High concentrations of dissolved carbon dioxide in fairly acidic solutions can catalyze the hydrogen evolution reaction. Pitting of alloys with pitting potentials more active than the hydrogen equilibrium potential could be accelerated by carbon dioxide in fairly acidic solutions. Bicarbonate may function as a pitting inhibitor at high concentration in alkaline solution.

Sulfate can inhibit the pitting of stainless steels in chloride solution. The minimum sulfate activity needed to inhibit pitting of AISI 304 at 77°F depends on chloride concentration. Approximately 0.08M sulfate is needed for 0.1M chloride (about 2.7 ppm sulfate per ppm chloride); such ratios of sulfate and chloride are rarely found in higher temperature geothermal fluids.

Effect of Chromium and Molybdenum

The pitting and crevice corrosion resistances of stainless steels are strongly dependent on the chromium and molybdenum contents. These effects were explored in a program to develop ferritic stainless steel condenser tubes for use in multi-stage, flash evaporation, desalination plants (Pessall and Nurminen 1974). Pitting potentials by the scratch method were determined in deaerated artificial seawater at 194°F and pH 7.2.

Results are shown in Figure A.2-3 for critical pitting potential as a function of chromium + molybdenum added (Pessall and Nurminen 1974). The strong influence of molybdenum addition is apparent. Results for commercial alloys containing nickel show that their resistance is due primarily to their chromium + molybdenum content and not to nickel content. Some beneficial effects of silicon + nickel addition were noted.

Crevice corrosion results in aerated synthetic seawater at 250°F are given in Figure A.2-4. This is a very severe environment, and the equal corrosion regions give a graphic representation of alloy behavior. Severe crevice corrosion tests applied to a number of alloys show that at least two to three percent molybdenum is needed for good crevice corrosion resistance regardless of alloy system (Lizlovs 1977).

A.2.1.2 Chloride-Stress Corrosion Cracking of Stainless Steels

Stress corrosion cracking (SCC) promoted by chloride ion (chloride-SCC) is a severe threat in geothermal systems; austenitic steels are the most vulnerable.

Austenitic stainless steels are susceptible to chloride-SCC in hot chloride solutions. Since chloride-SCC is a catastrophic type of failure, the use of austenitics in geothermal streams requires careful

FIGURE A.2-3. COMPARISON OF THE CRITICAL PITTING POTENTIALS OF Fe-Cr-Mo ALLOYS WITH SEVERAL COMMERCIAL ALLOYS IN DEAERATED SYNTHETIC SEAWATER 195°F, pH = 7.2 ± 0.2 (Pessal and Nurminen 1974)

evaluation. Chloride-SCC depends on chloride, oxygen, pH, temperature, stress, and alloy composition. These factors are discussed below.

Ferritic stainless steels are generally much more resistant to chloride-SCC than are austenitic stainless steels. Some are susceptible to SSC or cathodic hydrogen embrittlement. However, the older alloys (i.e., AISI 409, 430, 434, and 440) are much more susceptible to pitting and crevice corrosion than austenitic grades. New alloys have been developed with much better resistance to pitting and crevice corrosion, but these alloys are not always immune to chloride-SCC (Maurer 1976; Neumann and Griess 1964; Steigerwald et al. 1977).

The resistance of precipitation-hardened stainless steels to chloride-SCC in boiling magnesium chloride varies. PH 13-8 Mo was resistant for 15 days, while 17-4 PH and 15-5 PH failed in less than one day.

Effect of Chloride, Oxygen, and pH

It is well established that the severity of chloride-SCC increases with increasing chloride concentration. The threshold chloride concentration may be about 5 ppm (Neumann and Griess 1964).

Only trace amounts of oxygen (less than 100 ppb) are required for chloride-SCC of some austenitic steels (Neumann and Griess 1964). In order for the crack tip to propagate quickly enough to prevent repassivation, a rapid reduction reaction is required. Oxygen and oxidizing species such as ferric ion satisfy this requirement. Figure A.2-5 presents the effect of increasing chloride concentration at two dissolved oxygen concentrations. In more concentrated chloride solutions (greater than 1000 ppm sodium chloride), changes in oxygen concentrations have little effect on SCC resistance. In dilute chloride solutions (less than 100 ppm sodium chloride), small changes in oxygen concentration have a significant effect on susceptibility to SCC.

In the range normally found in geothermal environments, bulk pH is not a major factor. Cracking is more rapid, and cracks are more numerous in the pH 1.2 to 2.5 range (Baker et al. 1970).

Effect of Temperature

Severity of cracking increases with increasing temperature (Neumann and Griess 1964). For any given concentration of chloride, oxygen, and pH, a lower critical temperature exists below which chloride-SCC does not occur. This is illustrated for AISI 304 in Figure A.2-6.

Similar behavior has been observed for other austenitic stainless steels (Leckie 1970), but there are not enough data to construct figures similar to Figure A.2-6. From a design standpoint, the phenomenon of a

FIGURE A.2-5. EFFECT OF CHLORIDE AND OXYGEN ON TIME TO CRACKING TYPE 304 STAINLESS STEEL WIRE HELD AT CONSTANT LOAD IN SINGLE PHASE AQUEOUS ENVIRONMENT (Goldberg 1976)

NOTE: 15 mil diameter wire at 680°F and 20.0 ksi

FIGURE A.2-6. EFFECT OF pH, CHLORIDE CONTENT, AND TEMPERATURE OF THE STRESS CORROSION CRACKING OF TYPE 304 STAINLESS STEEL UNDER RESIDUAL WELD STRESSES. AS-WELDED TUBE SPECIMENS; SODIUM CHLORIDE DISSOLVED IN WATER UNDER AIR; EXPOSURE TIME UP TO 8000 HOURS (Goldberg 1976).

lower critical temperature means that the more resistant austenitic alloys (such as AISI 317 with 4.2 percent molybdenum or USS 18-18-2 with two percent silicon) should be tested in low temperature streams even if previous tests indicate they are not suitable for exposure to wellhead fluids.

Effect of Stress

Stress is required for chloride-SCC, but there is no evident lower critical stress. Time to fracture decreases sharply at stress at or above the yield point (Hines and Hoar 1956; Hoar and Hines 1956). Total stress is the critical factor. Applied stress actually presents relatively little difficulty because it can be quantified and allowed for. Residual stresses from cold work and welding are unpredictable. Post-welding stress may be near the yield point. Failures have occurred at zero applied stress (Leckie 1970). Austenitic stainless steels should be fully annealed.

Effect of Alloy Composition

Nickel has the major effect on susceptibility to chloride-SCC in chloride solutions. Immunity from chloride-SCC is not normally obtained unless the nickel content is less than 1 percent or greater than 45 percent (Watkins and Green 1976; Leckie 1970). All AISI austenitic stainless steels are susceptible to chloride-SCC under the severe test conditions of boiling magnesium chloride, but increasing nickel content above ten percent gives some increase in resistance.

Additions of molybdenum improve resistance to chloride-SCC. In boiling magnesium chloride, austenitic 18Cr-8Ni-3Mo was more resistant than molybdenum-free 18Cr-8Ni (Hines and Hoar 1956). AISI 317 LM steel with 4.2 percent molybdenum is superior to AISI 316 in resistance to chloride-SCC and local corrosion in aerated and deaerated chloride solutions (3000 and 30,000 ppm chloride) over a wide range of pH (Lizlovs 1977). This same alloy was immune to chloride-SCC for 1464 hours (test duration) in boiling, acidified, 25 percent sodium chloride (ph 1.5), while AISI 304 failed in 10 hours. The increased molybdenum content, and not the slightly higher chromium and nickel content, was responsible for the superiority (Lizlovs 1977; Dundas 1975).

Silicon addition also improved resistance to chloride-SCC. USS 18Cr-18Ni-2Si is 10 to 100 times more resistant than AISI 304 in boiling magnesium chloride and has a good process industry record in hot chloride systems (Loginow, Bates, and Mathay 1972). AISI 310 containing 1.5 percent silicon showed no chloride-SCC and no reaction to sulfides in nonacidic chloride solutions below 800°F. AISI 310 tends to tear and is difficult to machine.

AISI 314 contains more chromium and nickel than AISI 317 and has two to three percent molybdenum and 1.5 to 5 percent silicon. This alloy should be tested in geothermal streams.

Additions of small amounts of titanium, niobium, tungsten, or manganese may also improve resistance. Additions of constituents which favor precipitation of carbides and nitrides at the grain boundary decrease resistance to SCC.

Ferritic stainless steels containing more than one percent nickel are susceptible to chloride-SCC in magnesium chloride, although some resist cracking in the wick test and in boiling, twenty percent sodium chloride (Maurer 1976; Neumann and Griess 1964; Steigerwald et al. 1977). The addition of more than 0.5 percent copper is detrimental to ferritic steels (Goldberg 1976). The 26Cr-1Mo, 29Cr-4Mo, and 29Cr-4Mo-2Ni alloys depend on low interstitial concentrations of carbon or nitrogen to resist chloride-SCC in heat-affected zones. 26Cr-1Mo is also available in a titanium- or niobium-stabilized form. The 29Cr versions cannot be stabilized in this way because the amounts of titanium or niobium required adversely affect ductility and resistance to SCC (Steigerwald et al. 1977).

A.2.1.2.5 Comment on Laboratory Test Methods.

The oldest test for chloride-SCC is the boiling magnesium chloride test. This is an extremely severe environment, and it is often difficult to relate results from this test with results from less severe environments (Newmann and Griess 1964). The boiling lithium chloride test is usable at higher pH's, does not form an insoluble hydroxide, has better chemical purity, and cracks AISI 304 in an identical manner at similar times (Wilde 1971). The wick test (Dana and Delong 1956) is considered by many to be the most realistic test for marine and desalination environments. In the test, a dilute sodium chloride solution is "wicked up" onto an electrically heated U-bend where evaporation concentrates the sodium chloride. This test is thought to be especially representative where chloride solutions are flashed.

A.2.1.3 Intergranular Corrosion of Stainless Steels

Intergranular corrosion is severe, localized corrosion at or adjacent to grain boundaries, with little or no attack on the bodies of the grains. The alloy disintegrates (grains fall out) and/or loses its strength. Stress is not required.

A.2.1.3.1 Austenitic Stainless Steels

Intergranular corrosion occurs in austenitic stainless steels when they are sensitized (i.e., heated in the 950° to 1450°F range) and cooled slowly (Fontana and Greene 1967). The range may extend to 1650°F

(Cihal 1974). In this temperature range, chromium carbides form at the grain boundaries, and the metal adjacent to the carbides is depleted of chromium. Chromium levels may drop to less than two percent at the grain boundaries. Galvanic corrosion between the body of the grain and the grain boundary causes rapid corrosion of the boundary. When stainless steels are welded, a zone called the heat-affected zone (HAZ) along each side of the weld is heated into the sensitizing range. HAZ is a site of intergranular attack, often called weld decay.

Intergranular corrosion can be controlled in three ways. First, the material can be quench-annealed or solution-annealed (heated to high temperature, typically 1950° to 2050°F, and water quenched). At this annealing temperature, the chromium carbides are redissolved in the grain. The quenching is important because if the alloy is allowed to cool slowly, the entire structure will be sensitized. Stainless goods are usually supplied in the quench-annealed form. If they are welded during fabrication, they must be re-treated (Fontana and Greene 1967).

HAZ intergranular corrosion can be controlled by lowering the carbon content below 0.03 percent. These low carbon alloys do not require quench-annealing after welding and can be welded on-site. These alloys have a great propensity for picking up carbon when welded. The surfaces around the weld must be kept completely grease- and oil-free, or sensitization will occur.

HAZ intergranular attack can also be prevented by the addition of strong carbide formers or stabilizers to combine with the carbon. Niobium (or niobium plus tantalum) and titanium are used to stabilize stainless steels (Fontana and Greene 1967).

A.2.1.3.2 Ferritic Stainless Steels

Ferritic stainless steels are also subject to intergranular corrosion and weld decay. The same mechanism, chromium depletion, is responsible.

The range of sensitizing temperatures is not established, but sensitization of nickel-free ferritic steels begins at about 1700°F. Addition of two percent nickel raises the sensitization temperature to 1900°F. Molybdenum has little effect.

Quenching prevents intergranular corrosion. Weld decay of one to two percent nickel alloys can be prevented by one-hour treatment at 1510°F followed by water quenching. Lower nickel alloys require four hours at 1510°F (Bond and Lizlovs 1969).

Addition of more than 0.4 percent titanium to 18Cr-2Mo alloys completely prevents intergranular corrosion in the Strauss test after all

sensitizing treatments. Alloys containing more than 1.2 percent titanium are embrittled after annealing from 1510°F. This embrittlement can be removed by water quenching from 1900°F. Additions of 0.61 percent niobium prevent intergranular corrosion of post-weld specimens in the Strauss test (Bond and Lizlovs 1969).

A.2.1.4 Sulfide Stress Cracking (SSC) of Stainless Steels

Austenitic stainless steels are face-centered cubic and are generally considered to be immune to SSC. AISI 301, 304, and 310 at fully softened and at partially work-hardened conditions resisted SSC at 325°F (Troiano and Hehemann 1976).

Many martensitic stainless steels are very susceptible to SSC at ambient temperatures (Fraser and Treseder 1952). AISI 410 and Carpenter Custom 450 are susceptible at hardnesses well below HRC 22. A 13Cr martensitic steel at the Wairakei geothermal plant resisted SSC below HRC 10 but was susceptible at higher hardnesses. A special 12Cr alloy has been described that can be used in sulfide environments at HRC 27 or below (NACE 1975).

AISI 405 and 430 ferritic stainless steels in annealed condition with HRC less than or equal to 22 are suitable for hydrogen sulfide service at ambient temperatures (NACE 1975).

AM-350, AM-355, and 18Ni maraging steels offer no improvement over low alloy steels with regard to SSC resistance (Hudgins et al. 1966). 17-4 PH, 15-5 PH, and PH 13-8Mo are susceptible to SSC at stresses between 30 percent and 50 percent of yield (Watkins and Green 1976). A-286 was not susceptible at 98 percent of yield strength at room temperature. The resistance of A-286 decreases as temperature increases (Troiano and Hehemann 1976). Whether or not this effect is common to all precipitation hardening steels is not known.

A.2.2 Stainless Steels in Geothermal Steam

Steam from liquid-dominated geothermal fluids has corrosion characteristics of its own, but general corrosivity is dominated by two properties common to the saline fluid and condensate streams. First, carryover of entrained liquid provides the chloride needed for localized attack. Second, areas where local condensation may occur are subject to attack by low pH condensate containing hydrogen sulfide, carbon dioxide, and some chloride. (See Section A.1.2).

Tests run at Cerro Prieto using geothermal steam show how steam exposure affects the FEL for various stainless steels. Table A.2-1 indicates that increasing chromium or adding molybdenum and/or tungsten had little effect on the reduction in FEL relative to samples fatigued in air.

TABLE A.2-1. REDUCTION IN FATIGUE ENDURANCE LIMIT AT CERRO PRIETO AFTER 150 DAYS EXPOSURE

ALLOY	ROCKWELL B HARDNESS (Approximate)	REDUCTION IN FEL %
12 Cr	57	18.5
12 Cr-1Mo-1W	74	14.6
12 Cr-0.2Al	49	18.8
15 Cr-1.7Mo	41	11.7

Source: Mercado, A. 1976

AISI 616, AISI 403, and M152 stainless steels were tested at Baca for 160 days. Reductions in FEL of 36 to 52 percent were observed over 160 days. 12Cr martensitic steel was more resistant than the more alloyed steels (Toney, Cohen, and Cron 1977).

In the tests at Cerro Prieto and Baca, the samples were not under cyclic stress during exposure to the geothermal steam. Cyclic loading during exposure would have caused more severe damage.

The stainless steels are more resistant to corrosion-fatigue than the low alloy and carbon steels. Chromium is the most effective alloying element in the absence of hydrogen sulfide, while nickel is more effective against hydrogen sulfide (Wescott 1938). Best results are obtained with a combination of chromium and nickel (Gilbert 1956). Molybdenum is also beneficial (Westcott 1938).

A.2.3 Corrosion of Stainless Steels in Condensate Stream

Previous sections can be consulted for discussion of the effects of pH, hydrogen sulfide, carbon dioxide, ammonia, and oxygen in the condensate streams as well as the original saline fluid. Steam separation efficiency and aeration contribute to the corrosiveness of condensate streams (See section A.1.3).

Even with very efficient steam separation, the chloride content of the condensate can be high enough to cause problems. For example, assuming 25 percent flashing of a wellhead liquid containing 1 percent chloride and 0.05 percent liquid carryover, the condensate would contain about 20 ppm chloride. If the condensate is aerated and temperature is greater than 150°F to 176°F, chloride-SCC of some austenitic stainless steels could occur at this chloride concentration.

A.3 Nickel-Based Alloys

High nickel alloys are frequently used to combat severe corrosion problems. The higher ranked Ni-Cr-Mo alloys, such as Inconel 625 and Hastelloy C-276, have given excellent resistance to corrosion in geothermal systems.

A.3.1 General Guidelines for Using Nickel-Based Alloys in Liquid Geothermal Streams

The Ni-Cr-Mo alloys appear to be the most resistant to high temperature geothermal fluids. Inconel 625 and Hastelloy C-276 in particular can also normally tolerate very high flow rates and occasional aeration. Similar alloys containing iron in place of molybdenum face competition from the most resistant stainless steels, but may find application where their mechanical properties are desirable. Cupronickels and Monels will have limited usefulness in geothermal streams containing even trace quantities of hydrogen sulfide.

A.3.1.1 Uniform and Localized Corrosion of Ni-Cr-Mo Alloys

Effects of alloy composition are complex, but high molybdenum content is important for best corrosion resistance. Some pitting and crevice corrosion have been observed for Hastelloy G in both Salton Sea and Raft River fluids. Inconel 600 contains no molybdenum and was attacked at a rate of 10 mpy in a solution of one percent sodium chloride, ten ppm hydrogen sulfide, with pH 5, at 480°F (Shannon 1977). In the same tests, Hastelloy C-276 and Inconel 625 corroded at only 0.2 mpy.

A.3.1.2 Stress Corrosion Cracking (SSC) of Nickel-Based Alloys

Nickel-based alloys contain more than 45 percent nickel and should therefore have good resistance to chloride-SCC. If interstitial carbon is not kept low (less than 0.004 percent), these molybdenum-bearing, nickel-based alloys may be susceptible to SCC in heat-affected zones from welds (Streicher 1976).

The following alloys were resistant in the unsensitized state to boiling magnesium chloride for 15 days: Inconel 625, Inconel X750, Inconel 825, Monel K-500, Hastelloy C, Hastelloy C-276, and Hastelloy C-4

(Streicher 1976; Watkins and Green 1976). Other nickel-based alloys may also be resistant to SCC.

A.3.1.3 Sulfide Stress Cracking (SSC) and Hydrogen Embrittlement

Monel (HRB 63) and K-Monel (HRB 37) were completely resistant to sulfide stress cracking during the standard NACE test at ambient temperatures (Hudgins et al. 1966; Vollmer 1958). Monel K-500 (HRC 36), Inconel 625 (HRC 20 and HRC 39), Inconel X-570 (HRC 27), and Inconel 718 (HRC 34) were resistant at 98 percent yield stress. Hastelloy C-276 (HRC 41) and Hastelloy G (HRC 35) were also resistant (Watkins and Green 1976).

Hastelloys G and C-276 and Inconel 625 are susceptible to hydrogen embrittlement when coupled to steel. In the presence of dissolved oxygen, no hydrogen sulfide is required, but hydrogen sulfide reduced the time-to-failure (Kawashima, Agrawal, and Staehle 1977). The effect of coupling to steel has not been documented for other nickel-based alloys.

A.3.1.4 Intergranular Corrosion of Nickel-Based Alloys

The mechanism of intergranular corrosion of Hastelloy C, C-4, and C-276 is slightly different than that for austenitic stainless steels. At carbon concentrations greater than 0.004 percent, a molybdenum-rich carbide forms in the temperature range 1200° to 2200°F. This depletes molybdenum in the grain boundaries. The molybdenum-depleted zones are attacked by reducing acids (Streicher 1976) and could be affected by geothermal fluids.

A.3.2 Nickel-Based Alloys in Geothermal Steam

As described in previous sections, the corrosiveness of geothermal steam is dependent upon the degree of carryover of entrained liquid and the concentration of hydrogen sulfide, carbon dioxide, and chloride in areas of local condensation. (See Sections A.1.2 and A.3.1 for related information.)

A.3.3 Nickel-Based Alloys in Condensate Streams

The corrosiveness of condensate streams depends on the efficiency of steam separation, the quantity of non-condensable gases, the degree of aeration, and the pH of the condensate. These four factors are interactive. Further details and related information are available in Sections A.1.3 and A.3.1.

A.4 Titanium and Titanium Alloys

Titanium and its alloys have given good results in all but the most extreme environments when tested for geothermal applications.

A.4.1 General Guidelines for Use of Titanium and Titanium Alloys in Liquid Geothermal Streams

In general, pure titanium is somewhat less corrosion-resistant than some titanium alloys.

Iron particles left in scratches on titanium can initiate pits (Covington 1977). Care must be taken to avoid scratching the tubes with ferrous alloy tools. High-density, powder metallurgy titanium alloys are generally comparable to wrought equivalents. They offer cost advantages for complex shapes. Magnesium chloride inclusions in powder metallurgy titanium serve as nucleation sites for pitting. A low magnesium chloride alloy will give better service than one containing a few ppm magnesium chloride (Bohlmann and Posey 1967).

A.4.1.1 Uniform Corrosion of Titanium

The uniform corrosion rate of titanium and titanium alloys tested in geothermal fluids has been less than 0.3 mpy. The corrosion rates of these materials, when exposed to worst case conditions of aerated geothermal fluids, have been good. Corrosion rates have been less than 0.5 mpy.

Increasing temperature and chloride concentration do not increase uniform corrosion of titanium alloys. Experience in seawater desalination plants indicates that fluid velocities of 30 fps have no effect on uniform corrosion. Titanium is also very resistant to impingement and cavitation damage (George, Manning, and Schrieber 1975).

A.4.1.2 Pitting and Crevice Corrosion of Titanium

No significant local corrosion should occur in environments with less than ten percent chloride. Desalination experience and chemical process industry experience show that crevice corrosion in tight crevices may be a problem in high-temperature, high-chloride solution similar to Salton Sea fluid. Pitting may be an occasional problem.

The dominant factors controlling localized corrosion of titanium and its alloys are chloride concentration, pH, and temperature.

A.4.1.2.1 Effect of Chloride and Temperature

The interaction of chloride concentration and temperature in neutral solutions is shown in Figure A.4-1. This figure indicates that the ceiling temperature below which localized attack does not occur at any temperature in neutral solution is about 150°F. Below chloride concentrations of 10,000 ppm, resistance extends to above 500°F. This figure should be used with caution because in areas where flashing occurs, and in crevices or under deposits, the chloride concentration may be near saturation regardless of the chloride concentration of the bulk fluid.

FIGURE A.4-1. ANTICIPATED CORROSION PERFORMANCE OF UNALLOYED TITANIUM (ASTM GRADE 2) IN CHLORIDE BRINES AND UNDER SODIUM CHLORIDE SOLID SALT DEPOSITS (George, Manning, and Schrieber 1975)

Oxygen is required for good local corrosion resistance of titanium in hot, concentrated chloride solutions. Titanium crevices exposed to deaerated Salton Sea Fluid at 450°F underwent severe pitting and moderate crevice corrosion; samples in aerated (100 ppm oxygen) fluid were resistant to local corrosion (Needham et al. 1977).

A.4.1.2.2 Effect of pH

In the pH range normally found in geothermal fluids, decreasing pH lowers the usable ceiling temperature. Figure A.4-2 illustrates the effect of pH on crevice attack of pure titanium. Much better results are obtainable with small alloy additions.

A.4.1.2.3 Effect of Alloying on Pitting and Crevice Corrosion of Titanium

Some titanium alloys are much more resistant to local corrosion than commercially pure titanium. Ti-0.2Pd is the most resistant alloy (Sheppard et al. 1962; Takamura 1967) but may cost 70 percent more than titanium. TiCode-12 has almost equal resistance (Covington 1977) and may cost only about 20 percent more than titanium. Ti-1.5Ni, Ti-1.7W, and Ti-10V have given good results in Salton Sea tests. Ti-0.2Pd and TiCode-12 have usable temperature ceilings above 500°F in the pH range anticipated in geothermal streams.

Figure A.4-3 shows the effect of pH on crevice corrosion of TiCode-12. These results should be compared with those for pure titanium in Figure A.4-2 and Ti-0.2Pd in Figure A.4-4.

A.4.1.3 Galvanic Coupling of Titanium-Based Alloys

Titanium is cathodic to most other metals in saline environments. If the titanium area is large compared to the metal to which it is coupled, the second metal may corrode severely.

Since titanium is the cathode in most galvanic couples, hydrogen can be formed on titanium coupled to an active metal. Titanium is capable of absorbing hydrogen and becoming embrittled (Covington 1977). Some Ti-Ni alloys are susceptible to hydrogen embrittlement in desalination service (George, Manning, and Schrieber 1975).

Titanium-tube-to-Monel-tubesheet crevices strongly resist crevice corrosion, but this couple has caused pitting of titanium under salt scale at sites some distance from the crevice. Titanium-to-AISI 316 crevices are also resistant to crevice attack. Tight titanium-to-Teflon crevices are much more susceptible to attack than titanium-to-titanium crevices.

FIGURE A.4-2. EFFECT OF TEMPERATURE AND pH ON CREVICE CORROSION OF UNALLOYED TITANIUM (GR.2) IN SATURATED SODIUM CHLORIDE BRINE (Franson 1977)

FIGURE A.4-3. EFFECT OF TEMPERATURE AND pH ON CREVICE CORROSION OF TiCODE -12 (GR.12) IN SATURATED SODIUM CHLORIDE BRINE (Franson 1977)

FIGURE A.4-4. EFFECT OF TEMPERATURE AND pH ON CREVICE CORROSION OF Ti-0.2 Pd IN SATURATED SODIUM CHLORIDE BRINE (Franson 1977)

A.4.1.4 Stress Corrosion Cracking (SSC) of Titanium-Based Alloys

Commercial titanium alloys are not considered to be susceptible to cracking in three percent sodium chloride solutions at ambient temperatures. However, precracked specimens of many of these alloys fail rapidly in three percent sodium chloride solutions. This behavior indicates that the SCC resistance of some titanium alloys is dependent on the integrity of the protective oxide film and not on the intrinsic resistance of the alloy lattice (Boyd 1967). SCC should therefore not be a major problem, provided that components are not precracked during fabrication and that the design does not allow excessive vibration of titanium parts.

The susceptibility of precracked titanium alloys to SCC is adversely affected by aluminum, tin, manganese, cobalt, and/or oxygen content. Some alloys containing more than 6 percent aluminum are especially susceptible. Additions of molybdenum, niobium, or vanadium reduce or eliminate the susceptibility to chloride-enhanced propagation of cracks in precracked specimens (Boyd 1967). Table A.4-1 lists resistant alloys and also alloys which are sensitive in the precracked condition.

Only chloride, bromide, or iodide ions are effective as cracking agents. Fluoride, hydroxide, sulfide, sulfate, nitrate, perchlorate, cyanide, and thiocyanate have no effect. Different alkali or alkaline-earth cations have little effect on cracking (Beck 1967).

Both hydrogen embrittlement and active path dissolution are involved in the mechanism of crack propagation (Boyd 1967; Covington 1977; Mauney, Starke, and Hochman 1973).

A.4.2 Titanium and Titanium Alloys in Geothermal Steam

As described in previous sections, the corrosiveness of geothermal steam is dependent upon the degree of carryover of entrained liquid and the concentration of hydrogen sulfide, carbon dioxide, and chloride in areas of local condensation (see Sections A.1.2 and A.4.1 for related information).

A.4.3 Titanium and Titanium Alloys in Condensate Streams

Titanium was used successfully for hydrogen and oil coolers exposed to aerated cooling water/condensate at the Cerro Prieto geothermal facility (Mercado, S. 1979). Two other heat exchanger materials had failed in this environment.

The corrosiveness of condensate streams in general depends on the efficiency of steam separation, the quantity of noncondensable gases, the degree of aeration, and the pH of the condensate. These four factors are interactive. Further details and related information are available in Sections A.1.3 and A.4.1.

TABLE A.4-1. SENSITIVITY OF TITANIUM ALLOYS TO CRACK PROPAGATION
BY CHLORIDE IONS

TITANIUM ALLOYS WHICH UNDERGO ACCELERATED CRACK PROPAGATION IN AMBIENT 3 WT PERCENT SODIUM CHLORIDE	TITANIUM ALLOYS WHICH DO NOT UNDERGO ACCELERATED CRACK PROPAGATION IN AMBIENT 3 WT PERCENT SODIUM CHLORIDE
Unalloyed Ti (with high oxygen content, i.e., 0.317 percent)	
Ti-8Mn	Ti-2Al-4Mo-4Zr
Ti-2.25Al-1Mo-11Sn-5Zr-0.2Si (IMI-679)	Ti-4Al-3Mo-1V
Ti-3Al-11Cr-13V	Ti-5Al-2Sn-2Mo-2V
Ti-4Al-4Mn	Ti-6Al-2Mo
Ti-5Al-2.5Sn	Ti-6Al-2Sn-1Mo-1V
Ti-6Al-2.5Sn	Ti-6Al-2Sn-1Mo-3V
Ti-6Al-4V	Ti-6Al-2Cb-1Ta-0.8Mo
Ti-6Al-3Cb-2Sn	Ti-6.5Al-5Zr-1V
Ti-6Al-4V-1Sn	Ti-6Al-2.5Mo (as received and beta annealed + WQ + 1100°F, aged for 2 hr)
Ti-6Al-4V-2Co	
Ti-6Al-6V-2.5Sn	
Ti-7Al-2Cb-1Ta	
Ti-6Al-3Cb (as received and beta annealed)	
Ti-6Al-3Mo	
Ti-7Al-3Cb-2Sn	
Ti-8Al-1Mo-1V	
Ti-8Al-3Cb-2Sn	

Source: Boyd 1967

A.5 Copper-Based Alloys

In lower temperature (120° to 200°F) geothermal resources in the United States, copper fan-coil units and copper-tubed heat exchangers have given consistently poor service. This is due to traces of sulfide species in the geothermal fluids. Uniform corrosion rates of copper tubing in heat transfer service are typically 2 to 6 mpy. These corrosion rates are more than tenfold greater than rates measured with coupons in the same fluid. Copper tubing rapidly becomes fouled by a thick, porous cuprous sulfide film, and crevice corrosion occurs at cracks in this film.

Experience in Iceland indicates that brasses and bronzes are even less suitable for heat transfer applications. Cupronickels are susceptible to serious attack by sulfides in concentrations as low as seven parts per billion in deaerated seawater, and their suitability in lower temperature resources is questionable.

The suitability of most copper-based alloys for higher temperature applications is also doubtful. At Raft River where hydrogen sulfide is less than 0.1 ppm, the performance of copper-nickel alloys (Monel 400, 70-30 cupronickel, 90-10 cupronickel) was poor. Some nickel-free brasses and bronzes, especially aluminum bronzes, are suitable for thick-walled applications such as valve bodies (Miller 1977).

The cracking of some copper-based alloys, especially α -brasses, exposed to ammonia or ammonia derivatives is well known under the name "season cracking" (Fontana and Greene 1967). When cracking is caused by ammonia species, cupric ammonium complexes are required at the metal surface in significant quantity. An adsorbed layer of oxygen or a thin oxide film also seems necessary (Booker 1967; Pugh, Craig, and Sedriks 1967). Unless the ammonia or ammonium level is high, cracking by ammonia species in the liquid phase of geothermal fluid should be limited to stagnant areas. Ammonia in the steam phase could concentrate in moisture films, posing a considerable hazard.

pH has a considerable effect on SCC of copper-based alloys by ammonia species. Cracking does not appear to occur at pH less than 3.9. Between 3.9 and 4.7, a red coating is formed, and cracking is transgranular. From pH 4.7 to 7.5, thin tarnish films form, and the cracking is intergranular. At pH greater than 7.5, no film forms, and cracking is again transgranular.

The susceptibility of copper-zinc brasses to cracking by ammonia species increases with increasing zinc concentration. In Cu-Ni brasses the susceptibility is maximum at about 10 percent Ni. Resistance increases sharply above approximately 30 percent Ni. The resistance of Cu-Al alloys is lowest between 1 and 2 percent Al and increases sharply above approximately 5 percent Al (Pugh, Craig, and Sedriks 1967).

SCC of Admiralty brass under anodic polarization but in the absence of ammonia has been observed (Kawashima, Agrawal, and Staehle 1977).

A.6 Applicability of Other Metallic Materials

A number of other metals and alloys may either have important specialized but limited uses in geothermal applications or have not shown promise in geothermal tests. These materials are discussed in this section.

A.6.1 Cobalt Alloys

Cobalt alloys may find application in services requiring high strength combined with resistance to sulfide stress cracking (SSC) and in service requiring wear resistance.

MP35N resists SSC at high yield strengths and may be useful for well instrumentation cables, pump springs, and other downhole tools. Haynes 25 was resistant to very high velocity, acidified, Salton Sea fluid during a short-term test (Austin et al. 1977). No pitting or crevice corrosion of Haynes 6B, another wear-resistant alloy, was observed in Raft River field tests.

Cobalt-based alloys generally have good resistance to sulfide stress cracking. MP35N (HRC 51), MP159 (HRC 46), and Haynes Alloy 25 (HRC 47) were resistant at 89 percent yield strength (YS) (Watkins and Green 1976). Stellites 1 and 6 were also resistant (Fraser and Treseder 1952). However, MP35N may be susceptible to sulfide stress cracking when coupled to a more active metal such as iron (Troiano and Hehemann 1976). The effect of galvanic coupling on the SSC resistance of other cobalt alloys is not known.

Alloys MP35N and MP159 are resistant to SCC in boiling magnesium chloride (Watkins and Green 1976). Data about other cobalt alloys are lacking.

A.6.2 Zirconium and Tantalum

Zirconium and tantalum may be considered for severe, hot acid chloride service, such as injection nozzles for acidifying fluid with hydrochloric acid.

A.6.3 Aluminum Alloys

Aluminum alloys have not shown good resistance in tests conducted in direct contact with geothermal fluids. Rapid pitting of aluminum heat exchanger tubes and test coupons was observed in condensate and cooling

water at Cerro Prieto, Mexico (Mercado, A. 1976). Low levels of transition metal ions, especially copper and mercury, greatly increase localized attack of aluminum alloys. These ions are present in most liquid-dominated geothermal fluids.

Aluminum alloys are subject to severe attack when galvanically coupled to almost any other metal likely to be used in a geothermal plant.

Exterior siding and structural components of aluminum are likely to give adequate service due to the good atmospheric corrosion behavior of aluminum and resistance to occasional sulfide emissions. Fluoropolymer-coated aluminum exterior siding panels are used in new housings at The Geysers power plant.

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APPENDIX B

CORROSION IN SEAWATER DESALINATION PLANTS

B.0 CORROSION IN SEAWATER DESALINATION PLANTS

Geothermal fluids are similar in many ways to seawater. Therefore, corrosion experience from desalination plants may be useful when actual geothermal corrosion data are not available. There are two major restrictions on the applicability of desalination experience to geothermal corrosion problems.

First, the maximum temperature used in most desalination plants is around 250°F. This is considerably lower than geothermal inlet conditions.

Secondly, the chemical compositions of seawater and geothermal fluid may differ in several ways. Seawater for desalination near 250°F is normally pretreated to remove carbon dioxide and then adjusted to about pH 7. Many geothermal fluids may also contain ammonia and hydrogen sulfide which are not found in seawater. The presence of hydrogen sulfide causes severe corrosion of some alloys which can give good service in its absence. Some geothermal fluids also contain larger concentrations of heavy metal ions, especially copper and mercury ions. A typical analysis for the major constituents which account for the chemical behavior of seawater is given in Table B.0-1.

TABLE B.0-1. NORMAL SEAWATER

COMPONENT	CONCENTRATION (ppm)
Sodium (Na^+)	10768
Magnesium (Mg^+)	1298
Calcium (Ca^+)	408
Potassium (K^+)	388
Chloride (Cl^-)	19361
Sulfate (SO_4^{-2})	2702
Bicarbonate (HCO_3^-)	143
Total Solids	35175

Source: George, Manning, & Schreiber 1975

B.1 Corrosion Results

B.1.1 Aluminum

Geothermal experience indicates that the usefulness of aluminum in contact with geothermal fluids is limited. Though it did well in corrosion tests at Cerro Prieto, aluminum failed rapidly in service as oil and hydrogen cooling heat exchangers exposed to aerated cooling waters. Aluminum also performs poorly in desalination environments. The tendency to pit is increased by heavy metal ions. Also, galvanic coupling is a problem; aluminum is anodic to most other metals and must be insulated from all contact (George, Manning, and Schrieber 1975).

B.1.2 Copper-Based Alloys

Uniform corrosion data for twelve copper alloys tested at the OSW Materials Test Center are presented in Table B.1-1. These results are for seawater controlled at pH 7.4; corrosion increases rapidly at pH less than 7.0. Other types of corrosion were also noted for copper alloys. Table B.1-2 shows the results of impingement corrosion. Destruction of the cupric film will cause all copper alloys to pit under deposits or where the seawater velocity is greater than 8 fps. Hydrogen sulfide and ammonia (or ammonium) greatly increase the pitting of copper alloys. Alloys 443 and 687 undergo stress corrosion cracking (SCC) and become major hazards if exposed to ammonia, ammonium, or mercury. Alloy 706 is a minor stress corrosion cracking hazard under these conditions. Brasses with more than fifteen percent zinc must be inhibited with arsenic or antimony to prevent dealloying (George, Manning, and Schrieber 1975).

TABLE B.1-2. IMPINGEMENT CORROSION OF COPPER ALLOYS AT THE OSW TEST CENTER

COPPER ALLOY		IMPINGEMENT CORROSION (mpy)	
Designation	Alloy No.	10 fps	15 fps
Arsenical Admiralty Brass	443	84	112
Arsenical Aluminum Brass	687	40	60
90/10 Cu/Ni	706	28	48
70/30 Cu/Ni (.4 - .7 Fe)	715	12	44

B.1.3 Low Alloy Steels

The corrosion behavior of some low alloy steels and pure iron in seawater at 250°F is presented in Table B.1-3. Pitting and crevice corrosion of the low alloy steels were severe, but traces of oxygen (less than 50 ppb) were present in the flowing seawater. This would facilitate pitting and crevice corrosion.

TABLE B.1-1. CORROSION OF COPPER-BASED ALLOYS AT THE OSW MATERIALS TEST CENTER AT FREEPORT, TEXAS

METAL			GENERAL CORROSION (mpy)																		
			Heat Recovery Exchanger ¹										Vertical Tube Evaporator ² 219°F O ₂ = 0 ppb	Concentrated Brine Recycle ³ 219°F O ₂ = 0 ppb 35,000 ppm TDS	Brine Heater Section ³ 250°F O ₂ = 0 ppb 29,000 ppm TDS	Oxygenation Study ⁴ Concentrated Brine (35,000 ppm TDS)					
			113°F		149°F		174°F		195°F		210°F					171°F			219°F		
Alloy No.	Method of Manufac- ture	Temper	O ₂ = 75 ppb No Fe Added	O ₂ = 0.1 ppm Fe Added ⁵	O ₂ = 65 ppb No Fe Added	O ₂ = 0.1 ppm Fe Added ⁵	O ₂ = 60 ppb No Fe Added	O ₂ = 0.1 ppm Fe Added ⁵	O ₂ = 47 ppb No Fe Added	O ₂ = 0.1 ppm Fe Added ⁵	O ₂ = 35 ppb No Fe Added	O ₂ = 0.1 ppm Fe Added ⁵				O ₂ = 20 ppb	O ₂ = 100 ppb	O ₂ = 200 ppb	O ₂ = 20 ppb	O ₂ = 100 ppb	O ₂ = 200 ppb
122	S	LD	—	—	—	—	—	—	—	—	—	—	1.26	0.62	4.2	—	—	—	—	—	—
142	S	LD	—	—	—	—	—	—	—	—	—	—	1.35	0.46	3.6	—	—	—	—	—	—
192	S	A	—	—	—	—	—	—	—	—	—	—	—	0.49	—	—	—	—	—	—	—
194	SW	EH	2.9-3.2	1.0-2.0	3.8-3.9	2.1-2.1	1.7-3.4	1.7-2.0	1.2-3.0	2.7-3.9	4.0-4.8	4.2-4.3	1.42	0.50	4.0	0.2	0.6	1.5	1.1	5.1	3.0
433	S	A	—	—	—	—	—	—	—	—	—	—	—	0.49	4.0	—	—	—	—	—	—
608	S	A	—	—	—	—	—	—	—	—	—	—	0.12	0.33	1.3	—	—	—	—	—	—
613	S	A	1.4-7.9	0.7-0.7	1.4-11.8	0.9-1.3	1.2-1.5	0.5-0.6	1.2-1.7	0.5-0.7	1.5-2.9	0.7-0.8	0.50	0.26	1.4	—	—	—	—	—	—
687	S	A	—	—	—	—	—	—	—	—	—	—	0.42	0.54	1.3	0.15	0.8	0.2	1.4	6.4	9.9
687	SW	A	1.9-4.0	0.5-0.7	1.7-5.9	1.7-1.8	2.4-3.5	0.9-1.9	1.2-4.7	1.6-1.7	3.4-6.0	1.8-1.9	—	—	—	—	—	—	—	—	—
706	S	LD	—	—	—	—	—	—	—	—	—	—	0.40	0.42	1.4	—	—	—	—	—	—
706	S	HD	—	—	—	—	—	—	—	—	—	—	0.55	0.30	1.8	—	—	—	—	—	—
706	SW	EH	—	—	—	—	—	—	—	—	—	—	0.60	0.31	—	0.15	0.5	0.4	0.3	0.9	0.8
706	SWSW	EH	2.4-3.3	0.4-0.7	3.5-3.6	1.5-1.7	1.9-2.3	0.8-1.3	3.1-3.3	2.0-2.1	4.2-4.3	2.3-2.4	—	—	—	—	—	—	—	—	—
715	SW	A	—	—	—	—	—	—	—	—	—	—	—	0.18	2.0	—	—	—	—	—	—
715	S	A	—	—	—	—	—	—	—	—	—	—	0.44	0.18	1.6	0.2	0.3	0.1	0.2	0.4	0.1
715	SW	A	1.7-3.3	0.7-1.2	2.6-3.8	1.1-1.1	1.7-2.9	0.7-0.9	2.9-3.3	1.3-1.6	2.4-3.3	1.6-2.0	—	—	—	—	—	—	—	—	—
715 mod	S	A	—	—	—	—	—	—	—	—	—	—	—	—	0.8	—	—	—	—	—	—
716	S	A	—	—	—	—	—	—	—	—	—	—	—	—	1.4	—	—	—	—	—	—
720	S	A	—	—	—	—	—	—	—	—	—	—	—	—	1.1	—	—	—	—	—	—

Feed was controlled at pH = 7.4 and O₂ = 75 ppb

S = seamless

SW = seam welded

SW = butt welded

A = annealed

RH = half hard

LD = light drawn

HD = hard drawn

¹Values are results of two trials of 5 months each.

²Tubes pulled after 29 months exposure.

³Tubes pulled after 54 months.

⁴90 days exposure.

⁵Added as FeSO₄. 0.1 ppm ferrous ions have been shown to reduce general corrosion by 50 percent. A sacrificial length of iron pipe in the intake system could provide sufficient ferrous ions.

Source: George, Manning and Schriber 1975

TABLE B.1-3. CORROSION OF LOW ALLOY STEELS IN FLOWING SYNTHETIC SEAWATER

MATERIAL	EXPOSURE (days)	VELOCITY (fps)	UNIFORM CORROSION (mpy)	PITTING ATTACK ^a	CREVICE ATTACK
Ultra High purity iron	10	0.3	5.3	slight	
A-104 (pure iron)	10	3-4	11.1		
	20	3-4	8.9	severe	
	30	3-4	11.1	severe	
A-104 (electron beam melted as rolled)	10	0.3	8.6	very slight	very slight
	20	0.3	5.8		slight
	30	0.3	4.9		slight
A-104 (induction melted as rolled)	10.8	0.3	6.5	slight	
	21.1	0.3	3.7	moderate	moderate
A-104 (induction melted, annealed)	31.1	0.3	3.1		severe
Armco iron (as rolled)	8.7	0.3	4.3		slight
	9.7	0.3	7.3	very slight	
	19.5	0.3	3.2	slight	slight
	29.1	0.3	2.4	slight	
	42.3	0.3	1.9	moderate	
	82.3	0.3	2.0	moderate	moderate
Armco iron (annealed)	9.7	0.3	5.5	very slight	
	19.5	0.3	3.3		slight
	29.1	0.3	2.2	slight	
	51.0	0.3	2.1	moderate	
ASTM A-212 (rolled and ground)	10	0.6	4.4	moderate	
	20	0.6	3.7	moderate	
	30	0.6	2.6	slight	slight
	10	3-4	7.0	slight	
	20	3-4	3.7	severe	severe
	30	3-4	3.2	moderate	severe
ASTM A-285 (rolled and ground)	10	0.6	4.9	moderate	moderate
	20	0.6	3.8	moderate	moderate
	30	0.6	3.1	slight	slight
	10	3-4	6.1	small blisters	
	20	3-4	3.8	severe	severe
	30	3-4	3.0	severe	severe

^aQualitative data only. No definition of descriptors.

Test conditions: flowing synthetic sea water, 121°C, pH 6.4-7.9, <50 ppb O₂.

Source: Banning and Oden 1973

B.1.4 Stainless Steels

Austenitic stainless steels have good general corrosion resistance to nonaerated seawater. Many have good pitting and crevice corrosion resistance in nonaerated media. When seawater is aerated, pitting, crevice corrosion, and SCC become major concerns. Table B.1-4 presents the results of pitting tests on nineteen stainless steel alloys tested at the OSW Materials Test Facility at Freeport, Texas. These results apply to stainless steels in seawater with varying dissolved oxygen concentrations.

TABLE B.1-4. PITTING CORROSION OF STAINLESS STEEL ALLOYS IN THE AISI DESALINATION PLANT AT FREEPORT, TX

PITTING CORROSION OF HEAT EXCHANGER TUBES (walls .49 mil thick)								
MATERIAL TESTED	Heat Recovery Unit 110-200°F		Brine Heater 235-250°F		Brine Recycle Loop 221°F		Vertical Tube Evaporator	
	Length of Exposure	Growth of Deepest Pit	Length of Exposure	Growth of Deepest Pit	Length of Exposure	Growth of Deepest Pit	Length of Exposure	Growth of Deepest Pit
AISI Standard Grades								
Type 202	12 mo	25 mpy	12 mo	5 mpy	30 mo	2.2 mpy	--	--
Type 304	24 mo	perforated ^a	12 mo	5 mpy	12 mo	4 mpy	18 mo	17 mpy
Type 309	24 mo	1.5 mpy	24 mo	10 mpy	24 mo	2 mpy	--	--
Type 316	24 mo	no pits	18 mo	13 mpy	36 mo	1.1 mpy	18 mo	3 mpy
Type 317	30 mo	no pits	24 mo	no pits	24 mo	no pits	12 mo	2.5 mpy
Type 430	6 mo	perforated ^b	6 mo	40 mpy	12 mo	30 mpy	6 mo	40 mpy
Other Grades								
Allegheny 216	36 mo	no pits	36 mo	4 mpy	36 mo	no pits	30 mo	1 mpy
Allegheny 304N	18 mo	perforated ^c	18 mo	7 mpy	18 mo	4 mpy	--	--
Allegheny 329	36 mo	no pits	36 mo	0.5 mpy	36 mo	no pits	30 mo	1 mpy
Allegheny 329X	6 mo	no pits	6 mo	no pits	6 mo	no pits	--	--
Allegheny 409	6 mo	perforated ^b	6 mo	80 mpy	12 mo	30 mpy	12 mo	12 mpy
Allegheny 444L	12 mo	perforated ^c	12 mo	4 mpy	12 mo	20 mpy	12 mo	20 mpy
Incoloy 800	30 mo	no pits	24 mo	2.5 mpy	24 mo	no pits	--	--
E-Brite 26-1	24 mo	no pits	24 mo	7 mpy	24 mo	no pits	18 mo	2 mpy
18/2/.25 Cr/Mo/Ti	6 mo	50 mpy	6 mo	10 mpy	6 mo	2 mpy	--	--
18/18/2 Cr/Ni/Mn	6 mo	50 mpy	6 mo	30 mpy	12 mo	no pits	6 mo	70 mpy
Armco 22-13-5	24 mo	4 mpy	24 mo	<0.5 mpy	24 mo	no pits	6 mo	6 mpy
Armco 20-45-5	18 mo	no pits	18 mo	17 mpy	18 mo	no pits	18 mo	3 mpy
Carpenter 20-Cb3	36 mo	no pits	36 mo	<0.3 mpy	36 mo	no pits	30 mo	1 mpy
Allegheny 6X	24 mo	no pits	24 mo	1.5 mpy	24 mo	no pits	18 mo	2 mpy

^a Perforation occurred after 12 months, but before 18 months exposure.

^b Perforation occurred after less than 6 months exposure.

^c Perforation occurred after 6 months, but before 12 months exposure.

Note: The seawater feed to the heat recovery unit was controlled with pH = 7.0, oxygen = 25 ppb and carbon dioxide = 1 ppb. Most of the dissolved oxygen was probably consumed in the Heat Recovery Unit.

Source: George, Manning, and Schrieber 1975.

REFERENCES

Banning, L.H., and Oden, L.L. 1973. Corrosion resistance of metals in hot brines: A literature review. IC 8601. Albany, OR: Albany Metallurgy Center.

George, P.F., Manning, J.E., Jr., and Schrieber, C.F. May 1975. Desalination Materials Manual. Dow Chemical Co.

APPENDIX C

WORLDWIDE GEOTHERMAL POWER PRODUCTION

C.0 WORLDWIDE GEOTHERMAL POWER PRODUCTION

The worldwide use of geothermal energy for electric power generation is summarized in this appendix. Included are:

1. the capacities of plants presently on-line,
2. plants scheduled to go on-line by 1982, and
3. plants planned for after 1982.

Dismantled pilot plants are not included. The country, plant name, year of start-up, and generating capacity of the plants are taken from Geothermal Energy as a Source of Electricity (DiPippo 1980). The power cycle designations are those used in Section 3.1 of this document. A key to the designations is also in a footnote below Table C.0-1.

TABLE C.O-1. WORLDWIDE GEOTHERMAL POWER PLANTS

Country/Power Plant	Year of Start-up	Capacity-MW	Power Cycle ^a
<u>AZORES</u>			
Sao Miguel	1979	3.0	LD
<u>CHILE</u>			
El Tatio	Future	15.0	LD
<u>CHINA</u>			
Yang-Pa-Ching	1978	1.0	LDN-SF
<u>COSTA RICA</u>			
Miravalles	Future	40.0	LD
<u>EL SALVADOR</u>			
Ahuachapan, Auxiliary Unit	1975	1.1	LDN-SF
Ahuachapan, Unit 1	1975	30.0	LDN-SF
Ahuachapan, Unit 2	1976	30.0	LDN-SF
Ahuachapan, Unit 3	1980	35.0	LDN-SF
Berlin	Future	100.0	LD
Chinameca	Future	100.0	
Chipilapa	Future	50.0	
San Vicente	Future	100.0	
Installed (July 1979) 60.0 MW			
Planned (1979-1982) 35.0 MW			
Future (After 1982) 350.0 MW			
<u>GUATEMALA</u>			
Amatitlan	Future	50.0	
<u>HONDURAS</u>			
Pavana or San Ignacio	Future	50.0	
<u>ICELAND</u>			
Namafjall (Dismantled)	1969	3.0	LDN-SF
Krafla, Unit 1	1978	30.0	LDN-SF
Krafla, Unit 2	Future	30.0	LDN-SF
Svartsengi (Grindavik)	1978	2.0	LDN-SF
Installed (July 1979) 32.0 MW			
Planned (1979 - 1982) 0.0 MW			
Future (After 1982) 30.0 MW			
<u>INDONESIA</u>			
Kawah Kamojang	1979	0.25	SDR
Kawah Kamojang	Future	100.00	SDR

Continued

TABLE C.0-1. WORLDWIDE GEOTHERMAL POWER PLANTS (Continued)

Country/Power Plant	Year of Start-up	Capacity-MW	Power Cycle ^a
ITALY			
Larderello 2 (5 Units)	---	69.0	SDR
Larderello 3 (6 Units)	1969	120.0	SDR
Gabbro	1969	15.0	SDR
Castelnuovo V.C. (4 Units)	---	50.0	SDR
Serrazzano (5 Units)	---	47.0	SDR
Lago 2 (3 Units)	---	33.5	SDR
Sasso Pisano (2 Units)	---	15.7	SDR
Monterotondo	---	12.5	SDR
Sant'Ippolito-Vallonsordo	1972	0.9	SDR
Lagoni Rossi 1	1962	3.5	SDR
Lagoni Rossi 2	---	3.0	SDR
Sasso 1	---	7.0	SDR
Capriola	---	3.0	SDR
Molinetto	---	3.5	SDR
Travale	1973	15.0	SDR
Bagnore 1	1959	3.5	SDR
Bagnore 2	---	3.5	SDR
Piancastagnaio	1969	15.0	SDR
(Unspecified Sites)	Future	400.0	
			Installed (July 1979) 420.6 MW
			Planned (1979-1982) 0.0 MW
			Future (After 1982) 400.0 MW
JAPAN			
Matsukawa	1966	20.0	SDR
Otake	1967	10.0	LDN-SF
Onuma	1973	10.0	LDN-SF
Onikobe	1975	25.0	SDR
Hatchobaru	1977	50.0	LDN-SF
Kakkonda (Takinove)	1978	50.0	SDR
Otake (Pilot Binary; Dismantled)	1978	1.0	LDN-B
Mori (Pilot Binary; Dismantled)	1978	1.0	LDN-B
Mori	1979	55.0	LDN-SF
Kusuneda	Future	50.0	
			Installed (July 1979) 165.0 MW
			Planned (1979-1982) 55.0 MW
			Future (After 1982) 50.0 MW
KENYA			
Olkaria	Future	15.0	LD
MEXICO			
Cerro Prieto I, Unit 1	1973	37.5	LDN-SF
Cerro Prieto I, Unit 2	1973	37.5	LDN-SF
Cerro Prieto I, Unit 3	1979	37.5	LDN-SF
Cerro Prieto I, Unit 4	1979	37.5	LDN-SF
Cerro Prieto I, Unit 5	1982	30.0	LDN-SF
Cerro Prieto II	Future	110.0	
			Installed (July 1979) 150.0 MW
			Planned (1979-1982) 30.0 MW
			Future (After 1982) 110.0 MW

Continued

TABLE C.0-1. WORLDWIDE GEOTHERMAL POWER PLANTS (Continued)

Country/Power Plant	Year of Start-up	Capacity-MW	Power Cycle ^a
NEW ZEALAND			
Kawerau	1961	10.0	LDN-SF
Wairakei, Station A:			
Machine 1 (IP)**	1959	11.2	LDN-SF
Machine 2 (HP)*	1958	6.5	LDN-SF
Machine 3 (HP)	1959	6.5	LDN-SF
Machine 4 (IP)	1959	11.2	LDN-SF
Machine 5 (HP)	1962	11.2	LDN-SF
Machine 6 (HP)	1962	11.2	LDN-SF
Machine 7 (LP)***	1959	11.2	LDN-SF
Machine 8 (LP)	1959	11.2	LDN-SF
Machine 9 (LP)	1960	11.2	LDN-SF
Machine 10 (LP)	1960	11.2	LDN-SF
Wairakei, Station B:			
Machine 11 (MP)****	1962	30.0	LDN-DF
Machine 12 (MP)	1963	30.0	LDN-DF
Machine 13 (MP)	1963	30.0	LDN-DF
Ohaki (Broadlands)	Future	150.0	LDN-DF
Installed (July 1979) 202.6 MW Planned (1979-1982) 0.0 MW Future (After 1982) 150.0 MW			
NICARAGUA			
Momotombo	Future	30.0	LD _____
PANAMA			
Oerro Pando	Future	_____	_____
PHILIPPINES			
Tongonan (Leyte) Portable Unit	1977	3.0	LDN-SF
Tongonan (Leyte) Unit 1	1980	55.0	_____
Tongonan (Leyte) Unit 2	1981	55.0	_____
Makiling Banahaw (Los Banos) Wellhead Unit	1977	1.2	LDN-SF
Makiling Banahaw (Los Banos) Unit 1	1979	55.0	LDN-DF
Makiling Banahaw (Los Banos) Unit 2	1979	55.0	LDN-DF
Makiling Banahaw (Los Banos) Unit 3	1981	55.0	LDN-DF
Makiling Banahaw (Los Banos) Unit 4	1982	55.0	LDN-DF
Tiwi Unit 1	1979	55.0	LDN-DF
Tiwi Unit 2	1979	55.0	LDN-DF
Tiwi Unit 3	1981	55.0	LDN-DF
Tiwi Unit 4	1981	55.0	LDN-DF
Southern Negros Unit 1	1981	55.0	_____
Southern Negros Unit 2	1982	55.0	_____
Manat-Masara Unit 1	1981	55.0	_____
Manat-Masara Unit 2	1982	55.0	_____
Installed (July 1979) 59.2 MW Planned (1979-1982) 715.0 MW Future (After 1982) 550.0 MW			
*HP - High pressure steam **IP - Intermediate pressure steam ***LP - Low pressure steam ****MP - Mixed pressure			

Continued

TABLE C.0-1. WORLDWIDE GEOTHERMAL POWER PLANTS (Continued)

Country/Power Plant	Year of Start-up	Capacity-MW	Power Cycle ^a
<u>TURKEY</u>			
Kizildere, Wellhead Unit	1975	0.5	LDN-SF
Kizildere, Unit 1	Future	14.0	
<u>UNION OF SOVIET SOCIALIST REPUBLICS</u>			
Parantun (Dismantled)	1967	0.7	LDN-B
Pauzhetka	1967	5.0	LDN-SF
Bolshoye Bannoye	Future	8.0	LDN-DF
Installed (July 1979) 5.0 MW Planned (1979-1982) 0.0 MW Future (After 1982) 78.0 MW			
<u>UNITED STATES</u>			
The Geysers, Unit 1, PG&E	1960	11.0	SDR
The Geysers, Unit 2, PG&E	1963	13.0	SDR
The Geysers, Unit 3, PG&E	1967	27.0	SDR
The Geysers, Unit 4, PG&E	1968	27.0	SDR
The Geysers, Unit 5, PG&E	1971	53.0	SDR
The Geysers, Unit 6, PG&E	1971	53.0	SDR
The Geysers, Unit 7, PG&E	1972	53.0	SDR
The Geysers, Unit 8, PG&E	1972	53.0	SDR
The Geysers, Unit 9, PG&E	1973	53.0	SDR
The Geysers, Unit 10, PG&E	1973	53.0	SDR
The Geysers, Unit 11, PG&E	1976	106.0	SDR
The Geysers, Unit 12, PG&E	1979	106.0	SDR
The Geysers, Unit 13, PG&E	1980	135.0	SDR
The Geysers, Unit 14, PG&E	1980	110.0	SDR
The Geysers, Unit 15, PG&E	1979	55.0	SDR
The Geysers, Unit 16, PG&E	Future	110.0	SDR
The Geysers, Unit 17, PG&E	1982	110.0	SDR
The Geysers, Unit 18, PG&E	1982	110.0	SDR
The Geysers, Unit 19, PG&E	1982	110.0	SDR
The Geysers, Unit 20, PG&E	Future	110.0	SDR
The Geysers, Unit 21, PG&E	Future	110.0	SDR
The Geysers, Unit 1, NCPA	1981	110.0	SDR
East Mesa, Magmamax	1979	11.2	LDN-B
East Mesa, Republic Geothermal	1980	48.0	LDP-DF
Brawley, So. Cal. Edison	1980	10.0	LD-SF
Puna, HGP Unit	1980	5.0	LDN-SF
Raft River, Binary Unit	1980	3.35	LDP-B
Valles Caldera, Baca No. 1	1982	50.0	LD-SF
Salton Sea (Niland) So. Cal. Edison	1982	10.0	LD-SF
Salton Sea, SDG&E	1982	50.0	LD-__
Heber So. Cal. Edison	1982	50.0	LD-DF
Heber SDG&E	Future	45.0	LD-B
Westmorland	Future	50.0	LD-DF
Roosevelt Hot Springs	Future	52.0	LD-DF
Desert Peak	Future	20.0	
Installed (July 1979) 663.0 Planned (1979 - 1982) 922.55 Future (After 1982) 497.0			

Continued

TABLE C.O-1. WORLDWIDE GEOTHERMAL POWER PLANTS (Continued)

Country/Power Plant	Year of Start-up	Capacity-MW	Power Cycle ^a
World Total Capacity Installed as of July 1979 1,758.9 MW			
World Total Capacity Planned for Operation Between 1979 and 1982 3,519.7 MW			
World Total Future Capacity Planned for Operation After 1982 6,053.7 MW			

^aKey to Power Cycles

Steam-Dominated Sources (SD)

Rankine Cycle (SDR)

Liquid-Dominated, Natural Pressure Sources (LDN)

Single Flash Steam Cycle (LDN-SF)
Dual Flash Steam Cycle (LDN-DF)
Direct Binary Cycle (LDN-B)
Flashed Steam Binary Cycle (LDN-FSB)
Two-Phase Expander Cycle (LDN-TPX)

Liquid-Dominated, Pumped Sources (LDP)

Single Flash Steam Cycle (LDP-SF)
Dual Flash Steam Cycle (LDP-DF)
Direct Binary (LDP-B)
Flashed Steam Binary Cycle (LDP-FSB)
Two-Phase Expander Cycle (LDP-TPX)

REFERENCE

DiPippo, R. January 1980. Geothermal Energy as a Source of Electricity: A Worldwide Survey of the Design and Operation of Geothermal Power Plants. DOE Contract No. A502-76ET28320. DOE/RA/28320-1. Washington, D.C.: Superintendent of Documents.

APPENDIX D

DOE-SPONSORED GEOTHERMAL DIRECT UTILIZATION PROJECTS

D.0 DOE-SPONSORED GEOTHERMAL DIRECT UTILIZATION PROJECTS

This is a summary of U.S. Department of Energy-funded or partially funded programs to utilize direct heat from geothermal sources. Electric generation using a geothermal heat source is not a part of this compilation.

<u>Location</u>	<u>Description</u>
California Brawley	<u>Holly Sugar Geothermal Project</u> This project involves the design, installation, and operation of a geothermal energy system to be used directly for process heat at the Holly Sugar Refinery.
El Centro	<u>Geothermal Core Field Experiment</u> Geothermal resources from the Heber KGRA will be used to provide space cooling and heating, and domestic hot water at El Centro. It is intended that this project serve as the core for a future district heating and cooling system for the city.
Kelley Hot Springs	<u>Swine Raising Complex</u> Geothermal direct energy application for space heating a swine-raising operation and feed production system will be demonstrated. <u>Aquafarm Prawn Raising</u> A commercial fish farmer will expand an existing geothermally supplied system to raise giant Malaysian prawns.
Susanville	<u>District Heating</u> The city will utilize the Susanville geothermal resource to provide space heating to fourteen existing public buildings. A parallel effort will involve expansion of the city system and development of a commercial park.

Location

Description

Colorado
Pagosa Springs

District Heating

In this project, there will be an extensive geothermal heating system within the town of Pagosa Springs, Colorado. This system provides hot water for space heating to 10 public buildings and schools, 54 businesses, and 63 residences.

Idaho
Boise

District Heating

The city of Boise, Idaho, and the Boise Warm Springs Water District will develop a large-scale space heating system using geothermal energy to demonstrate the technical, economic, and organizational feasibility of using low temperature fluids for space heating in downtown Boise and eastern Boise.

Madison County

Municipal and Industrial Uses

In a joint effort by Madison County, Idaho, and AMPCO Foods, Inc., (Rogers Potato Division) this project provides for developing the use of geothermal energy for municipal space heating and industrial food processing.

Montana
Butte

Hospital Heating

In this project, managed by the Montana Energy and MHD Research and Development Institute, utilities at a hospital in Warm Springs, Montana, will be partially converted to use geothermal energy. The project is a continuation of state-funded studies intended to determine the feasibility of converting to a geothermal resource, and to more fully define the resource on hospital property. It will involve drilling of geothermal reinjection wells, design and modifications of the hospital hot water and space heating systems, and will include installation of geothermal heat exchangers and piping.

Location

Description

Nevada
Elko

District Heating (space heating, domestic
water heating, and process heat)

Under the ownership of a heat source company, the geothermal fluid from the Elko, Nevada, KGRA will be used to provide space, service water, and process heating to several buildings within the city.

Reno

Space Heating and Domestic Water Heating

This project involves retrofit of a condominium complex in Reno, Nevada, with a geothermal space and water heating system, utilizing thermal waters in the Moana District, a known geothermal resource.

Oregon
Klamath Falls

District Heating

This project provides for design and construction of an extensive geothermal space heating system in the central business district of Klamath Falls, Oregon. As a city-owned and operated system, it initially will serve fourteen office buildings (city, county, state and federal), with subsequent expansion to 115 private commercial buildings. The system will include two production wells, one reinjection well, approximately two miles of transmission line, retrofitting equipment for all fourteen government buildings, and appropriate control equipment.

Klamath Falls

YMCA Space and Water Heating

A system will be designed and constructed to use geothermal fluids from a recently drilled well to provide space heating and hot water for a YMCA building. The existing fossil fuel system will remain as a back-up or booster system.

Location

Description

Oregon (cont.)
Ontario

Food Processing

In this project, Ore-Ida, Inc., Boise, Idaho, will use a geothermal energy source to retrofit an existing fossil fuel system for food processing and space heating in their existing potato processing plant in Ontario, Oregon. Wells will be drilled to supply fluids for a system to be designed and constructed.

South Dakota
Box Elder

School Heating

In this project, the Douglas School complex in the community of Box Elder, South Dakota, will be heated with hot water from a well drilled into the Madison Aquifer.

Haakon

School Heating

In the project, at the Haakon School District, Haakon, South Dakota, school buildings will be heated with geothermal water from a well to be drilled into the Madison Aquifer. This project provides for design, construction, and start of operations for the complete system.

Pierre

Hospital Heating

St. Mary's Hospital in Pierre, South Dakota, will have its heating system augmented with a system drawing hot water from the Madison Aquifer. The system will be extended to a hospital addition which is under construction.

Rapid City

Agribusiness

Near Rapid City, South Dakota, a low temperature geothermal resource will be used to supply heat to ranch buildings, and will also be used to dry grain and to provide warm stock water for ranch use.

Location

Description

Texas

Corsicana

School and Hospital Heating

Utilizing a known geothermal resource, two buildings, the Navarro College student union and the Navarro County Memorial Hospital, will be retrofitted to augment the existing space and water heating requirements.

Marlin

Hospital Heating

This project will provide space and water heating for the Torbett-Hutchings-Smith Memorial Hospital in Marlin, Texas. Geothermal fluids will be pumped from a known hot water reservoir, using a new well to be drilled as part of this project.

Utah

Salt Lake City

Greenhouse Heating

In this project, six acres of greenhouses will be converted from oil and gas heating to a geothermal system.

Draper

Prison Heating

Utilizing the Crystal Hot Springs geothermal resource, a building of the Utah State Prison will be heated with geothermal fluids. This demonstration will form the nucleus of a system which can be expanded to service the heating requirements of other existing and planned facilities.

Monroe City

District Heating

This project proposes to supply geothermal fluid for space and domestic water heating for three public schools, a church, and 73 residences. An expansion of the system to include other city buildings and commercial operations has been proposed.

APPENDIX E

PRELIMINARY COMPARISON OF GEOTHERMAL/ FOSSIL FUEL GENERATING PLANT AVAILABILITY

E.0

PRELIMINARY COMPARISON OF GEOTHERMAL/FOSSIL FUEL GENERATING PLANT AVAILABILITY

Power plant downtime or outage may result from either scheduled preventive maintenance or failure of a critical component. Estimating outages for a geothermal power plant is highly uncertain because the number of operating geothermal facilities is small and there is no significant statistical basis for making such projections. An outage reporting system similar to those for fossil and nuclear fuel power plants has not been established specifically for geothermal plants. Geothermal power plants report their problems and solutions through the open literature, but are not specific on a unit-by-unit basis. Although general trends are becoming available, exact data from the geothermal industry are not available. Until a larger data base is accumulated for geothermal power plants, some limited comparisons can be made with fossil fuel plants.

Correlation of existing geothermal data with statistical experience from fossil fuel plants should help to determine operations and problems of future geothermal power plants.

The most frequent outage in a fossil fuel power plant is due to boiler-related problems. Fossil fuel boilers require cleaning and inspection and are the leading cause of major power plant failures. However, this type of outage does not apply to geothermal power plants since they do not require boilers.

Turbine-related problems are the second most frequent cause of outages in a fossil fuel plant but are the major cause of outages in geothermal plants. Turbine outage in fossil fuel plants is generally for inspection or control system maintenance. The major causes of turbine outages in geothermal plants are blade corrosion, erosion, or failure. Geothermal power plants that use a binary cycle will transfer many of these corrosion problems to heat exchangers; the turbines in these systems will more closely parallel those in fossil power plants.

Condenser-related problems are the third most frequent cause of downtime at a fossil power plant. Cleaning is the most prevalent reason for outage, but it is of a short duration of about 6 to 8 hours. Condenser problems can be expected to be higher in geothermal power plants because of the chemical composition of geothermal fluids versus fossil fuel steam.

Exciter generator maintenance is the fourth major reason for outages at fossil power plants. Exciter generator maintenance can be expected to increase in a geothermal power plant, particularly when the geothermal fluid contains gaseous sulfur species.

The quality of steam in a geothermal power plant is the key to the amount of downtime incurred by that plant. Based upon experience at

The Geysers and Cerro Prieto, less maintenance is required on major equipment items as the geothermal fluid becomes cleaner. Equipment such as turbines, generators, condensers, pipes, and heat exchangers that are exposed to geothermal fluid should experience more downtime than comparable systems exposed to clean steam in fossil power plants, but downtime will not be lost to boiler problems. More direct correlation between fossil and geothermal power plants is not possible because the predominance of outages is due to boiler problems in fossil plants and because outage data specific for geothermal plants are limited.

The cost of maintenance versus capital costs for equipment is a driving force toward more frequent maintenance outages to detect incipient problems before they become major problems. Better materials may be necessary in many geothermal plant applications; best available materials should be considered for critical applications where maintenance and replacement costs could become prohibitive.

APPENDIX F

RELATIVE ALLOY COST

F.0 RELATIVE ALLOY COSTS

Once the corrosion engineer or plant designer has selected a group of candidate alloys with suitable mechanical properties and corrosion resistance for the proposed application, cost becomes a major factor in the final selection of materials. The final specification of components and materials requires a detailed economic analysis such as is provided in NACE Standard RP-02-72.

Table F.0-1 lists the comparative costs of a number of alloys that might be used in geothermal applications. The costs are normalized to AISI 304L and do not represent dollar values. The relative costs are based on the cost per square foot of large (greater than 10,000 pounds) lots of 0.25-inch plate. These relative costs should be used only in a semi-quantitative sense because many other factors affect the immediate cost of components. For example, a field-constructed, welded carbon steel tank with 0.75-inch walls will probably cost more than an equivalent tank with 0.25-inch stainless steel walls because the carbon steel will require multiple-pass welds while a single-pass weld is required for the stainless steel. In this case the cost of welding overrides the relative cost of material.

Choices between alternative components of the same material can also have a significant effect on cost. A plate heat exchanger with titanium plates will be much less expensive than a tube-and-shell unit of equal heat transfer capacity for two reasons. First, the square footage of titanium will be much less in the plate unit, and second, the cost of fabrication of a tube-and-shell heat exchanger is much greater than the cost of sheet metal plates. It may even be that in some cases, a titanium plate heat exchanger will be competitive in cost with a stainless steel tube-and-shell heat exchanger.

Relative cost per unit of material becomes insignificant when small quantities are required. For example, Stellite No. 6 has a cost of 43 relative to AISI 410 but is widely used as a facing on AISI 410 turbine blades. Relative costs also tend to become insignificant when contingent costs of failure become very large. For example, the corrosion failure of a long lead-time component critical to the operation of a power plant may result in a large expense for replacement power.

TABLE F.0-1. RELATIVE COSTS OF SOME ALLOYS

MATERIAL	APPROXIMATE RELATIVE COST PER SQ. FT. OF 1/4 INCH TYPE 304L PLATE	
	Late 1976	July 1980
Carbon steel	0.25	0.18
Low alloy steel		0.33
Type 410		0.75
E-Brite 26-1 (XM27)		0.83
Type 304L	1.00	1.00
Allegheny-Ludlum 29-4-2 ^a		1.3
Type 316L	1.3	1.5
Ampco 8 (CA613)		2.0
Type 317LM		2.4
90-10 Cupronickel (CA706) ^c	2.1	2.4
70-30 Cupronickel	2.5	2.9
Carpenter 20Cb3		4.3
Titanium (Grade 2)	2.5	4.3
Incoloy 825		4.3
Monel 400	3.5	4.7
Inconel 600	3.9	4.9
TiCode 12 (Grade 12)	3.0	5.1
Ti-0.2 Pb (Grade 7)	5.0	6.9
Inconel 625		9.0
Hastelloy C-276		9.7
Stellite No. 6 ^b		32

^aNot available as sheet. Relative cost estimated from other wrought goods.

^bNot available as sheet. Cost estimate from cost/lb.

^cNot recommended for geothermal applications.

APPENDIX G

COMPOSITIONS OF ALLOYS

G.0 COMPOSITIONS OF ALLOYS

This appendix presents the compositions of alloys, identified by society or trade designations, which are presented in the handbook and Appendix A. The arrangement is alphanumerical.

In a number of cases, partial or abbreviated designations are used in the text, but to minimize listings in this appendix, such alloys are listed only according to the society designation. For example, 1010 carbon steel is listed under AISI (American Iron and Steel Institute) as AISI 1010. Similarly 304 stainless steel, T304, and Type 304 all refer to AISI 304 and the composition is given at the designation. Alloy designations beginning with "A" or "grade" are generally ASTM (American Society For Metals and Testing) and are so located. The prefix ACI designates an American Casting Institute alloy, while CA refers to a designation promulgated by the Copper Association.

Every reasonable effort has been made to assure the completeness and accuracy of this appendix. However, some designations do not control composition and have been omitted, as have generic designations. A few designations, especially foreign, were not readily available.

TABLE G.0-1. COMPOSITION OF ALLOYS

DESIGNATION	CHEMICAL COMPOSITION
15-5 PH	0.07max C, 1.00max Mn, 1.00max Si, 14.00-15.00 Cr, 3.50-5.50 Ni, 2.50-4.50 Cu, 0.15-0.45 (Cb+Ta), bal Fe
17-4 PH	0.05 C, 16.5 Cr, 4.25 Ni, 4.0 Cu, bal Fe
18 Ni Maraging	18.5 Ni, 7.0 Co, 4.5 Mo, 0.026 C, 0.1 Mn, 0.11 Si, 0.22 Ti, 0.003 B, bal Fe
A-286	0.05 C, 15.0 Cr, 26.0 Ni, 1.2 Mo, 2.15 Ti, 0.2 Al, 0.003 B, 0.3 V, bal Fe
ACI CF-3M	0.03max C, 1.50max Mn, 1.50max Si, 17-21 Cr, 9-13 Ni, 2.0-3.0 Mo, bal Fe
ACI CF-8	0.08max C, 1.50max Mn, 2.00max Si, 18-21 Cr, 8-11 Ni, bal Fe
ACI CF-8M	0.08max C, 1.50max Mn, 1.50max Si, 18-21 Cr, 9-12 Ni, 2.0-3.0 Mo, bal Fe
ACI CF-12M	0.12max C, 1.5max Mn, 2.0max Si, 0.04max P, 0.04max S, 18-21 Cr, 9-12 Ni, 2-3 Mo, bal Fe
ACI CF-20	0.20max C, 1.50max Mn, 2.00max Si, 18-21 Cr, 8-11 Ni, bal Fe
AISI H-43	0.55 C, 8.00 Mo, 4.00 Cr, 2.00 V, bal Fe
AISI 202	0.15max C, 7.5-10.0 Mn, 1.00max Si, 0.060max P, 0.030max S, 17.00-19.00 Cr, 4.00-6.00 Ni, 0.25max N, bal Fe
AISI 216	20 Cr, 6 Ni, 2.5 Mo, 8.25 Mn, 0.08max C, bal Fe
AISI 301	0.15max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 16.00-18.00 Cr, 6.00-8.00 Ni, bal Fe
AISI 302	0.15max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 17.00-19.00 Cr, 8.00-10.00 Ni, bal Fe
AISI 304	0.08max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 17.00-19.00 Cr, 8.00-12.00 Ni, bal Fe
AISI 304L	0.03max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 18.00-20.00 Cr, 8.00-12.00 Ni, bal Fe

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
AISI 309	0.20max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 22.00-24.00 Cr, 12.00-15.00 Ni, bal Fe
AISI 310	0.25max C, 2.00max Mn, 1.50max Si, 0.045max P, 0.030max S, 24.00-26.00 Cr, 19.00-22.00 Ni, bal Fe
AISI 314	0.25max C, 2.00max Mn, 1.50-3.00 Si, 0.045max P, 0.030max S, 23.00-26.00 Cr, 19.00-22.00 Ni, bal Fe
AISI 316	0.08max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 16.00-18.00 Cr, 10.00-14.00 Ni, 2.00-3.00 Mo, bal Fe
AISI 316L	0.03max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 16.00-18.00 Cr, 10.00-14.00 Ni, 2.00-3.00 Mo, bal Fe
AISI 317	0.08max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 18.00-20.00 Cr, 11.00-15.00 Ni, 3.00-4.00 Mo, bal Fe
AISI 317LM	0.08max C, 2.00max Mn, 1.00max Si, 0.45max P, 0.30max S, 18.00-20.00 Cr, 12.00-16.00 Ni, 4.0-4.5 Mo, bal Fe
AISI 321	0.08max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 17.00-19.00 Cr, 9.00-12.00 Ni, 5xCmin Ti, bal Fe
AISI 329	See, Carpenter 7 Mo
AISI 347	0.08max C, 2.00max Mn, 1.00max Si, 0.045max P, 0.030max S, 17.00-19.00 Cr, 9.00-13.00 Ni, 10xCmin (Cb+Ta), bal Fe
AISI 403	0.15max C, 1.00max Mn, 0.50max Si, 0.040max P, 0.030max S, 11.50-13.00 Cr, bal Fe
AISI 405	0.08max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 11.50-14.50 Cr, 0.10-0.30 Al, bal Fe
AISI 410	0.15max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 11.50-13.50 Cr, bal Fe
AISI 420	Over 0.15 C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 12.00-14.00 Cr, bal Fe
AISI 430	0.12max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 14.00-18.00 Cr, bal Fe

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
AISI 431	0.20max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 15.00-17.00 Cr, 1.25-2.50 Ni, bal Fe
AISI 434	0.12max C, 0.30-0.90 Mn, 0.50max Si, 0.040max P, 0.030max S, 16.00min Cr, 0.75-1.25 Mo, bal Fe
AISI 440A	0.60-0.75max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 16.00-18.00 Cr, 0.75max Mo, bal Fe
AISI 440B	0.75-0.95max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 16.00-18.00 Cr, 0.75max Mo, bal Fe
AISI 440C	0.95-1.20max C, 1.00max Mn, 1.00max Si, 0.040max P, 0.030max S, 16.00-18.00 Cr, 0.75max Mo, bal Fe
AISI 1010	0.08-0.13 C, 0.30-0.60 Mn, 0.040max P, 0.050max S, bal Fe
AISI 1018	0.15-0.20 C, 0.60-0.90 Mn, 0.040max P, 0.050max S, bal Fe
AISI 1020	0.18-0.23 C, 0.30-0.60 Mn, 0.040max P, 0.050max S, bal Fe
AISI 1035	0.32-0.38 C, 0.60-0.90 Mn, 0.040max P, 0.050max S, bal Fe
AISI 1036	0.30-0.37 C, 1.20-1.50 Mn, 0.040max P, 0.050max S, bal Fe
AISI 1060	0.55-0.66 C, 0.60-0.90 Mn, 0.040max P, 0.050max S, bal Fe
AISI 4118	0.18-0.23 C, 0.70-0.90 Mn, 0.035P, 0.040S, 0.20-0.35 Si, 0.40-0.60 Cr, 0.08-0.15 Mo, bal Fe
AISI 4123	0.23 C, 0.016 S, 0.84 Mn, 0.93 Cr, 0.20 Mo, 0.36 Si, bal Fe
AISI 4130	0.28-0.33 C, 0.40-0.60 Mn, 0.035max P, 0.040max S, 0.20-0.35 Si, 0.80-1.10 Cr, 0.15-0.25 Mo, bal Fe
AISI 4140	0.38-0.43 C, 0.75-1.00 Mn, 0.035 P, 0.040 S, 0.20-0.35 Si, 0.80-1.10 Cr, 0.15-0.25 Mo, bal Fe
AISI 9840	0.38-0.43 C, 0.20-0.35 Si, 0.70-0.90 Mn, 0.40max P, 0.40max S, 0.85-1.15 Ni, 0.70-0.90 Cr, 0.20-0.30 Mo, bal Fe
AISI E52100	0.98-1.10 C, 0.25-0.45 Mn, 0.025 P, 0.025 S, 0.20-0.35 Si, 1.30-1.60 Cr, bal Fe
Alcoa _____	See Aluminum _____

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
Alcoa 35	See Almag 35
Allegheny 304N	0.03 C, 1.5 Mn, 19.0 Cr, 8.0 Ni, 0.25 Mo, 0.25 N, bal Fe
Allegheny 329	0.06 C, 0.40 Mn, 27.0 Cr, 4.5 Ni, 1.5 Mo, bal Fe
Allegheny 329X	0.6 C, 0.40 Mn, 27.0 Cr, 4.5 Ni, 1.5 Mo, 0.18 N, bal Fe
Allegheny 409	0.08 C, 0.50 Mn, 11.0 Cr, 0.25 Ni, 0.25 Mo, 0.8 Ti, bal Fe
Allegheny 444L	0.30max C, 1.0 Mn, 0.040max P, 0.030max S, 1.0max Si, 17.5-19.5 Cr, 1.0max Ni, 1.75-2.50 Mo, 0.10-0.50 Ti, 0.2-0.8 Cb, bal Fe
Allegheny-Ludlum 6X	20 Cr, 24 Ni, 6.0 Mo, 8.25 Mn, 0.08max C, bal Fe
Allegheny-Ludlum 29-4	29 Cr, 4 Mo, 0.15max Ni, 0.01max C, bal Fe
Allegheny-Ludlum 29-4-2	29 Cr, 4 Mo, 2 Ni, 0.01max C, bal Fe
Allegheny-Ludlum 216	20 Cr, 6 Ni, 2.5 Mo, 8.25 Mn, 0.08max C, bal Fe
Alloy 6 X	See Allegheny-Ludlum 6X
Alloy 29-4	See Allegheny-Ludlum 29-4
Almag 35	0.1 Ti, 0.1 Mn, 0.05 Be, 6.5-7.5 Mg, bal Al
Aluminum 1100	0.12 Cu, 99.00% min Al
Aluminum 2024-T3	4.4 Cu, 0.6 Mn, 1.5 Mg, bal Al
Aluminum 3003	0.12 Cu, 1.2 Mn, bal Al
Aluminum 5005	0.8 Mg, bal Al
Aluminum 5052	2.5 Mg, 0.25 Cr, bal Al
Aluminum 6061-T6	0.6 Si, 0.27 Cu, 1.0 Mg, 0.20 Cr, bal Al
Aluminum 6063	0.40 Si, 0.7 Mg, bal Al
Aluminum Brass, Arsenical	See CA-687
Aluminum Bronze	See CA 952

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
Aluminum Bronze D	
See CA-614	
AM-350	0.10 C, 16.5 Cr, 4.3 Ni, 2.75 Mo, bal Fe
AM-355	0.13 C, 0.95 Mn, 0.25 Si, 15.5 Cr, 4.3 Ni, 2.75 Mo, 0.10 N, bal Fe
Ampco 8	
See CA-613	
Ampco 12	
See CA-952	
Ampco 483	9Al, 4.5 Ni, 4 Fe, bal Cu
ARMCO 20-45-5	0.05 C, 5 Mn, 45 Ni, 20 Cr, 2.25 Mo, 0.4 Si, 0.15 Cb, 0.01 P, 0.008S, bal Fe
ARMCO 22-13-5	0.06max C, 20.5-23.5 Cr, 11.5-13.5 Ni, 4.0-6.0 Mn, 1.5-3.0 Mo, 0.2-0.4 N, 0.1-0.3 Cb, 0.1-0.3 V, bal Fe
ARMCO V1312	0.26 C, 0.004S, 0.50 Mn, 1.01 Cr, 0.78 Mo, 0.038 Cb, 0.005max V, 0.21 Si, 0.027 Al, bal Fe
ARMCO V1313	0.26 C, 0.005 S, 0.52 Mn, 1.03 Cr, 0.78 Mo, 0.005max Cb, 0.058 V, 0.22 Si, 0.023 Al, bal Fe
Arsenical Aluminum Brass	
See CA-687	
Arsenical Admiralty Brass	
See CA-443	
ASTM XM-27	
See E- BRITE 26-1	
ASTM A-53	0.08 P, 0.06 S, bal Fe
ASTM A-53 Grade B	0.30 C, 1.2 Mn, 0.05 P, 0.06 S, bal Fe
ASTM A-106 Grade B	0.10min Si, 0.30max C, 0.29-1.06 Mn, 0.048max P, 0.058max S, bal Fe
ASTM A-182 Grade F6a	0.15max C, 1.00 Mn, 0.040max P, 0.030max S, 1.00 Si, 0.05max Ni, 11.5-13.5 Cr, bal Fe
ASTM A-182 Grade F6b	0.15max C, 1.00 Mn, 0.02max P, 0.02max S, 1.0 Si, 1.0-2.0 Ni, 11.5-13.5 Cr, 0.40-0.60 Mo, bal Fe

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
ASTM A-182 Grade F9	0.15max C, 0.30-0.80 Mn, 0.030max P, 0.030max S, 0.50-1.00 Si, 8.0-10.0 Cr, 0.90-1.10 Mo, bal Fe
ASTM A-193 Grade B7	0.37-0.49 C, 0.65-1.10 Mn, 0.04max P, 0.04max S, 0.15-0.35 Si, 0.75-1.20 Cr, 0.15-0.25 Mo, bal Fe
ASTM A-194 Grade 2M	0.40min C, 0.040max P, 0.05max S, bal Fe
ASTM A-204 Grade B	0.20 C, 0.90max Mn, 0.035max P, 0.04max S, 0.15-0.30 Si, 0.45-0.60 Mo, bal Fe
ASTM A-212 and A-212B	See ASTM A-515
ASTM A-216 Grade WCS	0.25max C, 0.04max P, 0.60max Si, 0.05max Cu, 0.050max Ni, 0.40max Cr, 0.25max Mo, 0.03max V, 1.00max Mn, 0.045max S, bal Fe
ASTM A-242 Type 1	0.15max C, 1.00max Mn, 0.15max P, 0.05max S, 0.20min Cu, bal Fe
ASTM A-252	0.05max P, 20 Cr, 34 Ni, 2.5 Mo, 3.5 Cu, 1.0max (Cb+Ta), 0.07max C, bal Fe
ASTM A-285 Grade B	0.22max C, 0.98max Mn, 0.035max P, 0.040max S, bal Fe
ASTM A-286	15 Cr, 25.5 Ni, 1.25 Mo, 1.5 Mn, 0.3 V, 0.3 Al, 2.1 Ti, 0.06 C, bal Fe
ASTM A-296-CF8	See ACI CF-8
ASTM A-296-CF8M	See ACI CF-8M
ASTM A-387 Grade 12	0.17max C, 0.40-0.65 Mn, 0.035max P, 0.04max S, 0.15-0.30 Si, 0.80-1.15 Cr, 0.45-0.60 Mo, bal Fe
ASTM A-515 Grade 65	0.28max C, 0.90max Mn, 0.035max P, 0.04max S, 0.15-0.30 Si, bal Fe
ASTM A-669	See Sandvik 3RE60
ASTM A-690	See Mariner
ASTM B-120	See CA-170 and CA-172
ASTM B-148 Grade 9A	See CA-952

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
ASTM B-168 Grade 41T	72min Ni, 14-17 Cr, 6-10 Fe, 1.0max Mn, 0.15max C, 0.5max Cu, 0.5 Si, 0.015max S
ASTM B-265 Grade 2	0.03max N, 0.1max C, 0.015max H, 0.3max Fe, 0.25max F, 0.250max Other, bal Ti
ASTM B-265 Grade 7	0.03max N, 0.01max C, 0.015max H, 0.30max Fe, 0.25max O, 0.12-0.25 Pd, 0.1 Zr, bal Ti
ASTM B-265 Grade 12	See TiCode 12
CA-122	0.015-0.04 P, Cu + Ag 99.90min
CA-142	0.15-0.50 As, 0.015-0.04 P, Cu + Ag 99.40min
CA-170	1.6-1.8 Be, 0.2min Co, Ni + Fe + Co 0.6max, 0.5max Other, bal (Cu + Ag)
CA-172	1.8-2.0 Be, 0.2min Co, Ni + Fe + Co 0.6max, 0.5max Other, bal (Cu + Ag)
CA-192	0.8-1.2 Fe, 0.01-0.04 P, 0.10 Other, 98.7min Cu
CA-194	2.1-2.6 Fe, 0.03 Sn, 0.05-0.20 Zn, 0.03 Pb, 0.01-0.04 P, 0.15 Other, 97.0min Cu
CA-443	70.0-73.0 Cu, 0.07 Pb, 0.06 Fe, 0.8-1.2 Sn, 0.02-0.10 As, 0.15 Other, bal Zn
CA-608	0.10 Pb, 0.10 Fe, 5.0-6.5 Al, 0.35 As, 0.5max Other, bal Cu
CA-613	3.5 Fe, 0.20-0.50 Sn, 6.0-8.0 Al, 0.5max Other, bal Cu
CA-614	1.5-3.5 Fe, 6.0-8.0 Al, 1.0 Mn, 0.5 Other, bal Cu
CA-630	2.0-4.0 Fe, 0.20 Sn, 9.0-11.0 Al, 1.5 Mn, 0.25 Si, 4.0-5.5 Ni, 0.5max Other, bal Cu
CA-687	76.0-79.0 Cu, 0.07 Pb, 0.06 Fe, 1.8-2.5 Al, 0.02-0.10 As, 0.15 Other, Rem Zn
CA-706	0.05 Pb, 1.0-1.8 Fe, 1.0 Zn, 9.0-11.0 Ni, 1.0 Mn, 0.5max Other, bal Cu

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
CA-715	0.05 Pb, 0.40-0.7 Fe, 1.0 Zn, 29.0-33.0 Ni, 1.0 Mn, 0.5max Other, bal Cu
CA-716	0.05 Pb, 4.8-5.8 Fe, 1.0 Zn, 29.0-33.0 Ni, 1.0 Mn, 0.5max Other, bal Cu
CA-720	0.05 Pb, 1.5-2.5 Fe, 0.30 Zn, 40.0-43.0 Ni, 0.50-1.7 Mn, 0.5max Other, bal Cu
CA-875	0.50 Pb, 12.0-16.0 Zn, 3.0-5.0 Si, 0.5max Other, bal Cu
CA-903	86.0-89.0 Cu, 7.5-9.0 Sn, 0.30 Pb, 3.0-5.0 Zn, 1.0 Ni, 0.15 Fe, 0.05 P
CA-952	86.0min Cu, 2.5-4.0 Fe, 8.5-9.5 Al, 1.0 Other
CA-958	78.0min Cu, 0.02 Pb, 4.0-5.5 Ni, 3.0-5.0 Fe, 8.5-9.5 Al, 0-10 Si, 0-3.5 Mn, 0.50 Other
Carpenter 7 Mo	27 Cr, 4.15 Ni, 2.25 Mo, 3.4 Cu, 0.82 (Cb + Ta), 0.2 Mn, 0.03 C, bal Fe
Carpenter 20	29 Cr, 20 Ni, 2.25 Mo, 3.25 Cu, 0.07 max C, bal Fe
Carpenter 20Cb3	See ASTM-A-252
Carpenter Custom 450	0.05max C, 0.5max Mn, 0.5max Si, 14.5-16.5 Cr, 5.5-7.0 Ni, 0.5-1.0 Mo, 1.25-1.75 Cu, Cbmin=8XC, bal Fe
COR-TEN A	0.10 C, 0.40 Mn, 0.12 P, 0.05 S, 0.50 Si, 1.0 Cr, 0.02min Ti, bal Fe
COR-TEN B	1.2 Mn, 0.52 Cr, 0.02 Ni, 0.01 Mo, 0.31 Cu, 0.05 V, 0.06 Al, 0.07 C, 0.01 P, 0.03 S, bal Fe
Duralumin	3.5-4.5 Cu, 0.3-0.6 Mg, 0.0-0.8 Mn, 0.4-1.0 Fe, 0.0-1.0 Si, bal Al
E-Brite 26-1	26 Cr, 1 Mo, 0.1 Ni, 0.0015 C, bal Fe
FV-520	15.66 Cr, 5.46 Ni, 1.68 Mo, 1.99 Cu, 0.5 C, bal Fe

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
FV-702	15.66 Cr, 2.48 Ni, 1.14 Mo, 0.56 Nb, 0.028 C, bal Fe
Hastelloy B	26-30 Mo, 4-6 Fe, 0.12 C, bal Ni
Hastelloy C	0.08 C, 13-17.5 Cr, 16-18 Mo, 4.5-7 Fe, 3.7-5.3 W, bal Ni
Hastelloy C-4	2.0max Co, 18.0 Cr, 14-17 Mo, 0.70max Ti, 3.0max Fe, 0.08max Si, 1.0max Mg, 0.015max C, 0.04max Others, bal Ni
Hastelloy C-276	14.5-16.5 Cr, 15.0-17.0 Mo, 4.0-7.0 Fe, 3.0-4.5 W, 2.5max Co, 1.0max Mn, 0.02max C, bal Ni
Hastelloy F	0.05 C, 22 Cr, 7 Mo, 0.1 Cu, 17 Fe, 1 W, 3 Co, bal Ni
Hastelloy G	22.5 Cr, 19.5 Fe, 6.5 Mo, 2.5 Co, 2 (Cb+Ta), 2 Cu, 1W, bal Ni
Hastelloy S	15.5 Cr, 14.5 Mo, 1.0 Fe, 0.50 Mn, 0.20 Al, 0.02 La, 0.009 B, 0.40 Si, 0.02max C, bal Ni
Haynes Alloy 20 Mod	22 Cr, 26 Ni, 4 Mo, 0.84 Mn, 0.36 Ti, 0.013 P, 0.010 S, 0.03 C, 0.58 Si, bal Fe
Haynes 25	19-21 Cr, 9-11 Ni, 14-16 W, 2max Fe, 0.15max C, bal Co
Haynes 6R	30 Cr, 3 Ni, 4.5 W, 1.15 C, bal Co
ICI/150	0.010max H, 0.20max Fe, bal Ti
ICI/318A	5.5-6.5 Al, 3.5-4.5 V, bal Ti
IMI318	Ti, 6 Al, 4 V
IMI558	Ti, 4 Al, 4 Mo
IMI679	Ti-2.25 Al, 1 Mo, 11 Sn, 5 Zr, 0.2 Si
Incoloy 800	32.5 Ni, 0.05 C, 0.75 Mn, 46.0 Fe, 0.008 S, 0.50 Si, 0.38 Cu, 21.0 Cr, 0.38 Al, 0.38 Ti
Incoloy 825	21.5 Cr, 30 Fe, 3 Mo, 2.25 Cu, 0.7 Mn, 0.03 Cu, bal Ni
Inconel 600	76 Ni, 0.08 C, 16 Cr, 0.2 Cu, 8 Fe

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
Inconel 625	21.5 Cr, 2.5 Fe, 9 Mo, 3.65 (Cb+Ta), 0.2 Al, 0.2 Ti
Inconel 718	0.04 C, 19.0 Cr, 52.5 Ni, 3.0 Mo, 5.13 (Cb+Ta), 0.9 Ti, 0.5 Al, 18.0 Fe, 0.18 Mn, 0.008 S, 0.18 Si, 0.15 Cu
Inconel X-750	0.04 C, 15.5 Cr, 73.0 Ni, 2.5 Ti, 0.7 Al, 7.0 Fe, 0.5 Mn, 0.005 S, 0.25 Si, 0.25 Cu, 0.95 (Cb + Ta)
K-Monel	See Monel K500
M-152	12 Cr, 2.75 Ni, 1.75 Mo, 0.85 Mn, 0.3 V, 0.14 C, 0.03 N, bal Fe
Mariner	0.40-0.75 Ni, 0.60-0.90 Mn, 0.50min Cu, 0.08-0.15 P, 0.05max S, 0.10max Si, 0.22max C, bal Fe
Monel 400	66.5 Ni, 0.15 C, 31.5 Cu, 1.25 Fe, 1.0 Mn, 0.012 S, 0.25 Si
Monel 404	54.5 Ni, 0.08 C, 0.05 Mn, 0.25 Fe, 0.012 S, 0.05 Si, 44.0 Cu, 0.03 Al
Monel K500	66.5 Ni, 0.13 C, 29.5 Cu, 1.0 Fe, 3.0 Al, 0.75 Mn, 0.005 S, 0.65 Ti
MP-35N	20 Cr, 25 Ni, 9 Fe, 7 Mo, 3 Ti, 0.6 Cb, 0.2 Al, bal Co
MP-159	19.0 Cr, 25.0 Ni, 36.0 Co, 7 Mo, 0.50 Cb, 2.9 Ti, 0.20 Al, 9 Fe
Nickel 200	99.5 Ni, 0.06 C, 0.05 Cu, 0.15 Fe
Ni-O-Nel 825	See Incoloy 825
Ni-Resist Type 1	15 Ni, 1.2 Cr, 1.8 Mn, 6.1 Cu, 2.9 C, bal Fe
Ni-Resist Type 2	3max C, 1.7-2.5 Cr, 18-22 Ni, 1-2.5 Si, 0.8-1.5 Mn, bal Fe
Peraluman 25	2.2-2.8 Mg, 0.15-0.45 Mn + Cr, 0.4max Fe, 0.3max Si, bal Al
Peraluman 30	0.4max Mn, 3-4 Mg, bal Al
Peraluman 35	3.2-3.8 Mg, 0.2-0.4 Mn, 0.1max Ti, 0.4max Fe, 0.05max Cu, bal Al

(Continued)

TABLE G.0-1 (Continued)

DESIGNATION	CHEMICAL COMPOSITION
PH 13-8	0.05max C, 0.1 Mn, 12.75 Cr, 8 Ni, 1.15 Al, 2.25 Mo, 0.01 max N, bal Fe
Rex 326	17 Cr, 17.5 Ni, 3.1 Mo, 3 Mn, 7.1 Co, 2.4 Cb, 0.3 C, bal Fe
Sandvik 2RK65	0.2max C, 1.8 Mn, 19.5 Cr, 25.0 Ni, 4.5 Mo, 1.5 Cu, bal Fe
Sandvik 3RE60	18 Cr, 4.7 Ni, 2.7 Mo, 1.5 Mn, 1.7 Si, 0.03max P, 0.03max S, 0.03max C, bal Fe
Silumin	11-14 Si, bal Al
Stellite No. 1	2.4 C, 33 Cr, 13 W, bal Co
Stellite No. 6	33max Cr, 6max W, 3.5max Fe, 3max Ni, bal Co
Titanium (commerically pure)	See ASTM B-265 Grade 2
Titanium Grade 2	See ASTM B-265 Grade 2
TiCode 12	0.8 Ni, 0.3 Mo, bal Ti
Ti-0.2 Pd	See ASTM B-265 Grade 7
TZM	0.5 Ti, 0.08 Zr, 0.015 C, bal Mo
USS 18-18-2	0.06 C, 18 Cr, 18 Ni, 1.9 Si, bal Fe