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MATERIALS SELECTION GUIDELINES FOR GEOTHERMAL POWER SYSTEMS

First Edition

By
David W. DeBerry
Peter F. Ellis
Colin C. Thomas

September 1978

Work Performed Under Contract No. EG-77-C-04-3904

Radian Corporation
Austin, Texas

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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~~DISCUSSION
DRAFT~~

FIRST EDITION

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FOR GEOTHERMAL POWER SYSTEMS

By:

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September, 1978

Radian Corporation
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Washington, D.C. 20545

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1.0 INTRODUCTION

This manual was prepared for the Department of Energy, Division of Geothermal Energy, by Radian Corporation under Contract No. EG-77-C-04-3904. It presents guidelines for selecting construction materials for power production from liquid-dominated United States geothermal resources.

1.1 Background and Purpose

The goal of the Federal Geothermal Program is to stimulate development of geothermal energy as an economic, reliable, operationally safe, and environmentally acceptable energy source. One aspect of geothermal development that merits attention is that of materials reliability. The objectives of the materials work in the Division of Geothermal Energy are to identify reliable materials for geothermal applications and to help reduce materials costs where they have a significant effect on the cost of utilization of geothermal energy.

The effectiveness of the development of geothermal energy will be determined by the amount of geothermal power that is made available, and this amount will be influenced by the effect that materials problems have on efficiency and downtime. Since every technological effort is limited to some extent by the performance of materials, it is prudent to consider corrosion and materials problems which may limit the development of geothermal energy. The availability of durable and cost-effective construction materials for processing geothermal fluids has a definite impact on the development of geothermal energy.

This manual serves two purposes. First, it is a collection and interpretive summary of existing data on materials performance in geothermal fluids. This data summary will reduce the need for lengthy testing of a large number of materials at each

new geothermal site. It provides a way to help screen potential construction materials through past experience.

The second purpose of the manual is to provide some guidelines for selecting materials for geothermal power plants. The manual establishes a framework of background information that defines an approach to materials selection. It identifies the processes (power cycles) and equipment used to produce electricity, discusses the importance of fluid chemistry, and defines the forms and mechanisms of corrosive attack that can occur in geothermal process streams.

All of this information must be considered in selecting reliable construction materials. Once a geothermal resource is selected for utilization, the power cycle used to produce electricity can be specified. Selection of the power cycle is based on the physical and chemical characteristics of the resource. The steps in the power cycle and the fluid composition can be used to define specific process stream characteristics (e.g., chemical composition, temperature, and fluid velocity). This knowledge of process stream characteristics is essential because it defines the corrosiveness of the various environments to which construction materials will be subjected.

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 resistant to attack at 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. And it is also useful to consider the various 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. In light of all of these sources of information, materials can be selected or the need for further testing can be defined.

Most corrosion failures are due to well known phenomena. Minimizing these failures often depends upon knowing the environment to which the materials are exposed and being aware of past materials experience. Close cooperation is required between corrosion and design engineers. Attention must be given to the characteristics of the geothermal resource, the power cycle to be applied, the durability of potential materials under these conditions, and the economics of these materials. Materials considerations and concern begin during the design phase but should continue through plant construction, start-up, and operation.

1.2 Scope

Geothermal resources include steam-dominated sources, liquid dominated sources, geopressurized sources, and dry (hot rock) sources. There are numerous geothermal resource areas in the United States. Some have been designated as known geothermal resource areas (KGRA's) with potential for the extraction of thermal or electrical energy. This manual considers materials performance in liquid-dominated U.S. resources with sufficient temperatures to be useful for electric power generation. There are seven such liquid-dominated KGRA's for which fluid chemistry is adequately defined. Predictions about the corrosiveness of fluids from these resources can be made based on the fluid characteristics. Corrosion rates have been measured and materials performance tests have been done using fluids from five of the seven KGRA's: Baca, New Mexico; East Mesa, California; Heber, California; Raft River, Idaho; and Salton Sea, California. Test data available for Heber and Baca are rather limited, but Raft River, Salton Sea, and East Mesa have been studied in more detail.

Other useful data on materials performance have been accumulated in saline fluids and operating geothermal power plants. Materials performance data are available for seawater distillation

plants, foreign operating power plants (Cerro Prieto, Mexico and Wairakei, New Zealand) and The Geysers, a power plant utilizing a steam-dominated resource. The information is useful in selecting construction materials for liquid-dominated resources and is included in the Appendix.

The manual summarizes currently available information in a format which allows new information to be added as it becomes available. The manual can be updated in the future by incorporating the results of further testing or data for other KGRA's.

1.3 Summary and Overview

The information in this manual is presented in six sections and six appendices. Section 2 defines and diagrams nine potential power cycles for the generation of electricity from geothermal fluids. 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 corrosivity of individual process streams in power cycles is described based on variations in chemical composition and temperature.

Results of materials performance tests are analyzed based on the chemical composition of the corrosive medium and physical factors such as temperature, duration of exposure, and fluid velocity. These variables must be well defined in order to use test results to predict materials performance in other systems. Geothermal fluids are complex, variable mixtures whose characterization is difficult but essential. Section 3 identifies the key chemical components in geothermal fluids that are

significant in determining corrosivity. The key chemical components in seven United States liquid-dominated KGRA's are defined.

Section 4 gives both summarized and detailed results of materials performance tests in U.S. liquid-dominated resources. The seven KGRA's treated in Section 3 are classified according to relative corrosiveness. Detailed results of corrosion rate measurements are given for Baca, East Mesa, Heber, Raft River, and Salton Sea KGRA's in two formats. The first format is a "screening" table which serves as a guide to the test results. Corrosion results in the screening tables are classified according to detection and severity of attack. The second format includes detailed summaries and discussions of the corrosion rate measurements. The results in Section 4 summarize available test results, but they should be used cautiously. Test conditions, test duration, and completeness of the tests should be considered in applying the results.

Currently available test data are mostly the result of uniform and localized corrosion rate measurements. But there are other kinds of corrosive attack for metals in geothermal fluids. Section 5 describes the various forms and mechanisms of corrosive attack that can occur in geothermal process streams. These generalizations are especially useful when materials must be specified for conditions at which tests have not been done. If the corrosion rate of a material has been tested at the stream conditions of interest, the information in this section is still useful. It explains how fabrication practices, equipment configuration, and operating stresses influence materials performance. And it can be used to predict whether other forms of attack that have not been studied in tests will be important.

Section 6 discusses the application of nonmetallic materials in geothermal environments. Information on the behavior of nonmetallics in these systems is limited.

The appendices contain information on (1) operating experience at geothermal power plants, (2) corrosion in desalination facilities, (3) reliability of geothermal plants, (4) elastomeric materials, (5) comparative alloy costs, and (6) geothermal equipment manufacturers. The corrosion experience from operating geothermal power plants is particularly important to designers of future facilities. Operating experience points out failures and problem areas that may not be encountered in short-term corrosion tests.

2.0

GEOHERMAL 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 geopressured 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.

This section of the manual defines nine potential 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 the same as those for sources recovered by natural pressure except for the pumping equipment. Process flow diagrams, heat balances, and process stream conditions are presented as well as a list of major equipment items 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 corrosivity of individual process streams is described based on variations in chemical composition and temperature.

2.1

Description of Nine Power Cycles

Nine generalized power cycles are potentially applicable to steam- and liquid-dominated geothermal resources. They

TABLE 2-1
POTENTIAL GEOTHERMAL POWER CYCLES

Steam-Dominated Sources

- Rankine Cycle

Liquid-Dominated, Natural Pressure Sources

- Single Flash Steam Cycle
- Dual Flash Steam Cycle
- Direct Binary Cycle
- Flashed Steam Binary Cycle
- Two-Phase Expander Cycle

Liquid-Dominated, Pumped Sources

- Direct Binary Cycle
 - Flashed Steam Binary Cycle
 - Two-Phase Expander Cycle
-

are listed and classified in Table 2-1 according to whether the source is steam- or liquid-dominated and whether it is recovered by natural pressure or pumping.

The power cycles include three major process steps: recovering the geothermal fluid from the well, producing steam or other vapor to drive a turbine, and recovering condensate

and noncondensable gases. 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 separate steam from a liquid-dominated source. Binary cycles use a second liquid as an intermediate heat transfer medium. In direct binary cycles, vapor to drive the turbine is produced from the second liquid by heat exchange with the geothermal fluid. 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 based on the method of recovering the geothermal fluid 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, reducing the cost and complexity of equipment installation and maintenance. Downhole pumping can be used to increase well production, keep noncondensable gases dissolved, and prevent uncontrolled chemical changes in the well head fluid caused by flashing during the recovery process. The economic advantage of higher well flow rates from pumping may offset the cost of installation and maintenance of downhole pumps.

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

Heat balances were calculated using steam table values and ideal cycles. Heat balances and geothermal fluid concentrations for a specific plant design may therefore differ from the range of values given in the flow sheets. The differences arise because of the deviation of geothermal fluid thermodynamic data from the pure water thermodynamic data of the steam tables and the 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 2-2 through 2-10) has been formulated for each of the nine potential power cycles. The equipment item number corresponds to the circled number on the flow sheet for the respective power cycle. The major components within each equipment item have been listed with the associated bulk temperature and geothermal fluid phase in contact with the equipment. Local geothermal fluid velocities within a piece of equipment may differ significantly from the bulk geothermal fluid velocity indicated on the flow sheets. The local velocity must be used for material selection purposes and for design of materials compatibility experiments. Because components of a major piece of equipment will probably be of dissimilar materials, they are listed separately under each equipment item.

The equipment lists are not intended to be all encompassing and do not include every equipment item which may be used. However, equipment types and operating conditions can be selected from the lists which closely correspond to equipment for material selection or material compatibility test programs. For instance, lube oil and hydrogen coolers are similar in service to the conditions found in condensers.

ASSUMPTIONS

1. FLUID AT TURBINE OUTLET 2 $\frac{1}{2}$ LIQUID
2. 10 PSIA PRESSURE DROP FROM STREAM N°1 TO STREAM N°2
3. STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM N° 6.
4. PRESSURE OF 3.0 TO 5.0 IN Hg FOR ALL CONDENSERS
5. 80°F WATER TEMPERATURE RETURN FROM COOLING TOWER.
6. MASS RATIO FOR NON CONDENSABLE GAS IS 0.02 LB./LB. OF STREAM N°1

◆ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM N°1	TEMPERATURE	PRESSURE	VELOCITY	COMMENT
1	1.0	327-373 °F (164-189 °C)	99-180 psia (6.8-1.2 MPa)	50-150 fps (15-45 m/s)	WELL HEAD
2	1.0	319-368 °F (159-187 °C)	89-170 psia (6.1-1.2 MPa)	50-150 fps (15-45 m/s)	PLANT BOUNDARY
3	0.92	319-368 °F (159-187 °C)	89-170 psia (6.1-1.2 MPa)	50-150 fps (15-45 m/s)	AT TURBINE THROTTLE VALVE
4	0.92	115-134 °F (46-57 °C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	250-400 fps (76-122 m/s)	AT TURBINE EXHAUST HOOD
5	0.08	319-368 °F (159-187 °C)	89-170 psia (6.1-1.2 MPa)	50-150 fps (15-45 m/s)	STEAM TO MAIN EJECTORS
6	0.02	115-134 °F (46-57 °C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	30-80 fps (9-24 m/s)	NON CONDENSABLE GASES
7	1.9-2.8	115-134 °F (46-57 °C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	3-10 fps (0.9-3.0 m/s)	CONDENSATE
8	19.6-29.6	115-134 °F (46-57 °C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	3-10 fps (0.9-3.0 m/s)	CONDENSATE
9	21.5-32.4	115-134 °F (46-57 °C)	20-40 psia (1.4-.27 MPa)	3-10 fps (0.9-3.0 m/s)	CONDENSATE
10	20.5-31.4	80 °F (21 °C)	20-40 psia (1.4-.27 MPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER SUPPLY
11	0.02	115-134 °F (46-57 °C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	50-150 fps (15.2-45.1 m/s)	NON CONDENSABLE GAS

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Figure 2-1. Direct Cycle (Rankine) for Steam-Dominated Geothermal Resource

TABLE 2-2
EQUIPMENT LIST FOR DIRECT CYCLE USING STEAM DOMINATED
GEOHERMAL RESOURCE

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

ASSUMPTIONS

1. FLUID AT TURBINE OUTLET 2% LIQUID.
2. ECONOMIC OPTIMUM FLASH POINT OCCURS AT EQUAL TEMPERATURE DIFFERENCE.
 - a. WELL HEAD & FLASH TANK.
 - b. FLASH TANK & CONDENSER - REF BE-455, PG. 4-4
3. STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM No. 8.
4. CONSTANT ENTHALPY ACROSS FLASH TANK.
5. PRESSURE OF 2.5 TO 5.0 IN Hg FOR ALL CONDENSER.
6. 10 psia PRESSURE DROP FROM STREAM No. 1 TO 2.
7. COOLING WATER AT 80°F.
8. MASS RATIO FOR NON CONDENSABLE 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	PRESSURE	VELOCITY	COMMENT
	7%	20%				
1	1.0	1.0	335-500°F (168-260°C)	110-681 psia (76-4.7 MPa)	10-75 fps (3.0-23 m/s)	WELL HEAD
2	1.0	1.0	328-498°F (164-259°C)	100-671 psia (76-4.6 MPa)	10-75 fps (3.0-23 m/s)	PLANT BOUNDARY
3	0.18-0.28	0.30-0.38	225-317°F (107-158°C)	17.9-85.9 psia (12-.59 MPa)	50-150 fps (15.2-46 m/s)	TURBINE INLET CONDITIONS
4	0.72-0.82	0.62-0.70	225-317°F (107-158°C)	17.9-85.9 psia (12-.59 MPa)	5-30 fps (1.5-9.1 m/s)	FLUID DISCARD
5	0.72-0.82	0.62-0.70	225-317°F (107-158°C)	40-400 psia (2.7-2.76 MPa)	3-10 fps (.9-3.0 m/s)	FLUID REINJECTION
6	0.06-0.16	0.18-0.26	109-134°F (43-57°C)	2.5-5.0 IN Hg (8.5-16.9 KPa)	250-400 fps (1.72-2.76 m/s)	TURBINE OUTLET
7	0.12	0.12	225-317°F (107-158°C)	17.9-85.9 psia (12-.59 MPa)	50-150 fps (15.2-46 m/s)	STEAM TO EJECTORS
8	0.03	0.03	109-134°F (43-57°C)	2.5-5.0 IN Hg (8.5-16.9 KPa)	50-150 fps (15.2-46 m/s)	NON CONDENSABLE GAS
9	2.17-2.31	5.5-6.8	109-134°F (43-57°C)	2.5-5.0 IN Hg (8.5-16.9 KPa)	3-10 fps (.9-3.0 m/s)	CONDENSATE
10	2.8-4.9	2.8-4.9	109-134°F (43-57°C)	2.5-5.0 IN Hg (8.5-16.9 KPa)	3-10 fps (.9-3.0 m/s)	—
11	6.1-7.1	8.3-11.7	109-134°F (43-57°C)	16-30 psia (1.1-2.1 MPa)	3-10 fps (.9-3.0 m/s)	COOLING WATER DISCHARGE
12	5.8-6.9	7.9-11.4	80°F (27°C)	40 psia (2.7 MPa)	3-10 fps (.9-3.0 m/s)	COOLING WATER SUPPLY
13	0.03	0.03	115-134°F (46-57°C)	12-20 psia (90-138 KPa)	30-50 fps (9-15.2 m/s)	VENT GAS

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Figure 2-2. Single Flash Steam Cycle for Natural Pressure, Liquid-Dominated Geothermal Resource

EQUIPMENT LIST FOR SINGLE FLASHED STEAM CYCLE USING NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

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

ASSUMPTIONS

1. FLUID AT TURBINE OUTLET 2 % LIQUID.
2. ECONOMIC OPTIMUM FLASH POINT OCCURS AT EQUAL TEMPERATURE DIFFERENCE.
 - a. FIRST STAGE SEPARATOR & SECOND STAGE FLASH.
 - b. SECOND STAGE FLASH & CONDENSING TEMPERATURE-RET BE-ASS P 6-4-4.
3. STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM NUMBER 9.
4. CONSTANT ENTHALPY ACROSS FLASH TANK.
5. PRESSURE OF 3.0 TO 5.0 IN Hg FOR ALL CONDENSERS.
6. 10 PSIa. PRESSURE DROP FROM STREAM NO 1 TO STREAM NO 2.
7. COOLING WATER AT 80°F.
8. MASS RATIO FOR NON CONDENSABLE 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	PRESSURE	VELOCITY	COMMENT
	7%	20%				
1	1.0	1.0	320-400°F (160-204°C)	30-247 psia (.62-1.7 MPa)	3-10 fps (0.9-3.0 m/s)	WELL HEAD
2	1.0	1.0	313-396°F (156-202°C)	80-237 psia (.55-1.6 MPa)	3-10 fps (0.9-3.0 m/s)	PLANT BOUNDARY
3	0.07	0.20	313-396°F (156-202°C)	80-237 psia (.55-1.6 MPa)	50-150 fps (15.2-45.7 m/s)	FIRST STAGE STEAM
4	0.93	0.80	313-396°F (156-202°C)	80-237 psia (.55-1.6 MPa)	3-10 fps (0.9-3.0 m/s)	FIRST STAGE FLUID
5	0.01-0.14	0.08-0.12	214-265°F (101-130°C)	15.2-38.5 psia (1.0-.26 MPa)	50-150 fps (15.2-45.7 m/s)	SECOND STAGE STEAM
6	0.79-0.88	0.68-0.72	314-365°F (151-130°C)	15.2-38.5 psia (1.0-.26 MPa)	3-10 fps (0.9-3.0 m/s)	SECOND STAGE FLUID TO REINJECTION/DISPOSAL
7	0.05-0.18	0.16-0.20	115-134°F (46-57°C)	3.0-5.0 IN Hg (46-57 KPa)	250-400 fps (76.2-122 m/s)	TURBINE EXHAUST NOOD
8	1.6-3.8	5.8-9.1	115-134°F (46-57°C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	3-10 fps (0.9-3.0 m/s)	MAIN CONDENSER OUTLET
9	0.03	0.03	115-134°F (46-57°C)	3.0-5.0 IN Hg (10.1-16.9 KPa)	30-50 fps (9-15.2 m/s)	NON CONDENSABLE GASES
10	0.2	0.12	313-396°F (156-202°C)	80-237 psia (.55-1.6 MPa)	50-150 fps (15.2-45.7 m/s)	STEAM TO EJECTORS
11	5.8-7.7	7.0-9.35	115-134°F (46-57°C)	10-40 psia (.69-2.7 KPa)	3-10 fps (0.9-3.0 m/s)	CONDENSATE & COOLING WATER
12	5.6-7.5	6.7-9.1	80°F (27°C)	20-40 psia (1.38-2.7 KPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER
13	0.03	0.03	115-134°F (46-57°C)	12-20 psia (.80-1.38 KPa)	30-50 fps (9-15.2 m/s)	VENT GAS

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Figure 2-3. Dual Flash Steam Cycle for Natural Pressure, Liquid-Dominated Geothermal Resource

TABLE 2-4

EQUIPMENT FOR DUAL FLASHED STEAM CYCLE USING NATURAL
PRESSURIZED, LIQUID-DOMINATED GEOTHERMAL RESOURCE

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

ASSUMPTIONS

1. 10 psia pressure drop from stream N° 1 to stream N° 2.
2. MASS RATIO FOR NON CONDENSABLE GAS IS 0.0-0.05 LB./LB. OF STREAM N° 1.

◇ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM N° 1	TEMPERATURE	PRESSURE	VELOCITY	COMMENTS
1	1.0	230-400°F (110-204°C)	21-247 psia (0.14-1.65 MPa)	3-10 fps (0.9-3.0 m/s)	WELL HEAD
2	1.0	198-396°F (92-202°C)	10-182 psia (0.07-1.25 MPa)	3-10 fps (0.9-3.0 m/s)	PLANT BOUNDARY
3	0.90-1.0	90-180°F (32-82°C)	10-110 psia (0.07-0.76 MPa)	3-10 fps (0.9-3.0 m/s)	REINJECTION FLUID AT PLANT BOUNDARY
4	0.0-0.05	90-160°F (32-71°C)	15-25 psia (0.10-0.17 MPa)	30-50 fps (9-15.2 m/s)	NON CONDENSABLE GASES

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Figure 2-4. Direct Binary Cycle for Natural Pressure, Liquid-Dominated Geothermal Resource

TABLE 2-5
EQUIPMENT LIST FOR DIRECT BINARY CYCLE USING
NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

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

ASSUMPTIONS

- ECONOMIC OPTIMUM FLASH POINTS OCCUR AT EQUAL TEMPERATURE DIFFERENCE.
 - FIRST STAGE SEPARATOR & SECOND STAGE FLASH.
 - SECOND STAGE FLASH & BINARY CONDENSER. REF DE-455 PG. 4-6.
- 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 NON CONDENSABLE GAS IS 0.03 LB./LB. OF STREAM NO. 1.

◇ STREAM NUMBERS

○ EQUIPMENT NUMBERS

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO. 1		TEMPERATURE	PRESSURE	VELOCITY	COMMENT
	7%	20%				
1	1.0	1.0	230-500°F (110-260°C)	20.9-681 psia (1.4-4.7 MPa)	10-75 fps (3.0-23 m/s)	WELL HEAD
2	1.0	1.0	197-498°F (92-253°C)	10.9-671 psia (0.7-4.6 MPa)	10-75 fps (3.0-23 m/s)	PLANT BOUNDARY
3	0.07	0.20	197-498°F (92-253°C)	10.9-671 psia (0.7-4.6 MPa)	50-150 fps (15.2-45.7 m/s)	FIRST STAGE STEAM
4	0.93	0.80	197-498°F (92-253°C)	10.9-671 psia (0.7-4.6 MPa)	3-10 fps (0.9-3 m/s)	FIRST STAGE FLUID
5	0.04-0.21	0.03-0.18	156-307°F (69-153°C)	4.3-74.4 psia (0.3-5.1 MPa)	50-150 fps (15.2-45.7 m/s)	SECOND STAGE STEAM
6	0.78-0.89	0.62-0.77	156-307°F (69-153°C)	4.3-74.4 psia (0.3-5.1 MPa)	3-10 fps (0.9-3 m/s)	SECOND STAGE FLUID
7	0.08-0.25	0.20-0.35	136-287°F (58-142°C)	2.6-54.9 psia (0.2-4.0 MPa)	3-10 fps (0.9-3 m/s)	STEAM CONDENSATE RETURN
8	0.03	0.03	130-250°F (54-121°C)	15-30 psia (1.0-2.1 MPa)	30-50 fps (9-15.2 m/s)	NON CONDENSABLE GAS
9	0.97	0.97	130-250°F (54-121°C)	2.6-55 psia (0.2-4.0 MPa)	3-10 fps (0.9-3 m/s)	REINJECTION FLUID

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Figure 2-5. Flashed Steam Binary Cycle for Natural Pressure, Liquid-Dominated Geothermal Resource

TABLE 2-6

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

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

ASSUMPTIONS

1. 20 % VAPOR AT WELL HEAD.
2. ISENTROPIC EXPANSION THROUGH NOZZLE AND TURBINE TO 3.5 IN Hg ABS.
3. 10 psia PRESSURE DROP FROM STREAM NR 1 TO STREAM NR 2.
4. STEAM REQUIRED FOR EJECTORS EQUALS 4 TIMES THE MASS OF STREAM NR 1.
5. PRESSURE OF 3.5 IN Hg FOR ALL CONDENSERS.
6. COOLING WATER AT 80°F.
7. MASS RATIO FOR NON CONDENSABLE GAS IS 0.25 LB./LB. OF STREAM NR 1.

◇ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM N° 1	TEMPERATURE	PRESSURE	VELOCITY	COMMENT
1	1.0	302-467°F (150-242°C)	69-500 psia (4.7-3.4 MPa)	10-75 fps (3.0-23 m/s)	WELL HEAD
2	1.0	292-465°F (144-241°C)	59-490 psia (4.1-3.4 MPa)	10-75 fps (3.0-23 m/s)	PLANT BOUNDARY
3	.20	292-465°F (144-241°C)	59-490 psia (4.1-3.4 MPa)	50-150 fps (15.2-45.1 m/s)	STEAM
4	.80	292-465°F (144-241°C)	59-490 psia (4.1-3.4 MPa)	3-10 fps (0.9-3.0 m/s)	GEOTHERMAL FLUID
5	AS REQUIRED	—	64-495 psia (4.4-3.4 MPa)	3-10 fps (0.9-3.0 m/s)	SCALE PRECIPITATE MODIFICATION AS REQD.
6	.80	292-465°F (144-241°C)	59-490 psia (4.1-3.4 MPa)	3-10 fps (0.9-3.0 m/s)	MODIFIED FLUID
7	10.4-12.9	80°F (27°C)	15-30 psia (1.0-.21 MPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER SUPPLY
8	3.2-3.4	120°F (49°C)	20-100 psia (1.4-.69 MPa)	3-10 fps (0.9-3.0 m/s)	MIXED C.W. & MODIFIED FLUID
9	0.1	292-465°F (144-241°C)	59-490 psia (4.1-3.4 MPa)	50-150 fps (15.2-45.1 m/s)	EJECTOR STEAM
10	0.025	80-120°F (27-49°C)	15-30 psia (1.0-.21 MPa)	50-150 fps (15.2-45.1 m/s)	NONCONDENSABLE GAS
11	2.9-10.1	80-120°F (27-49°C)	15-30 psia (1.0-.21 MPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER RETURN

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Figure 2-6. Two-Phase Expander Cycle for Natural Pressure, Liquid-Dominated Geothermal Resource

TABLE 2-7
EQUIPMENT LIST FOR TWO PHASE EXPANDER CYCLE USING
NATURAL PRESSURE, LIQUID-DOMINATED GEOTHERMAL RESOURCE

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

STREAM NUMBER	MASS FLOW lb./lb. OF STREAM (1)	TEMPERATURE	PRESSURE	VELOCITY	COMMENTS
1	1.0	212-562 °F (100-350 °C)	20-2800 psia (0.14-19.3 MPa)	5-10 f/s (0.9-3.0 m/s)	WELL HEAD
2	1.0	212-562 °F (100-350 °C)	20-2800 psia (0.14-19.3 MPa)	5-10 f/s (0.9-3.0 m/s)	PLANT BOUNDARY
3	1.0	80-180 °F (27-82 °C)	10-2800 psia (0.07-18.6 MPa)	5-10 f/s (0.9-3.0 m/s)	SPENT FLUID

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◇ STREAM NUMBER

○ EQUIPMENT NUMBER

Figure 2-7. Direct Binary Cycle for Pumped, Liquid-Dominated Geothermal Resource

TABLE 2-8
EQUIPMENT LIST FOR DIRECT BINARY CYCLE USING
PUMPED, LIQUID-DOMINATED GEOTHERMAL RESOURCE

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

ASSUMPTIONS

1. FLUID AT WELL HEAD 20 w/o VAPOR.
2. ECONOMIC OPTIMUM FLASH POINTS OCCUR AT EQUAL TEMPERATURE DIFFERENCE.
 - a. WELL HEAD TEMPERATURE & SECOND STAGE FLASH.
 - b. SECOND STAGE FLASH & CONDENSER TEMPERATURE. REF. BE-455 pg 4-9.
3. 10 psia. PRESSURE DROP FROM STREAM NO 1 TO STREAM NO 2.
4. CONSTANT ENTHALPY ACROSS FLASH TANK.
5. CONDENSING TEMPERATURE 115°F.
6. MASS RATIO FOR NON CONDENSABLE GAS, 0.03 LB./LB. OF STREAM NO 1.

◇ STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB. OF STREAM NO 1	TEMPERATURE	PRESSURE	VELOCITY	COMMENT
1	1.0	230-662°F (110-350°C)	21-2398 psia (.14-16.5 MPa)	3-10 fps (.9-3.0 m/s)	WELL HEAD
2	1.0	198-661°F (92-349°C)	11-2388 psia (.07-16.5 MPa)	3-10 fps (.9-3.0 m/s)	PLANT BOUNDARY
3	.20	198-661°F (92-349°C)	11-2388 psia (.07-16.5 MPa)	50-150 fps (15.2-45.7 m/s)	FIRST STAGE STEAM
4	.80	198-661°F (92-349°C)	11-2388 psia (.07-16.5 MPa)	3-10 fps (.9-3.0 m/s)	FIRST STAGE FLUID
5	.03-.18	156-306°F (69-152°C)	4.3-73 psia (.03-.50 MPa)	50-150 fps (15.2-45.7 m/s)	SECOND STAGE STEAM
6	.62-.77	156-306°F (69-152°C)	4.3-73 psia (.03-.50 MPa)	3-10 fps (.9-3.0 m/s)	SECOND STAGE FLUID
7	.20-.35	136-286°F (58-141°C)	12.6-54 psia (.09-.37 MPa)	3-10 fps (.9-3.0 m/s)	STEAM CONDENSATE
8	.03	130-250°F (56-121°C)	5-30 psia (.03-.207 MPa)	50-150 fps (15.2-45.7 m/s)	NON CONDENSABLE GASES

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Figure 2-8. Flashed Steam Binary Cycle for Pumped, Liquid-Dominated Geothermal Resource

TABLE 2-9

**EQUIPMENT LIST FOR FLASHED STEAM BINARY CYCLE USING
PUMPED, LIQUID-DOMINATED GEOTHERMAL RESOURCE**

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

ASSUMPTIONS

1. ISENTROPIC EXPANSION THRU NOZZLE AND TURBINE TO 3.5 IN Hg ABS.
2. MASS RATIO FOR NON CONDENSABLE GAS IS .025 LB./LB. OF STREAM No. 1.

 STREAM NUMBER

○ EQUIPMENT NUMBER

STREAM NUMBER	MASS RATIO LB./LB OF STREAM NO 1	TEMPERATURE	PRESSURE	VELOCITY	COMMENT
1	1.0	302-662 °F (150-350 °C)	175-2800 psia (121-19.3 MPa)	3-10 fps (0.9-3.0 m/s)	WELL HEAD
2	1.0	295-662 °F (146-350 °C)	150-2800 psia (1.03-19.3 MPa)	3-10 fps (0.9-3.0 m/s)	PLANT BOUNDARY
3	AS REQUIRED	—	155-2300 psia (1.07-20.0 MPa)	3-10 fps (0.9-3.0 m/s)	SCALE/PRECIPTATE MODIFICATION AS REQD
4	4.1-12.2	80 °F (27 °C)	20-30 psia (1.38-2.07 KPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER SUPPLY
5	4.2-12.6	95-120 °F (35-49 °C)	10-30 psia (0.689-2.07 KPa)	3-10 fps (0.9-3.0 m/s)	COOLING WATER RETURN
6	0.6-0.9	95-120 °F (35-49 °C)	20-100 psia (1.38-6.89 KPa)	3-10 fps (0.9-3.0 m/s)	MIXED C.W. & MODIFIED FLUID
7	0.0025-0.035	280-662 °F (138-350 °C)	140-2800 psia (0.96-19.3 MPa)	3-10 fps (0.9-3.0 m/s)	MODIFIED FLUID
8	0.025	80-120 °F (27-49 °C)	10-30 psia (0.689-2.07 KPa)	50-150 fps (15.2-45.1 m/s)	AIR CONDENSABLE GAS

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Figure 2-9. Two-Phase Expander Cycle for Pumped, Liquid-Dominated Geothermal Resource

TABLE 2-10
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	a Casing	✓		✓	302-662
		b Production Pipe	✓		✓	
		c Compactor	✓		✓	
		d Pump	✓			
2	Wellhead	a Valves (gate/globe/needle)	✓		✓	302-662
		b Gauges (press/temp)	✓		✓	
		c Tees & Crosses	✓		✓	
		d Blow-out Preventer	✓		✓	
3	Mixing Chamber	a Press. Vessel	✓		✓	280-662
		b Mixing Elements	✓		✓	
		c Internal Baffles	✓		✓	
		d Valves (gates/globe/needle)	✓		✓	
		e Gauges (press/temp)	✓		✓	
		f Metering Device	✓		✓	
4	2Ph Exp Nozzle	a Venturi	✓	✓	✓	280-662
		b Valves (gate/globe/needle)	✓	✓	✓	
		c Gauges (press/temp)	✓	✓	✓	
5	Impulse Turbine	a Casing & Fixed Blades			✓	Indeter- minate
		b Rotor, Blades, & Shrouds			✓	
		c Seals			✓	
		d Nozzle Block			✓	
		e Valves (gate/globe/needle)			✓	
		f Relief Valve			✓	
		g Gauges (press/temp)			✓	
		h Strainer			✓	
6	Barometric Cond.	a Gaskets	✓	✓	✓	>120
		b Baffles	✓	✓	✓	
		c Valves (gate/globe/needle)	✓	✓	✓	
		d Gauges (press/temp)	✓	✓	✓	
		e Ejector	✓	✓	✓	
		f Seals	✓	✓	✓	
		g Non-condensable Gas Piping	✓	✓	✓	
		h Spray Jets & Piping	✓			
7	Inter Condenser	same as 6	✓	✓	✓	>120
8	After Condenser	same as 6	✓	✓	✓	>120
9	Condensate Pump	a Casing	✓			95-120
		b Shaft	✓			
		c Impeller	✓			
		d Packing	✓			
		e Glands, Lantern Rings, Bushings	✓			
		f Sealing Rings	✓			
		g Gauges (press/temp)	✓			

2.2 Effect of Geothermal Fluid Properties on the Applicability of Power Cycles

The applicability of a power cycle to a specific geothermal resource depends on characteristics of the fluid. Properties that influence the applicability of a power cycle include (1) total dissolved solids and scaling potential, (2) pressure and temperature, (3) the liquid to vapor ratio, (4) chemical composition of the fluid, and (5) concentration of noncondensable gases. The influence of these properties is discussed in a general way in this section. The following Section 2.3 describes some potential materials performance problems associated with fluid characteristics for specific process streams in three power cycles.

Scaling in geothermal systems is a complex phenomenon which is outside the scope of this discussion except as it affects corrosion and cycle selection. Scaling tendencies of a given resource depend on its temperature and the concentration of relatively minor concentration species: silica, calcium, carbonate, sulfate and heavy metal ions. The tendency for silica scaling increases with decreasing temperature, but pH effects are also important and these depend on both temperature and processing conditions. The pH of most fluids increases on flashing. The scaling problem depends heavily on the chemical composition of the individual KGRA fluid. Scaling affects cycle choice, but requires a number of tradeoffs and cannot be generalized.

The Rankine Cycle is applicable to steam-dominated sources. Eight cycles are presented for liquid-dominated sources, five for sources recovered by natural pressure and three for sources that require pumping to increase well flow

rate or to keep noncondensable gases dissolved. As discussed above, liquid-dominated sources can be treated in flashed steam, binary, or two-phase cycles.

Flashed steam cycles are useful for liquid-dominated resources with fluid temperatures above 180°C, but they are extremely sensitive to noncondensable gases. The energy obtained from noncondensable gases in a turbine is small compared to the energy available from steam. So a turbine which handles steam and noncondensable gases must be larger (and more expensive) than one with an equivalent rating which handles steam alone. Noncondensable gases must be continuously removed from condensers and heat exchangers. Flashed steam cycles are applicable for resources with noncondensable gas concentrations less than three weight percent (3 wt. %). Intermediate binary cycles are a useful alternative to use of gas ejectors and compressors for resources with higher noncondensable gas concentrations.

2.3 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 local fluid velocity. Section 3 describes the key chemical species that determine the corrosiveness of geothermal fluids. This section describes how the temperature, local 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.

The following sections identify potential materials 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 are representative of those for other cycles. The discussions refer to stream numbers on the flow diagrams in Section 2.2. The absence of oxygen in the process streams is assumed unless otherwise stated. As discussed further in Section 5, prevention of oxygen inleakage is a major design goal for any geothermal process.

2.3.1 Dual Flashed Steam Cycle

Figure 2-3 shows the process streams in a typical dual flash steam cycle.

Stream 1. Wellhead Fluid - This is the highest temperature saline stream in the process. The aqueous pH is relatively low due to dissolved CO_2 and H_2S . Corrosivity is determined primarily by the combined effects of temperature, pH, and chloride concentration. Materials problems may be increased by localized flashing leading to high local fluid velocities. This can cause erosion/corrosion by entrained solids or impingement. Several observed failures of pipe elbows may have been caused by such attacks. Scale deposition from solution may increase localized corrosion problems.

Steps must be taken to prevent severe corrosion due to oxygen inleakage during a plant outage. The sinking of fluid level in a well during prolonged shutdown can cause air inleakage and considerable damage to well piping.

Stream 2. Fluid from Pretreatment to First Stage Separator - The change in corrosiveness of this stream depends on the pretreatment method. Acidification to reduce scaling can increase the corrosion rate of carbon steel by a factor of

three or four per unit decrease in pH. Removal of H_2S would generally reduce corrosion of downstream components.

Streams 3 and 10. First Stage Steam to Turbine and Air Ejectors - The high temperature steam will normally contain significant quantities of CO_2 , some H_2S , and lesser amounts of NH_3 . Efficient steam separation and scrubbing to remove as much entrained liquid as possible are desirable. This stream should be kept as dry and oxygen-free as possible.

Stream 4. First Stage Flashed Liquid to Second Stage Flash Tank - The liquid stream loses a large fraction of its dissolved CO_2 and H_2S on flashing, and the temperature decreases. Loss of dissolved CO_2 and H_2S increases the pH. These effects should offset the increase in chloride concentration due to steam loss, and Stream 4 should be less aggressive than Stream 2.

Stream 5. Second Flash Steam - This steam should contain significantly less CO_2 than the high temperature steam. Relatively more NH_3 may be present due to the higher pH of the flashed liquid. The risk of localized condensation is greater for this stream. Entrained liquid removal, dryness, and non-aeration are still important.

Stream 6. Second Stage Flashed Liquid to Disposal - This stream has undergone changes similar to those described under Stream 4. The absolute changes in CO_2 , H_2S , and pH may be less than for the first flash liquid. The temperature drop is significant, however, and this stream should be less aggressive even though chloride concentration is higher. Oxygen in-leakage is an increasing problem since pressure is approaching atmospheric. At this point, the fluid is still hot enough to

cause stress corrosion cracking of susceptible materials in the presence of small amounts of oxygen.

The post-treatment process (most likely for prevention of injection well plugging) is poorly defined at present. 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 solution and does not necessarily require high concentrations of sulfide.

Stream 7. Turbine Exhaust to Condensers - This stream will contain little chloride but significant quantities of CO_2 , H_2S , and in some cases NH_3 from absorption of part of these gases by steam condensate. The aggressiveness of this stream depends on the concentrations of these gases (and their related species) in the liquid and especially on the pH resulting from mixing the "acidic" CO_2 and H_2S species with "alkaline" NH_3 . The main corrosion problem at Cerro Prieto was in the cooling water system, where condensate was employed in the cooling towers (Appendix A).

Emission of H_2S from condensate in cooling towers may be a problem. Addition of ferric salts was used as an emission control method at the Geysers. Although moderately effective as an H_2S control method, the addition of ferric salts significantly increased corrosion and sludge disposal problems.

Streams 8, 11, 12. Condensate and Cooling Water - As noted above, the condensate and cooling water streams can present significant problems. Cooling tower aeration can make these problems more acute both by introducing oxygen and by causing the oxidation of sulfide to sulfate which will make the

stream more acidic. Possible solutions include:

- 1) increase of the pH of the circulating stream,
- 2) addition of corrosion inhibitors, and
- 3) use of nonmetallic materials or corrosion resistant alloys.

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

2.3.2 Direct Binary Cycle

Process streams for this cycle are shown in Figure 2-4. The comments for Streams 1 and 2 prior to the heat exchanger are the same as for the dual flash cycle.

Stream 3 in this cycle is saline fluid from the binary heat exchanger. Chemical changes occurring in the saline/binary heat exchanger are more difficult to predict than in the flashed steam case. Since less flashing occurs, the concentrations of CO_2 and H_2S will not be decreased as much, and the pH increase due to CO_2 and H_2S release will be less than in the flashed steam case. Temperature effects on aqueous equilibria and gas solubility will be more important and may tend to make the cooler fluid more acidic.

The precautions given for the cooled, flashed fluid stream generally apply to Stream 3 of the direct binary cycle. The binary cycle Stream 3 may have relatively lower pH and higher dissolved H_2S and CO_2 concentrations. Combined with lower temperature, these factors could make it more aggressive with regard to sulfide stress cracking or hydrogen blistering. Non-metallic materials may be useful for some applications in this environment.

Conventional materials will most likely be used for the binary fluid equipment. The thin-walled parts of the heat exchanger must be resistant to pitting and crevice corrosion to prevent leakage of hot saline fluid to the binary loop. Resistance of the material to solutions used for scale removal must also be considered.

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 H_2S emissions. Although probably lower in H_2S and CO_2 than the flashed steam condensate, this stream is more saline. Cooling tower aeration will make it more aggressive due to the added dissolved oxygen and the lower pH from sulfide oxidation. Control methods given for condensate Steams 8, 11, 12 in the dual flashed steam cycle are recommended.

2.3.3 Flashed Steam Binary Cycle

The effects of processing on the geothermal fluid are the same as for the dual flashed steam cycle.

The main distinction from a corrosion standpoint is that steam is used in the binary heat exchangers instead of saline liquid.

The use of steam circumvents scaling problems but does not prevent corrosion problems. Steam containing H_2S and CO_2 has been found to be innocuous at Wairakei and Cerro Prieto when "dry," but high corrosion rates for several materials have been found at Salton Sea. Steam condensate can be a corrosive liquid depending on the concentrations of dissolved H_2S , CO_2 ,

and NH_3 and the resulting pH. Efficient steam separation and scrubbing are important to minimize chloride carry-over from the liquid.

The discussion of flashed geothermal liquid for cooling water in Section 2.3.1 also applies to flashed steam binary cycles.

3.0

CHEMICAL COMPOSITION OF GEOTHERMAL FLUIDS FROM A CORROSION STANDPOINT

Results of materials performance tests are analyzed based on the chemical composition of the corrosive medium and physical factors such as temperature, duration of exposure, and fluid velocity. These variables must be well defined in order to use test results to predict materials performance in other systems. Geothermal fluids are complex, variable mixtures whose characterization is difficult but essential. This section identifies chemical components in geothermal fluids that are significant in determining corrosivity. The utility of existing chemical composition data for predicting fluid corrosivity is considered. A summary of chemical composition of fluids from seven U.S. geothermal resources is presented.

3.1

Key Corrosive Chemical Species

Geothermal fluids contain six key chemical species that produce a significant corrosive effect on metallic construction materials. These key species were identified from an analysis of corrosion literature and an examination of the data on chemical composition of fluids from liquid-dominated geothermal resources. They are the most common and aggressive corrosive species and therefore the ones that should be analyzed in all geothermal environments.

Geothermal fluids are complex chemical solutions containing many different species. The six most significant species and their important gas and liquid phase chemical forms are listed below:

- Hydrogen ion

- Chloride ion
- Hydrogen sulfide
- Carbon dioxide, Carbonate and Bicarbonate ion
- Ammonia, Ammonium ion
- Sulfate ion

The identification of these species as the most significant is complicated by the following factors:

- Materials respond to a given chemical species in different ways and degrees.
- The importance of a given species often depends on its concentration relative to other species.
- The interaction of two or more chemical species may give results different from those obtained with the individual species.
- The temperature dependence of corrosion by a given species is often undefined.
- The importance of a given species depends on the form of attack (uniform, localized, cracking).

Other chemical species that are less common or aggressive can also produce corrosive effects in some geothermal fluids. Examples are fluoride ion, heavy metals, and boron. Oxygen, while not normally a component of high-temperature geothermal fluids, greatly increases their corrosive effects. The accidental

introduction of oxygen to a geothermal process stream has produced very serious corrosion problems in existing geothermal electric power plants.

Scaling or solids deposition is another aspect of geothermal fluid chemistry that influences materials performance. Precipitation of liquid phase species in solution or on equipment surfaces can influence corrosion rates and cause erosion. The composition of the scale-forming solids and the rate of precipitation depend on fluid composition and specific process stream conditions, so scale-forming species are not included in the list of key species.

Some generalizations about the corrosive effects of the key species, oxygen, and transition metal ions on construction materials are given in the following paragraphs. This subject is treated in more depth in Section 5.0, which provides details about the forms of attack for specific metals and alloys.

Hydrogen ion (pH) - The general corrosion rate of carbon steels increases rapidly with decreasing pH, especially below pH 7. Passivity of many alloys is pH dependent. Breakdown of passivity at local areas can lead to serious forms of attack, e.g., pitting, crevice corrosion, and stress corrosion cracking.

Chloride - Chloride causes local breakdown of passive films which protect many metals from uniform attack. Local penetration of this film can cause pitting, crevice corrosion, or stress corrosion cracking. Uniform corrosion rates can also increase with increasing chloride concentration, but this action is generally less serious than local forms of attack.

Hydrogen Sulfide - Probably the most severe effect of H_2S is its attack on certain copper and nickel alloys. These metals have performed well in seawater but are practically

unuseable in geothermal fluids containing H_2S . The effect of H_2S on iron-based materials is less predictable. Accelerated attack occurs in some cases and inhibition in others. High-strength steels are often subject to sulfide stress cracking. H_2S may also cause hydrogen blistering of steels. Oxidation of H_2S in aerated geothermal process streams increases the acidity of the stream.

Carbon Dioxide - In the acidic region, CO_2 can accelerate the uniform corrosion of carbon steels. The pH of geothermal fluids and process streams is largely controlled by CO_2 . Carbonates and bicarbonates can display mild inhibitive effects.

Ammonia - Ammonia can cause stress corrosion cracking of copper alloys. It may also accelerate the uniform corrosion of mild steels.

Sulfate - 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.

Oxygen - The addition of small quantities of oxygen to a high-temperature geothermal system can greatly increase the chance of severe localized corrosion of normally resistant metals. The corrosion of carbon steels is sensitive to trace amounts of oxygen.

Transition Metal Ions - "Heavy" or transition metal ions might also be included as key species. Their action at low concentrations on most construction materials is ill-defined. However, the poor performance of aluminum alloys in geothermal fluids may be due in part to low levels of copper or mercury in these fluids. Salton Sea geothermal fluids contain many transition

metal ions at greater than "trace" concentrations. Some oxidized forms of transition metal ions (Fe^{+3} , Cu^{+2} , etc.) are corrosive, but these ions are present in the lowest oxidation state (most reduced form) in geothermal fluids. Oxygen can convert Fe^{+2} to Fe^{+3} which is another reason to exclude oxygen from geothermal streams.

3.2 Key Corrosive Chemical Species in Selected KGRA's

The concentrations of key species in geothermal fluids must be defined in order to use the results of materials performance tests. If corrosion test conditions are accurately and completely defined, then the results can be used to predict materials performance in other systems. So it is useful to consider the applicability of existing composition data. Analyses of springs or other related surface sources are of no use for predicting corrosion in geothermal power cycles. Although a large number of geothermal well analyses have been completed (LA-312), much of these data are of limited utility for predicting materials performance. The utility of the data may be limited for the following reasons:

- One or more of the key species were not analyzed (H_2S and NH_3 are the most common omissions).
- Other important factors such as temperature, well flow rate, or flow time were not specified.
- The accuracy of the analytical results was not indicated. Error limits were not specified, and the method of sample acquisition and analyses were not described. Obtaining a representative sample of downhole fluid presents a number of experimental difficulties (NE-302).

- Chemical analyses were done on flashed fluid, and the conditions under which flashing occurred were either uncontrolled or unspecified.

Flashing causes changes in the pH and the concentrations of H_2S , CO_2 and NH_3 in the fluid. If these components are measured in the flashed fluid, the results are not representative of concentrations in the unflashed fluid. The usefulness of flashed fluid data is limited if they cannot be used to calculate concentrations in the unflashed streams. The flashing conditions must be specified and the flashed steam must be analyzed for H_2S , CO_2 and NH_3 . Such data are scarce and hard to obtain because of difficulties in the sampling procedures.

A partial list of information required with any reported analysis is given below.

- well shut-in periods,
- recent reservoir engineering,
- total stabilization time,
- fluid flow rate from well,
- identification of two-phase flow, and
- specific sampling procedures and conditions.

Typical concentrations of key corrosive chemical species in fluids from seven "known geothermal resource areas" (KGRA's) are shown in Tables 3-1 and 3-2. These data are the result of a review and analysis of all available chemical composition data for U.S. and foreign geothermal resources. The review showed that data characterizing key species are available for seven U.S. KGRA's and two foreign resources (Cerro Prieto, Mexico and Wairakei, New Zealand, see Appendix A). KGRA's for which reasonably complete characterizations of key species are available include Salton Sea, East Mesa, Heber, Mono-Long Valley, Baca (Valles Caldera), Beowawe, and Raft River.

TABLE 3-1. TYPICAL CONCENTRATIONS OF KEY CORROSIVE CHEMICAL SPECIES IN FLUID FROM SEVEN KGRA'S

KGRA	Temperature °C and location	Properties of the Geothermal Resource						Fluid Description	Comments
		pH	Cl ⁻	Total CO ₂	Total H ₂ S	Total NH ₃	SO ₄ ⁼		
Salton Sea, Ca.	250 (bore-hole)	5.2	115,000	1,000	10-30	300	20	unflashed well-head fluid	These data are the results of extensive analyses of several wells, so they are representative of the resource. Variations occur; CO ₂ concentrations as high as 10,000 ppm have been measured.
East Mesa, Ca.	180-200 (bore-hole)	5.7	11,000	800	3	41	20	unflashed well-head fluid	The data are for well 6-1, which has received the most study. It may not be typical of the field. Higher pH (6.5) and lower Cl ⁻ and CO ₂ have been measured at other wells. The fluid also contains about 9 ppm Fe.
Reber, Ca.	180-200 (bore-hole)	7.1	9,000	180	~2	13	152	unflashed well-head fluid	These data are from two separate analyses of fluid from the well Nowlin 1. The fluid also contains about 4 ppm Fe.
Mono-Long Valley, Ca.	175 (bore-hole)	6.5	227	180	14	0.1	96	unflashed well-head fluid	These data are for well Endogenous 4. It is the only well for which H ₂ S concentrations were measured. Results of analyses of other species in fluids from other wells in the area agree with the results for this well.
Baca (Valles Caldera) N.M.	171 (well-head at 110 psig)	6.8	3,770	128	6	-	59	flashed fluid	These data represent the results of three similar analyses of flashed fluid from well Baca 11. They are not representative of values in the unflashed fluid.
Geopline, Nev.	132 (well-head)	9.3	50	209	6	3	89	flashed fluid	These data are representative of wells Vulcan 2, 3, and 4. Data for H ₂ S, CO ₂ , NH ₃ , and pH are not representative of the unflashed fluid.
Raft River, Id.	146 (bore-hole)	7.2	780	60	0.1	2	61	unflashed fluid	These data are for well ERGE 1 which is well characterized. Well ERGE 2 has a similar composition. Well ERGE 3 has a similar composition except for Cl ⁻ , which is about 3 times higher.

TABLE 3-2. TYPICAL COMPOSITION OF NONCONDENSABLE GASES IN SEVEN KGRA'S

KGRA	Concentration of Noncondensable Gases	Composition of Noncondensable Gases (volume % of gas)							
		CO ₂	H ₂ S	NH ₃	N ₂	Ar	H ₂	He	CH ₄
Salton Sea, Ca.	0.2-0.3 vol % of steam	80.-90.	0.3	-	c	-	-	-	0.5
East Mesa, Ca.	no data available								
Heber, Ca.	0.2 wt % of total flow	1.4-9.5	-	-	70-92	1.0	1.8-3.8	<0.01	2.9-15
Mono-Long Valley, Ca.	0.87 wt % of steam	98.2	1.7	-	-	-	-	-	-
Baca (Valles Caldera), N. M.	1.72 vol % of steam 4.10 wt % of steam	(47,390) ^a	(567)	(6)	(109)	-	(4)	-	(6)
Beowawe, Nev.	0.19 wt % of steam	97.6	0.93	1.06	-	-	-	-	0.39
Raft River, Id.	1.6 vol % of total flow	7.2 ^b	0.022	-	90.16	1.89	0.148	0.049	0.369

^a units are ppm in steam

^b Measured oxygen concentration was 0.459 vol % of gas. Sample was probably contaminated with air.

^c balance is N₂ + Ar

Table 3-1 gives typical concentrations of key species in unflashed fluid from all but two of the KGRA's. Data for Baca and Beowawe are from analyses of flashed fluid, so the values for H_2S , CO_2 , NH_3 , and pH are not representative of those in the unflashed fluid. Flashed steam was analyzed as shown in Table 3-2.

The comments in Table 3-1 indicate the degree to which these data can be considered typical of the entire field. Some KGRA's have been characterized in more detail than others. Variations in the results of analyses of fluids from different wells in a field are quite common. These variations make it difficult to define typical or representative concentrations of key species, especially if only one well has been studied. The data for Salton Sea, Raft River, and Mono-Long Valley are based on multiple analyses of several wells, so there is a good basis for assuming they are typical of the field. On the other hand, data for East Mesa and Heber are from the analysis of a single well, so there is some possibility that the data are not typical of the entire field. Other wells at East Mesa have lower chloride and CO_2 concentrations and slightly higher pH values than those given here, but corrosion testing has been done in the fluid shown.

Table 3-2 shows typical concentrations of noncondensable gases in flashed steam or total fluid from six of the seven KGRA's. Concentrations of nine components are given. These data are particularly significant for Beowawe and Baca KGRA's because the key species concentrations in Table 3-1 are for flashed fluid.

This section of the manual gives both summarized and detailed results of materials performance tests in U.S. liquid-dominated resources. First an overview is presented which defines four sources of information about corrosion tests on metallic construction materials in saline fluids. The relative usefulness of the test results for materials selection purposes is discussed. Then the form in which tests results are presented is explained to show where to find the results and how to interpret them. Sections 4.1 through 4.5 contain the actual test results for U.S. liquid-dominated KGRA's. Results of tests and operating experience for other fluids are included in the appendices.

There are four sources of information about actual materials performance in saline fluids:

- Results of corrosion tests at five U.S. liquid-dominated KGRA's (presented in this section)
- Practical operating experience from two foreign power plants using liquid-dominated geothermal resources (presented in Appendix A)
- Results of corrosion tests at The Geysers, a U.S. steam-dominated geothermal resource (presented in Appendix A)
- Results of corrosion tests in seawater desalination plants (presented in Appendix B).

Previous experience is of the utmost importance in corrosion engineering. Development of U.S. liquid-dominated geothermal resources is in the early stages, but power plants using this type of resource are already operational at Wairakei, New Zealand and Cerro Prieto, Mexico. Appendix A contains a summary of corrosion data from these two sites. The data from Cerro Prieto are particularly important because the plant is located on the California-Mexico border. The geothermal fluid properties at Cerro Prieto are similar to those in some California resource areas.

The United States has an operating power plant at the Geysers, a steam-dominated resource. Operating experience from the Geysers plant is of interest because it provides data on corrosion in steam and condensate. But these streams have lower chloride concentrations than equivalent streams from liquid-dominated resources.

Many materials have been tested in seawater desalination plants at temperatures up to 120°C. Test results may indicate some materials suitable for lower temperature process streams in geothermal power cycles. General findings and comments on applicability to geothermal systems are given in Appendix B.

4.1 Corrosion Tests at U.S. Liquid-Dominated KGRA's

Emphasis in this section is placed on recent corrosion tests at U.S. liquid-dominated KGRA's. Some generalizations are made about materials performance in fluids from seven KGRA's. Test results for five of the KGRA's are presented in separate sections.

Wellhead fluids from seven liquid-dominated KGRA's have been classified in three broad categories: most corrosive, moderately corrosive, and least corrosive. The information available about corrosion in these fluids is still too limited to allow accurate predictions about the performance of specific materials. The broad categories are useful because they provide a framework for comparing results for different resources.

4.1.1 Most Corrosive: Salton Sea

High uniform corrosion rates and localized attack of plain carbon steels by Salton Sea fluids have been observed. Many commonly used alloys are subject to localized attack in these fluids. Resistant materials are available, but the apparent marginal usefulness of carbon steel is of concern.

The chloride concentration of most Salton Sea fluids is about ten times higher than that of the next highest KGRA. CO_2 and H_2S concentrations are fairly high but not exceptional compared to Cerro Prieto and Wairakei fluids. The ammonia concentration does appear to be high compared to these sources and other KGRA's. The pH (5.2) of this resource is relatively low, but acidification to pH ~ 4.5 may be needed to control scaling. The sulfate concentration is negligible compared to other corrosive components in this fluid.

4.1.2 Moderately Corrosive: Baca, East Mesa, Heber, Mono-Long Valley, Raft River

The compositions and limited corrosion results for these resources indicate that their behavior should be similar. Their compositions are bracketed by those at Wairakei and Cerro Prieto for which long-term operating experience is available. However, simple power cycles are used at these plants and materials selection may be critical for more complex cycles.

The most extensive data are available for Raft River. Limited data are available for East Mesa (well 6-1), Baca, and Heber. Corrosion data are not available for Mono-Long Valley. A brief overview of results and reasons for the moderately corrosive classification is given below.

Available results indicate that the uniform corrosion rate of plain carbon steels should be about 2-10 mpy in these fluids. Pitting and crevice corrosion were observed at Raft River and crevice corrosion at East Mesa. These forms of corrosion will probably limit the use of carbon steels to relatively thick-walled equipment.

Material selection for thin-walled and critical components will be more difficult. Test results at Raft River are instructive since extensive localized corrosion of many "resistant" alloys was observed even in this relatively low chloride (~780 ppm) and near neutral (pH 7.2) fluid. Shorter duration tests at East Mesa and Heber show similar results. Preliminary indications are that attack is no worse at these sites than at Raft River. Alloys such as Type 316 and 26Cr-1Mo are subject to localized attack. More detailed information is presented in Section 4.5.

The low H_2S content of Raft River fluids is probably unusual, and the copper-based alloys found to be acceptable may be subject to H_2S attack in most other fluids. Performance of copper-nickel alloys was poor even in Raft River fluid.

As noted in Section 3, Table 3-1, most new wells at East Mesa have significantly lower chloride concentrations and somewhat higher pH values than well 6-1 where most corrosion testing has been done.

Corrosion data in Baca wellhead fluid are limited. Corrosion in the flashed steam from this source has received more attention. The relatively low pH of the flashed fluid at Baca indicates potential corrosion problems. If the pH of unflashed fluid is much lower, well piping could be subject to serious attack. The H_2S content of unflashed fluid is of similar concern.

Mono-Long Valley is tentatively included in this class even though it has a low chloride concentration. The pH of this fluid is lower, and wellhead temperature is higher than Raft River. Combined with relatively high H_2S levels, these factors make it potentially as corrosive as other members of this class.

4.1.3 Least Corrosive: Beowawe

The chloride concentration of Beowawe fluids is low and pH of the flashed fluid is high (pH ~9.3). These factors should make this fluid less corrosive to iron-based alloys than those in the moderately corrosive category. However, the H_2S content of this fluid will make it aggressive toward certain copper-based and nickel-copper alloys. Sulfide stress cracking and hydrogen blistering of certain steels are also possible. The chloride content is high enough to cause stress corrosion cracking and localized attack of susceptible alloys, especially in the presence of oxygen.

Tables 4-1 and 4-2 show the ferrous and nonferrous materials that have been tested at eight geothermal resources including Cerro Prieto, Wairakei, the Geysers, and five liquid-dominated U.S. KGRA's. Table 4-3 describes the nominal compositions of brand name alloys that have been tested.

TABLE 4-1
FERROUS MATERIALS TESTED AT GEOTHERMAL SITES

	Wairakei, N.Z.	Cerro Prieto, Mex.	The Geysers, California	Salton Sea, California	East Mesa, California	Heber, California	Boft River, Idaho	Laca (Vallias Caldera) N.M.
Cast Irons								
Gray cast iron	Tested		Tested				Tested	
Mi-silicon cast iron	Tested							
3Ni-cast iron	Tested		Tested					
Mi-resist cast iron*	Tested							
Type 2 -Mi-resist*	Tested		Tested					
22Ni-ductile cast iron			Tested					Tested
Low Alloy Steels								
Carbon (1010, 1018, 1020)	Tested		Tested	Tested	Tested	Tested	Tested	Tested
Low-carbon		Tested						
4130				Tested	Tested		Tested	
4140								
0.7Mo	Tested							
1.5Mo	Tested							
1.5Cr								Tested
4.7Ni	Tested							
9Cr							Tested	
1Cr-0.2Mo (S00-500)				Tested				
1Cr-0.5Mo (ASTM A-387 Gr 64)				Tested				Tested
2.5Cr-1Mo				Tested				
3.1Cr-0.4Mo	Tested							
3.7Cr-8Mo				Tested				
5.6Cr-0.5Mo				Tested				
9Cr-1Mo				Tested				
1.7Mo-0.3Mo	Tested							Tested
1Cr-1.3Mo-0.25V		Tested						
1.5Cr-1Al-0.25Mo		Tested						Tested
1.8Cr-3.5Ni-0.4Mo-0.1V		Tested						Tested
2.75Ni-0.5Mo-0.1V								Tested
ASTM A-285		Tested						
CDR-TEN B			Tested	Tested			Tested	
CDR-TEN				Tested				
Mariner								
Stainless Steels								
AISI Type 302					Tested			
AISI Type 304	Tested		Tested				Tested	
AISI Type 316	Tested		Tested			Tested	Tested	
AISI Type 316L								
AISI Type 317LM				Tested	Tested	Tested		Tested
AISI Type 403								
AISI Type 409	Tested		Tested				Tested	
AISI Type 410	Tested		Tested					
AISI Type 430	Tested		Tested		Tested		Tested	
AISI Type 440								Tested
AISI Type 616			Tested					
17-4 PH			Tested					
ACL CF-8	Tested		Tested					
ACL CF-8M	Tested		Tested					
Allegheny-Ludlum 216*							Tested	
Allegheny-Ludlum 6X*				Tested			Tested	
Allegheny-Ludlum 29-4*				Tested			Tested	
Allegheny-Ludlum 29-4-2*				Tested			Tested	
Carpenter 20*					Tested	Tested		Tested
Carpenter 20Cb 3*	Tested		Tested	Tested		Tested		Tested
Carpenter 7Mo*					Tested			
Sandvik 3RE60*				Tested	Tested	Tested		
E-Brite 26-1*								Tested
M152*								Tested
A286*								
Bax 326*	Tested							
12Cr		Tested						Tested
12Cr-4Ni								
12Cr-0.2Al		Tested						
12Cr-1Mo-1W		Tested						
13Cr	Tested							
13Cr-3Mo	Tested							
15Cr-1.7Mo		Tested						
17Cr	Tested							
17Cr-2Ni	Tested							
18Cr-35Ni	Tested							
18Cr-8Ni	Tested							
18Cr-8Ni-1Nb	Tested							
18Cr-8Ni-3Mo	Tested							
18Cr-12Ni-1Nb	Tested							
18Cr-12Ni-2Mo	Tested							
Haynes Alloy 20 Mod						Tested		

*The compositions of these alloys are given in Table 4-3.

TABLE 4-2
NONFERROUS MATERIALS TESTED AT GEOTHERMAL SITES

	Wairakei, N. Z.	Carro Prieto Mexico	The Geysers California	Salton Sea California	East Mesa, California	Heber, California	Naft River Id.	Boca (Valles Calders) N. M.
Nickel Based Alloys								
Monel 400*	Tested		Tested	Tested	Tested	Tested	Tested	Tested
K-Monel*	Tested			Tested	Tested			Tested
Inconel X-750* (Inconel X)				Tested	Tested			Tested
Inconel 600* (Inconel)	Tested						Tested	Tested
Inconel 625*				Tested	Tested	Tested		Tested
Incoloy 825* (Ni-C-Mo)	Tested							Tested
Hastalloy F*	Tested							
Hastalloy G*				Tested		Tested	Tested	
Hastalloy S*				Tested	Tested	Tested		
Hastalloy C-276*				Tested	Tested	Tested		
Copper Based Alloys								
Copper	Tested	Tested		Tested	Tested			
Cu-2Fe				Tested	Tested			
Be-copper	Tested							
Admiralty Brass			Tested					Tested
Naval Brass		Tested						
90-10 Brass					Tested			
70-30 Brass	Tested				Tested			
60-40 Brass	Tested							
Muntz Metal							Tested	
22 Ni-6Pb-Brass								Tested
Ampco 8 (7Al-bronze)*							Tested	
Ampco 12 (9Al-bronze)*							Tested	
Ampco 483 (9Al-4.5Ni-bronze)*							Tested	
10Al-bronze			Tested					Tested
10Al-5Ni-bronze								
5Al-10Ni-bronze	Tested							
Silicon bronze	Tested							
Phosphor bronze	Tested							
85-5-5-5 bronze*			Tested					
9-10 cupronickel			Tested					
70-30 cupronickel				Tested	Tested		Tested	Tested
Titanium Based Alloys								
Titanium (commercially pure)	Tested			Tested	Tested	Tested	Tested	Tested
Ti-1.7W				Tested	Tested			
Ti-1.5W				Tested	Tested			
Ti-10V				Tested	Tested			
Ti-0.2Pd				Tested				
Ti Code 12*				Tested		Tested		
Ti-6Al-4V				Tested				
Ti-8Al-1Mo-1V				Tested				
Ti-4Al-3Mo-1V				Tested				
Ti-5Al-2.5 Sn								Tested
Aluminum Based Alloys								
1100		Tested	Tested				Tested	
2024			Tested	Tested	Tested			
3003	Tested		Tested					
5005					Tested			
5052							Tested	
6061			Tested	Tested	Tested		Tested	
Cobalt Based Alloys								
MP35N*				Tested				
Stellite #6*		Tested						
Haynes 60*							Tested	
Haynes 25*				Tested				
Molybdenum Based Alloy								
TM2				Tested	Tested			

* The compositions of these alloys are given in Table 4-3.

TABLE 4-3

COMPOSITIONS OF BRAND NAME ALLOYS

		<u>Standards Designation</u>	
<u>Iron Base</u>			
Ni-resist cast iron			15Ni, 1.2Cr, 1.8Mn, 6.1Cu, 2.9C
Type 2 Ni-resist cast iron			18-22Ni, 2.2-3.0Cr, 1-1.5Mn, 2.2-3C
COR-TEN B steel			1.2Mn, 0.52Cr, 0.02Ni, 0.01Mo, 0.31Cu, 0.05V, 0.06Al, 0.07C, 0.01P, 0.03S
Mariner Steel	ASTM A690		0.40-0.75Ni, 0.60-0.90Mn, 0.50Cu (min), 0.08-0.15P, 0.05S (max), 0.10Si (max), 0.22 (max)
Allegheny-Ludlum 216			20Cr, 6Ni, 2.5Mo, 8.25Mn, 0.08C (max)
Allegheny-Ludlum 6X			20Cr, 24Ni, 6.0Mo, 8.25Mn, 0.08C (max)
Allegheny-Ludlum 29-4			29Cr, 4Mo, 0.15Ni (max), 0.01C (max)
Allegheny-Ludlum 29-4-2			29Cr, 4Mo, 2Ni, 0.01C (max)
Carpenter 20			29Cr, 20Ni, 2.25Mo, 3.25Cu, 0.07C (max)
Carpenter 7Mo	AISI Type 329		27Cr, 4.15Ni, 2.25Mo, 3.4Cu, 0.82Cb + Ta, 0.2Mn, 0.03C
Sandvik 3RE-60	ASTM A669		18Cr, 4.7Ni, 2.7Mo, 1.5Mn, 1.7Si, 0.03P (max), 0.03S (max), 0.03C (max)
E-Brite 26-1			26Cr, 1Mo, 0.1Ni, 0.0015C
M 152			12Cr, 2.75Ni, 1.75Mo, 0.85Mn, 0.3V, 0.14C, 0.03N
A 286			15Cr, 25.5Ni, 1.25Mo, 1.5Mn, 0.3V, 0.3Al, 2.1Ti, 0.06C
Rex 326			17Cr, 17.5Ni, 3.1Mo, 3Mn, 7.1Co, 2.4Nb, 0.3C
Haynes 20 Mod			22Cr, 26Ni, 4Mo, 0.84Mn, 0.36Ti, 0.013P, 0.010S, 0.03C, 0.58Si
<u>Nickel Base</u>			
Monel 400			31Cu, 1.35Fe
K-Monel			30Cu, 1Fe, 2.75Al, 0.5Ti, 0.5Mn
Inconel X-750			15.5Cr, 7.0Fe, 0.7Al, 2.5Ti, 0.95Nb + Ta, 0.50 Mn, 0.04C
Inconel 600			16Cr, 8Fe, 0.2Cu, 0.08C
Inconel 625			21.5Cr, 2.5Fe, 9Mo, 3.65Nb + Ta, 0.2Al, 0.2Ti
Incoloy 825			21.5Cr, 30Fe, 3Mo, 2.25Cu, 0.7Mn, 0.03Cu
Ni-o-nel			(replaced by Incoloy-825)
Hastelloy F			22Cr, 17Fe, 7Mo, 3Co, 1W, 0.1Cu, 0.05C
Hastelloy G			22.5Cr, 19.5Fe, 6.5Mo, 2.5Co, 2Nb + Ta, 2Cu, 1W
Hastelloy S			15.5Cr, 14.5Mo, 1.0Fe, 0.50Mn, 0.20Al, 0.02La, 0.009B, 0.40Si, 0.02C (max)
Hastelloy C-276			14.5-16.5Cr, 15.0-17.0Mo, 4.0-7.0Fe, 3.0-4.5W, 2.5Co (max), 1.0Mn (max), 0.02C (max)
<u>Copper Base</u>			
Ampco 8	CDA 613		7Al, 2.5Fe bronze
Ampco 12	CDA 952		9Al, 3Fe, bronze
Ampco 483	CDA 483		9Al, 4.5Ni, 4Fe bronze
85-5-5-5 bronze			85Cu, 5Pb, 5Zn, 5Sn
<u>Titanium Base</u>			
TiCode-12	ASTM B 265 Gr. 12		0.8Ni, 0.3Mo
<u>Cobalt Base</u>			
MP 35N			20Cr, 25Ni, 9Fe, 7Mo, 3Ti, 0.6Nb, 0.2Al
Stellite #6			33Cr (max), 6W (max), 3.5Fe (max), 3Ni (max)
Haynes 25			19-21Cr, 9-11Ni, 14-16W, 2Fe (max), 0.15C (max)
Haynes 68			30Cr, 3Ni, 4.5W, 1.15C
<u>Molybdenum Base</u>			
TZM			0.5Ti, 0.08Zr, 0.015C

Detailed results of corrosion tests are given for Baca, East Mesa, Heber, Raft River and Salton Sea KGRA's in the following sections. The results are presented in two forms. The first is a "screening" table which serves as an index or guide to the test results. The screening tables are based on the numerical results of corrosion tests. Both general corrosion rate and localized corrosion (pitting, crevice corrosion, and stress corrosion cracking) are shown. Materials are classified in one of four categories (A through D) based on measured general corrosion rates as shown below:

<u>Category</u>	<u>Measured Rate of General Corrosion</u>
A	rate < 1 mpy
B	1 < rate ≤ 10 mpy
C	10 < rate < 50 mpy
D	rate ≥ 50 mpy

Observations about localized corrosion in the screening tables are limited to "detected" (indicated by X) or "not detected" (indicated by N).

Results of laboratory tests are given in addition to field test results. Laboratory results are given in parentheses.

In addition to the screening tables, detailed summaries of the corrosion test results are provided. General and localized corrosion rates are presented in tabular 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. But localized growth rate is difficult to predict, and the assumption

of a linear growth rate is not always accurate. In actuality, 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.

4.2 Results of Corrosion Tests at Baca (Valles Caldera) New Mexico KGRA

Corrosion data for Baca flashed fluids and steam are summarized in Tables 4-4 and 4-5. The limited number of test results was obtained in flashed wellhead fluid and steam; results are unavailable for unflashed wellhead fluid. Localized corrosion rates are available only for flashed steam.

4.2.1 Test Conditions

Two series of corrosion tests were made at the Baca, New Mexico geothermal site. The geothermal fluid underwent flashing in the bore, and the composition of the two streams used in the corrosion tests is given in Table 4-6.

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 (TO-089).

In another test series, candidate turbine materials were exposed to demisted steam at 171°C (340°F) and 110 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 were exposed to air-contaminated moisture for 10 days. This represents worst case conditions (TO-089).

The testing of turbine materials also included corrosion fatigue tests. Specimens were exposed to demisted steam and then subjected to cyclic stress, and the decrease in fatigue endurance limit (defined in Section 5) was determined.

TABLE 4-4

CORROSION SCREENING RESULTS FOR BACA (VALLES CALDERA) FLASHED WELLHEAD FLUIDS

	Nonaerated Fluid				Aerated Fluid			
	Uniform Corrosion	Pitting	Crevice Corrosion	SCC	Uniform Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel	C*	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-

*Other data indicate that a "B" rating is more probable.

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but ≤ 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but ≤ 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate > 50 mpy (> 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected

Refer to Table 4-7 for more complete data.

TABLE 4-5

CORROSION SCREENING RESULTS FOR BACA (VALLES CALDERA)STEAM AFTER FLASHING

	<u>Demisted Steam</u>			
	<u>Uniform Corrosion</u>	<u>Pitting</u>	<u>Crevice Corrosion</u>	<u>SCC/ SSC</u>
<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 - general corrosion rate ≤ 1 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected

Refer to Table 4-8 for more complete data.

TABLE 4-6
COMPOSITION OF FLASHED STEAM AND FLUID FROM WELL NO. 11 USED
IN CORROSION TESTS AT BACA, NEW MEXICO KGRA

<u>Characteristics of</u> <u>Fluid After Flashing</u>		<u>Characteristics of</u> <u>Flashed Steam</u>	
Wellhead Temperature (°C at 110 psig)	171	Noncondensable Gases	{ wt% 2.44-3.99*
Conductance (μmhos/cm)	10,630-11,230		{ vol% 1.02-1.68*
Specific Gravity	1.008	pH of Condensate	4.3-4.9
pH	6.6-7.1	CO ₂ (ppm by wt)	33,700-47,390
Cl ⁻ (ppm)	3,400-4,400	H ₂ S (ppm by wt)	290-570
Total CO ₂ (ppm)	57-128	NH ₃ (ppm by wt)	1.5-6.0
Total H ₂ S (ppm)	1.5-6.	CH ₄ (ppm by wt)	0.-6.
SO ₄ ⁻² (ppm)	50-70	Cl ⁻ (ppm by wt from carryover, est.)	10
Suspended Solids (ppm)	520-690		
Total NH ₃	Not measured		

*Based on total production.

Reference: TO-089

4.2.2 Results

Results of tests on heat exchanger materials are shown in Table 4-7. 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 4-8. Twenty alloys were tested, and only carbon steel showed a general corrosion rate greater than 1.0 mpy. Pitting was a major problem; only A286 showed no pitting. The low hardness (Rc~23) Type 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.

Because of test conditions, stress corrosion cracking could not be distinguished from sulfide stress cracking. Most of the alloys tested were Rc~22 or higher and failed the severe U-bend stress corrosion test. These materials did better at lower applied stress. These materials might also give good service at higher applied stress if they were of lower strength/hardness levels.

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. None of the specimens showed evidence of significant metal loss of the braze alloy itself.

The results of corrosion-fatigue tests are expressed as the ratio of fatigue endurance limit before exposure to FEL after exposure. The decrease in fatigue endurance limit (FEL)

TABLE 4-7
RESULTS OF CORROSION TESTS OF HEAT EXCHANGER
MATERIALS AT BACA, NEW MEXICO KGRA^a

<u>Material Tested</u>	<u>Corrosion Rate in Steam (mpy)</u>	<u>Corrosion Rate in Steam with En-trained Fluid (mpy)</u>	<u>Corrosion Rate in Flashed Fluid (mpy)</u>
<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

^aTests were done at 171°C 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. Results are from reference T0-089. Pitting, crevice corrosion and SCC data were not reported. Metallographic examination showed no indication of intergranular corrosion.

^bMost corrosion was on the tube side of the specimen (exposed to cold aerated water).

Reference: T0-089

TABLE 4-8
CORROSION TEST RESULTS FOR TURBINE MATERIALS IN
FLASHED STEAM AT BACA (VALLES CALDERA)

Material Properties					Results of Corrosion Tests ¹				
Alloy Tested	Standards Designation	Hardness Rockwell-A ^a	Tensile Strength ksi	Yield Strength ksi	Uniform Corrosion ² (mpy)	Pitting ³ (mpy)	SCC/SSC ¹⁰		
							U-bend ⁴	Bent- ⁵ Beam	Fracture ⁶ 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	95	80	0.7	-	-	-	-
1Cr-1.25Mo-.25V	ASTM-A470 C1 8	60.2	115	90	0.6	6.8	MF	MF(76) ⁷	T,I
1.5Cr-3.5Ni-.5Mo-.1V Steel	ASTM-A470 C1 6	60.2	110	95	0.4	9.1	MF	MF(72) ⁷	T
2.75Ni-.5Mo-.1V Steel	ASTM-A470 C1 4	59.5	105	85	0.7	9.1	MF	MF(80) ⁷	T
22Ni Ductile Cast Iron	-	-	-	-	0.7	-	-	-	-
12Cr Steel	Type 403	61.1	105	75	0.2	29.7	F	ND(70-100) ⁷	T,I
12Cr Steel ^a	Type 403	73.0	-	-	-	13.7	-	ND	-
12Cr Steel ^b	Type 403	-	-	-	-	-	-	ND	-
12Cr Steel ^c	Type 403	-	-	-	-	-	-	MF	T
12Cr-1Mo-.25V Steel ^d	Type 616	61.9	120	80	0.1	2	ND	ND(70-100) ⁷	-
12Cr-1Mo-1W-.25V Steel ^e	Type 616	68.1	145	115	0.2	16.0	F	ND(50-70) ⁷	T
12Cr-4Ni Steel	-	67.7	150	120	-	13.7	F	MF	I,T
M152 Steel	-	70.0	170	140	0.1	16.0	ND	ND(40-60) ⁷	-
A286 Steel	-	67.2	155	105	.04	N11	ND	ND	-
Monel	-	43.1	80	30	-	scale ⁸	-	-	-
Inconel X - 750	-	69.3	190	140	.04	2	F	ND	I
22Ni-6Pb-Brass	-	-	-	-	.6 ⁹	-	-	-	-
Ti-5Al-2.5Sn	-	67.5	120	115	.04	-	-	-	-

^aOne half of specimen flame hardened to R_A 73.0

^bBrazed at <788°C using 50Ag-20Cu-28Zn-2Ni braze alloy to attach Cobalt base erosion shield (65Co-30Cr-4.5W-1.25C).

^cBrazed at high temperature using same braze and shield alloys.

^dLow hardness.

^eHigh hardness.

Reference: TO-089

¹Specimens exposed to separated demisted steam at 171°C and 110 psig for 150 days and to air/moisture for final 10 days of 160 day period.

²Calculated from weight loss data.

³Calculated from maximum pit depth.

⁴Stress cracking of U-bends and bent-beams: key

ND - no fissures or cracks detected

MF - microscopic fissures ≤1 grain depth.

F - macroscopic fissures or fracture.

⁵T = transgranular mode

I = intergranular mode

When both modes are listed, first entry is dominant.

⁶R_A 61.5 = R_C 22

⁷Percent of yield stress applied.

⁸Covered with flaky nonadherent black scale.

⁹This is a minimum corrosion rate. Coupon covered with very adherent black scale which could not be completely removed.

¹⁰In this test it is not possible to distinguish between stress corrosion cracking and sulfide stress cracking.

would have been more severe if the cyclic stress had been applied during exposure.

Fatigue fracture initiation generally occurred at corrosion pits. The FEL ratios are plotted as a function of corrosion pit depth in Figure 4-1.

Figure 4-1. Ratios of FEL after exposure-to-FEL before exposure as a function of corrosion pit depth (TO-089).

All alloys exhibited significant reductions in the FEL with the occurrence of pitting. FEL reductions of 16 to 28 percent were caused by pitting during the first 34 days exposure. The most commonly used 12Cr (Type 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 days 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 Type 616 heat treated to "low" and "high" hardness levels were lowered approximately 50 percent. The two low tensile strength alloys, Type 403 (R_A 61) and Type 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 Type 403 is less notch sensitive in fatigue than the Type 616.

4.3 Results of Corrosion Tests at East Mesa, California KGRA

Summarized "screening" results of field corrosion tests in East Mesa fluids are given in Tables 4-9 (wellhead fluid), 4-10 (first flash liquid), 4-11 (second flash liquid), 4-12 (first flash steam), and 4-13 (second flash steam). Field tests were conducted after preliminary laboratory testing with wellhead fluid. The field tests are short duration tests and should be used cautiously, but they are useful as guidelines. Additional field tests are underway at East Mesa.

4.3.1 Description of Test Streams

Corrosion tests were conducted in five different streams from well Mesa 6-1. This well contains higher concentrations of corrosive species than later wells drilled at East Mesa and represents worst case conditions for this KGRA. Table 4-14 gives detailed analyses of Mesa 6-1 and Cerro Prieto wellhead fluids. Cerro Prieto data are included with the East Mesa because of the proximity and similarity of the two sites. This similarity should enable some corrosion data from Cerro Prieto to be extrapolated to East Mesa. The lab 6-1 data are the compositions of solutions taken at well Mesa 6-1 and used in laboratory corrosion studies.

The wellhead fluid in the in situ tests was a two-phase mixture because the geothermal fluid flashed in the bore of the well. The fluid from the wellhead then passed through a separator and produced the first flash liquid and steam streams where in situ testing was conducted. Additional in situ corrosion testing was conducted in second flash streams after passing through another separator. The compositions of the five in situ test streams are compared in Table 4-15 (NE-302).

TABLE 4-9
EAST MESA CORROSION SCREENING RESULTS FOR WELLHEAD FLUID

	Nonaerated Fluid				Aerated Fluid			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General 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	-	-	-	-	-	-
ACI Type CF-20	(A)	(N)	(N)	(N)	(A)	(N)	(X)	(N)
ACI Type CF-3M	A(A)	(N)	(X)	(N)	(A)	(N)	(X)	(N)
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 - general corrosion rate ≤ 1 mpy (≤ 25 $\mu\text{m/yr}$)
 B - general corrosion rate > 1 mpy but ≤ 10 mpy (> 25 $\mu\text{m/yr}$ but ≤ 250 $\mu\text{m/yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m/yr}$ but < 1270 $\mu\text{m/yr}$)
 D - general corrosion rate ≥ 50 mpy (> 1270 $\mu\text{m/yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 * - increased general corrosion

Data in parentheses are laboratory results.

See Tables 4-16 and 4-17 for more detailed information.

TABLE 4-10

EAST MESA CORROSION SCREENING RESULTS FOR LIQUID STREAM AFTER FIRST FLASH

	Nonaerated Fluid			
	General 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	-	-
ACI Type CF-20	-	-	-	-
ACI Type CF-3M	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 - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 R - general roughening of surface

See Table 4-18 for more complete data.

TABLE 4-11

EAST MESA CORROSION SCREENING RESULTS FOR LIQUID
STREAM AFTER SECOND FLASH

	Nonaerated Fluid			
	General 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	-	-
ACI Type CF-20	-	-	-	-
ACI Type CF-3M	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	-	-	-	-

* Specimens covered with adherent scale. Other experience justifies a C or D rating.

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m/yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m/yr}$ but ≤ 250 $\mu\text{m/yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m/yr}$ but < 1270 $\mu\text{m/yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m/yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected

See Table 4-18 for more complete data.

TABLE 4-12

EAST MESA CORROSION SCREENING RESULTS FOR STEAM FROM FIRST FLASH

	Nonaerated Steam					Aerated Steam				
	General Corrosion	Pitting	Crevice Corrosion	SCC	Erosion	General Corrosion	Pitting	Crevice Corrosion	SCC	Erosion
<u>Low Alloy Steels</u>										
Low Carbon	-	-	-	-	B	-	-	-	-	-
Carbon	B	-	-	N	-	-	-	-	-	-
AISI 4130	B	-	-	N	-	-	-	-	-	-
1Cr-1.3Mo-0.25V	B	-	-	X	B	B	-	-	X	-
1.5Cr-1Al-0.25Mo	-	X	-	-	*	-	X	-	-	-
3.5Ni-1.8Cr-0.4Mo-0.1V	A	X	-	-	B	C	X	-	I	-
ASTM A285	B	-	-	-	B	B	-	-	-	-
<u>Stainless Steels</u>										
AISI Type 304	-	-	-	-	A	-	-	-	-	-
AISI Type 316L	A	-	-	N	A	-	-	-	-	-
AISI Type 430	A	-	-	N	-	-	-	-	-	-
ACI Type CF-8	-	-	-	-	A	-	-	-	-	-
ACI Type CF-3M	A	-	-	N	A	-	-	-	-	-
E-Brite 26-1	A	-	-	N	-	-	-	-	-	-
12Cr	A	X	-	N	B	B	X	-	N	-
12Cr-1Mo-1W	A	X	-	N	A	B	X	-	X	-
12Cr-0.2Al	A	-	-	N	A	B	-	-	N	-
15Cr-1.7Mo	A	X	-	N	-	A	X	-	N	-
<u>Copper Based Alloy</u>										
Copper	-	-	-	N	-	C	-	-	X	-
<u>Aluminum Based Alloys</u>										
1100	-	-	-	-	-	B	X	-	-	-
5005	C	-	-	N	-	-	-	-	-	-
<u>Nickel Based Alloys</u>										
Inconel 625	A	-	-	N	-	-	-	-	-	-
Hastelloy S	A	-	-	N	-	-	-	-	-	-
Hastelloy C-276	A	-	-	N	-	-	-	-	-	-
<u>Titanium Based Alloy</u>										
Ti-1.5Ni	A	-	-	N	-	-	-	-	-	-
<u>Cobalt Based Alloy</u>										
Stellite #6	-	-	-	-	-	A	X	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected.
 X - indicated form of corrosion detected.
 * - specimen showed weight gain.
 I - intergranular corrosion.

See Table 4-19 for more complete data.

TABLE 4-13
EAST MESA CORROSION SCREENING RESULTS FOR
STEAM FROM SECOND FLASH

	Nonaerated Steam				
	General Corrosion	Pitting	Crevice Corrosion	SCC	Erosion
<u>Low Alloy Steels</u>					
Low Carbon	-	-	-	-	-
Carbon	B	N	N	-	-
AISI 4130	B	N	N	-	-
1Cr-1.3Mo-0.25V	-	-	-	-	-
1.5Cr-1Al-0.25Mo	-	-	-	-	-
3.5Ni-1.8Cr-0.4Mo-0.1V	-	-	-	-	-
ASTM A285	-	-	-	-	-
<u>Stainless Steels</u>					
AISI Type 304	-	-	-	-	-
AISI Type 316L	A	-	-	-	-
AISI Type 430	-	-	-	-	-
ACI Type CF-8	-	-	-	-	-
ACI Type CF-3M	A	-	-	-	-
E-Brite 26-1	A	N	N	-	-
12Cr	-	-	-	-	-
12Cr-1Mo-1W	-	-	-	-	-
12Cr-0.2Al	-	-	-	-	-
15Cr-1.7Mo	-	-	-	-	-
<u>Copper Based Alloy</u>					
Copper	-	-	-	-	-
<u>Aluminum Based Alloys</u>					
1100	-	-	-	-	-
5005	A	-	-	-	-
<u>Nickel Based Alloys</u>					
Inconel 625	A	-	-	-	-
Hastelloy S	A	-	-	-	-
Hastelloy C-276	A	-	-	-	-
<u>Titanium Based Alloy</u>					
Ti-1.5Ni	A	-	-	-	-
<u>Cobalt Based Alloy</u>					
Stellite #6	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
B - general corrosion rate > 1 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
N - indicated form of corrosion not detected.
X - indicated form of corrosion detected.

See Table 4-19 for more complete data.

TABLE 4-14
COMPARISON OF MESA 6-1 AND CERRO PRIETO
GEOHERMAL FLUIDS

	Cerro Prieto				East Mesa		
	Low TDS (Well M-8)		High TDS (Well M-11)		Well Mesa 6-1		Lab 6-1
	Flashed Fluid	Unflashed Fluid	Flashed Fluid	Unflashed Fluid	Flashed Fluid	Unflashed Fluid	Flashed Fluid
pH	¹ 8.21 (ppm)	² 5.43 (ppm)	¹ 7.90 (ppm)	² 5.34 (ppm)	¹ 7.70 (mg/l)	NR (mg/l)	¹ 7.60 (ppm)
TDS	17,068	NR	27,123	NR	32,250	18,847	
SiO ₂	974	590	1,345	610	341	300	101
Na	5,257	4,730	8,229	5,600	9,845	5,774	11,000
K	1,310	1,180	2,032	1,230	1,173	898	1,430
Ca	258	272	550	369	1,360	642	1,370
Mg	0.04	0.2	0.34	0.8	20.80	13.80	21.8
Cl ⁻	10,128	9,040	16,129	11,400	19,400	10,942	18,000
SO ₄ ⁼	10.0	9.0	12.0	27	<20.00	<10.00	16
HCO ₃ ⁻	32.49	38.0	59.11	27	45.70	223.0	NR
CO ₃ ⁼	11.38	NR	ND	NR	ND	NR	NR
CO ₂	NR	25.80	NR	1,250	ND	NR	NR
H ₂ S	NR	624	NR	310	NR	3	<1.0
NH ₄ ⁺	NR	NR	NR	NR	83.00	41.00	38.8
B	15.52	12.0	NR	13	NR	NR	22.4
Ba	5.72	NR	11.48	NR	42.00	18.00	58
Br	12.5	NR	36.5	NR	NR	NR	35
Cs	25.5	NR	40.9	NR	12.40	26.00	4.0
Li	14.5	10.9	25.2	13.7	30.00	37.00	55
Rb	8.4	NR	12.3	NR	6.00	7.20	1.7
Sr	7.3	NR	15	NR	56.00	58.00	226
Al	0.03	NR	0.03	NR	NR	NR	0.4
As	0.06	NR	1.1	NR	NR	0.009	1.0
Be	<0.03	NR	<0.03	NR	<0.004	0.007	NR
Co	<0.01	NR	<0.01	NR	NR	NR	NR
Cr	<0.05	NR	<0.05	NR	0.03	<0.02	NR
F	NR	NR	1.7	NR	1.60	1.23	1.5
Fe	NR	NR	NR	NR	0.250	3.40	0.18
I	0.45	NR	0.7	NR	NR	NR	NR
Mn	0.04	NR	NR	NR	1,260	0.95	0.9
Ni	<0.01	NR	<0.01	NR	NR	0.10	NR
Pb	NR	NR	NR	NR	0.200	0.17	0.26
Zn	NR	NR	NR	NR	<0.005	0.10	0.02

NR = Not Reported

ND = None Detected

¹pH at 25°

²calculated value

References: Cerro Prieto data - LA-312

East Mesa data - LA-312

Lab 6-1 data - CA-430

TABLE 4-15
COMPOSITION OF TEST STREAMS FROM WELL MESA 6-1
AT EAST MESA SITE

	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	¹ 13,000-5,000	2,803	323	44	300	16.3
Separator 2 Steam	5.7	¹ 200-500	10	82	<10	<10	<.1

¹Data distorted by control valve problems.

References: (NE-302, GE-119)

Test conditions and detailed results of the laboratory and field corrosion tests are described in the following sections.

4.3.2 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.

Twenty-five alloys were tested for uniform corrosion, pitting, crevice corrosion, and stress corrosion cracking (CA-340, HA-628). 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 well Mesa 6-1. The composition of this solution is given in Table 4-14.

The laboratory tests were useful for establishing guidelines and identifying potential problems, but they did not directly simulate actual site conditions for the following reasons:

1. Laboratory test temperatures (105°C) were lower than wellhead temperatures (130°C).
2. Laboratory solutions did not contain non-condensable gases.
3. The pH of the laboratory solution was less than that of the natural wellhead fluid.

Laboratory tests were run at 105°C for 15 days in aerated and deaerated media. Aeration was by constant air bubbling, and deaeration was by continuous helium purge. The noncondensable gases (CO₂, H₂S, NH₃, 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 H₂S and CO₂ were lost in the flashing and purge gas. The solution pH (6-7) was less acid than the actual wellhead brine which was about 5.7.

The results of the laboratory tests are presented in Tabel 4-16. General field corrosion results are also listed to compare with laboratory results of the same test duration, 15 days.

TABLE 4-16

RESULTS OF LABORATORY AND FIELD CORROSION TESTS IN EAST MESA WELLHEAD FLUID

Metals	Corrosion in Nonaerated Fluid					Corrosion in Aerated Fluid				Comments
	Field Test ^a (130°C) General Corrosion (mpy)	Laboratory Tests ^b (105°C)				Laboratory Tests ^c (105°C)				
		General Corrosion (mpy)	Pitting	Crevice Corrosion	SCC	General Corrosion (mpy)	Pitting	Crevice Corrosion	SCC	
Iron Base										
Carbon Steel (AISI 1020)	3.2	17.3	N	-	N	40.9	N	-	N	^a 15 day field test at Mesa 6-1 (GE-119). ^b BOM laboratory test (15 day) in Mesa 6-1 wellhead fluid without noncondensable gases - deaerated by continuous Argon purge (CA-430). ^c BOM laboratory test (15 day) in Mesa 6-1 wellhead fluid without noncondensable gases - aerated with continuous air purge (CA-430). ^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 counterparts.
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	-	-	-	-	-	-	-	-	
ACI Type CP-20	-	-	-	-	-	-	-	-	-	
ACI Type CP-3M	-	-	-	-	-	-	-	-	-	
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	
Nickel Base										
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 C	-	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	
Titanium Base										
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	
Aluminum Base										
2024-T3	-	4.9	N	-	N	45.4	1400mpy ^d	-	N	
6061-T6	-	2.1	N	-	e	2.1	N	-	e	
5005	57.0	-	-	-	-	-	-	-	-	
Copper Base										
Copper	-	1.9	N	-	N	63.1	N	-	N	
Cu-2Fe	-	3.7	N	-	N	11.6	N	-	N	
90-10 Brass	-	2.2	N	N	N	3.6	N	X ^f	N	
70-30 Brass	-	1.2	N	N	N	4.3	N	X ^f	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	
Molybdenum Base										
TZM	-	0.2	N	-	N	3.0	N	-	N	

KEY TO TABLE

N - not detected.

X - detected.

Reference for column 1 - GE-119 and NE-302)

Reference for other data: CA-430)

All of the alloys had good uniform corrosion resistance (less than 5 mpy) in the deaerated fluid except carbon steel and 70-30 cupronickel which corroded moderately. Carbon steel, AISI 4130 steel, 2024-T3 aluminum, copper, Cu-2Fe, and 70-30 cupronickel corroded severely when the fluid was aerated. Titanium and its alloys, the Hastelloys, the Inconels, Sandvik 3RE60, Type 302 stainless steel, and Type 316L stainless steel had good resistance to general corrosion, and the corrosion rates were not significantly affected by aeration (NE-302).

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 Type 316L stainless steel, but this corrosion was detected on Type 302, Type 316L, Sandvik 3RE60, Monel 400, titanium, 90-10 brass, and 70-30 brass in aerated fluid. The test conditions of pH, temperature, noncondensable 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 evidenced by the laboratory tests (NE-302).

None of the laboratory specimens showed any evidence of stress corrosion cracking, but the aluminum alloy 6061-T6 showed increased corrosion in the stressed area of the U-bends.

4.3.3 Field Tests

Ten alloys were tested in a dual flash simulation at East Mesa. Coupons were exposed to wellhead fluid from Mesa 6-1, first and second flash liquid streams, and first and second flash steams. The compositions of these streams are given in Table 4-15. U-bend stress corrosion cracking specimens were exposed to first flash steam.

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 SCC. The corrosion rates were determined by weight-loss measurements of at least four coupons (NE-302). These tests were to be included in a 60-day, planned interval test, but well Mesa 6-1 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.

In another series of tests at Mesa 6-1, the corrosion rates of five alloys were determined as a function of temperature and pH. Weight-loss measurements were made for coupons in well-head fluid at (1) normal conditions, (2) lower temperature, and (3) lower pH. Lower temperature fluids were obtained by passing fluid through cooling coils, and acid injection was used to lower pH.

The results of in-situ corrosion tests in Mesa 6-1 wellhead fluid, flashed fluids, and flashed steams are given in Tables 4-17, 4-18, and 4-19, respectively. All results are for 15 days exposure.

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-2% Ni, and 316 L showed excellent resistance to general corrosion in all five environments with corrosion rates less than 0.1 mpy. Microscopic examination of these materials, however, showed that only Hastelloy C-276 exhibited no visual evidence of corrosion. Type 316 L and Inconel 625 showed localized corrosion in

TABLE 4-17

FIELD CORROSION RESULTS IN EAST MESA WELLHEAD FLUID^a

Metal	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 316 L	<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

References: GE-119, CA-430, NE-302

TABLE 4-18

CORROSION TEST RESULTS IN FIRST AND SECOND FLASHED FLUID AT EAST MESA

	Nonaerated First Flash Fluid ¹				Nonaerated Second Flash Fluid ¹				Comments
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC	
<u>Iron Base</u>									
Carbon Steel (AISI 1020)	2.4	N	X ^b	-	3.3	N	X ^b	-	^a Microscopic pits too small to measure with optical micrometer (NE-302). ^b Some crevice corrosion (NE-302). ^c "Severe" pitting (NE-302). ^d "Very severe" crevice corrosion (NE-302). ^e Specimens covered with hard adherent scale which could not be removed (GE-119).
AISI 4130	1.6	N ^a	X ^b	-	1.2	N ^a	X ^b	-	
AISI Type 316L	<0.05	X ^a	-	-	0.1	X ^a	-	-	
AISI Type 430	0.5	X ^a	-	-	0.2	X ^a	-	-	
ACI Type CF-3M	<0.05	X ^a	-	-	0.1	X ^a	-	-	
E-Brite 26-1	<0.05	X ^a	-	-	0.1	N	-	-	^d "Very severe" crevice corrosion (NE-302).
<u>Nickel Base</u>									
Inconel 625	<0.05	-	-	-	<0.05	-	-	-	Note: Performance of cast (ACI) alloy based on wrought counterpart.
Hastelloy S	<0.05	-	-	-	<0.05	-	-	-	
Hastelloy C-276	<0.05	-	-	-	<0.05	-	-	-	
<u>Aluminum Base</u>									
5005	21.4	X ^c	X ^d	-	2.7 ^a	X ^c	X ^d	-	
<u>Titanium Base</u>									
Ti-1.5Ni	<0.05	-	-	-	<0.05	-	-	-	

¹15 day field test in first flash Mesa 6-1 fluid (pH = 6.8, Cl⁻ = 12,062 ppm).²15 day field test in second flash Mesa 6-1 fluid (pH = 8.1, Cl⁻ = 12,735 ppm).

Reference: GE-119

TABLE 4-19

CORROSION TEST RESULTS IN FIRST AND SECOND FLASHED STEAM AT EAST MESA

Alloys Tested	First Stage Steam							Second Stage Steam	Comments	
	E. Mesa Test ¹	Cerro Prieto Tests ²						E. Mesa Test ¹		
		Nonaerated				Aerated				
		General Corrosion (mpy)	General Corrosion (mpy)	Erosion (mpy)	Pitting (mpy)	SCC	General Corrosion (mpy)			Pitting (mpy)
Low Alloy Steels										
Low Carbon Steel	-	-	1.4	-	-	-	-	-	^a Some crevice corrosion.	
Carbon Steel	2.1 ^{a,b}	-	-	-	-	-	-	-	^b No stress corrosion cracking detected.	
4130	1.3 ^{a,b}	-	-	-	-	-	-	-	^c Very small shallow pits.	
1Cr-1.3Mo-0.25V	-	1.6	3.3	-	X ^f	8.3	-	X	^d No microscopic evidence of local corrosion.	
1.5Cr-1Al-0.25Mo	-	-	-	38.2	-	-	33.5	-	^e Severe pitting and local corrosion.	
3.5Ni-1.8Cr-0.4Mo-0.1V	-	0.6	1.6	4.7	-	13.4	27.6	N ^g	^f Microscopic cracks observed.	
ASTM A285	-	1.6	2.7	-	-	2.6	-	-	^g Intergranular corrosion.	
Stainless Steels										
AISI Type 304	-	-	0.1	-	-	-	-	-	^h Failure due to general corrosion.	
AISI Type 316L	<0.05 ^b	-	-	-	-	-	-	-		
AISI Type 430	<0.05 ^{a,b,c}	-	-	-	-	-	-	-		
ACI Type CP-8	-	-	0.1	-	-	-	-	-		
ACI Type CP-3M	-	-	-	-	-	-	-	-		
E-Brite 26-1	<0.05 ^{b,d}	-	-	-	-	-	-	-		
12Cr	-	0.4	1.1	0.9	N	3.9	66.9	N ^f		
12Cr-1Mo-1W	-	0.2	0.4	0.9	N	2.7	63.0	X		
12Cr-0.2Al	-	0.8	0.7	-	N	4.3	-	N		
15Cr-1.7Mo	-	0.2	0.5	5.9	N	0.5	47.3	N		
Copper Based Alloy										
Deoxidized Copper	-	-	-	-	N	20.1	-	X ^h		
Aluminum Based Alloys										
1100	-	-	-	-	-	3.3	114.2	-		
5005	29.0 ^e	-	-	-	-	-	-	-		
Nickel Based Alloys										
Inconel 625	<0.05 ^b	-	-	-	-	-	-	-		
Hastelloy S	<0.05 ^b	-	-	-	-	-	-	-		
Hastelloy C-276	<0.05 ^b	-	-	-	-	-	-	-		
Titanium Based Alloy										
Ti-1.5Ni	<0.05 ^b	-	-	-	-	-	-	-		
Cobalt Based Alloy										
Stellite #6	-	-	-	-	-	2.2	106.3	-		

¹Onsite 15 day tests at E. Mesa (GE-119 and NE-302).²Onsite 150 day tests at Cerro Prieto (GE-119 and TO-085).

KEY TO TABLE

N - no gross stress corrosion cracking failures.

X - gross stress corrosion cracking.

Note: Performance of cast (ACI) alloys is based on their wrought counterparts.

the form of very shallow pits, too small to be measured with an optical micrometer (less than 0.1 mil). A general surface roughening was noted on coupons of Ti-2Ni and Hastelloy S.

E-Brite 26-1 and Type 430 had excellent resistance to corrosion in the two separated fluid and steam environments but only fair resistance to corrosion in the wellhead fluid. Microscopic examination of all Type 430 samples showed the same shallow pitting that was observed on Type 316 L 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 to uniform corrosion in the five environments even though the microscopic examination showed general corrosion attack (NE-302).

The corrosion resistance of aluminum 5005 in each of the five environments was poor. In addition to high general corrosion rates, the aluminum samples were severely pitted and showed a high susceptibility to crevice corrosion (NE-302).

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 materials of construction. 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 general,

pitting, and crevice corrosion in these chloride environments (NE-302).

Table 4-20 presents the preliminary results of tests to determine the effects of temperature and pH on the general corrosion of East Mesa wellhead fluid. These results are for Mesa 6-1 fluid at the following conditions:

1. 150°C and pH 5.6-5.8 (normal conditions).
2. 50°C and pH 5.6-5.8
3. 150°C and pH 4.6-4.8.

The corrosion rates of AISI 1010, AISI 4130, and ASTM A53B decreased with decreasing temperature while AISI 410 and E-Brite 26-1 had low corrosion rates at both temperatures.

The acid injection data confirmed the pH dependence of carbon steel corrosion. Corrosion rates for AISI 1010, AISI 4130, and ASTM A53B increased 3 to 4 times with an acidification of one pH unit. The 410 chromium steel and E-Brite 26-1 showed no pH dependence over the range tested (SH-381).

TABLE 4-20
EFFECT OF TEMPERATURE AND ACIDIFICATION ON
GENERAL CORROSION AT EAST MESA

	Mesa 6-1 fluid* 150°C pH 5.6 - 5.8 (mpy)	Mesa 6-1 fluid* 50°C pH 5.6 - 5.8 (mpy)	Mesa 6-1 fluid* 150°C 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

*SiO₂ = 300 mg/l, Cl⁻ = 13,300 ppm, H₂S = 1.3 mg/l, O₂ <10ppb
Reference: SH-S-379

4.4 Results of Corrosion Tests at Heber, California KGRA

Limited corrosion testing has been done at the Heber KGRA. The results are summarized in Table 4-21. Their utility is somewhat limited by the fact that scale and corrosion products were not removed before weight losses were determined. As a result, corrosion rate calculations based on weight loss are suspect.

4.4.1 Test Conditions

Heat exchanger and in-situ coupon testing were conducted at the Heber, California geothermal site (SY-028).

Coupons of potential construction materials were exposed to flowing fluid from well Nowlin No. 1 for 42 days. Fluid composition is given in the second column of Table 4-22. After exposure, the coupons were examined and the weight change was determined. However, the coupons were not cleaned or descaled which makes accurate general corrosion rates difficult to obtain. No significant weight loss was found except for carbon steel. The observed weight changes and observations about localized corrosion are given in Table 4-23.

4.4.2 Results

The data in Table 4-23 indicate a uniform corrosion rate of about 2.5 mpy for carbon steel. This value compares reasonably well with the uniform corrosion rate of carbon steel at East Mesa of 3.2 mpy. Compositions of these two fluids are similar. Only Type 316L and E-Brite 26-1 showed signs of local corrosion (small pits). This pitting behavior is similar to results obtained at East Mesa (NE-302).

TABLE 4-21

HEBER CORROSION SCREENING RESULTS FOR WELLHEAD FLUID

	Nonaerated Fluid			
	<u>Uniform</u> <u>Corrosion</u>	<u>Pitting</u>	<u>Crevice</u> <u>Corrosion</u>	<u>SCC/</u> <u>SSC</u>
<u>Iron Base</u>				
Carbon Steel	B	N	-	-
AISI Type 316L	A	X	-	-
Haynes Alloy 20 Mod	A	N	-	-
Carpenter Alloy 20 Cb-3	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	-	-
Ti Code 12	A	N	-	-

Note: Specimens were not descaled before weight-loss determination.

Key to Table

A - general corrosion rate $\leq 1\text{mpy}$	($\leq 25\mu\text{m/yr}$)
B - general corrosion rate $> 1\text{mpy}$ but $\leq 10\text{mpy}$	($> 25\mu\text{m/yr}$ but $\leq 250\mu\text{m/yr}$)
C - general corrosion rate $> 10\text{mpy}$ but $< 50\text{mpy}$	($> 250\mu\text{m/yr}$ but $< 1270\mu\text{m/yr}$)
D - general corrosion rate $\geq 50\text{mpy}$	($\geq 1270\mu\text{m/yr}$)
N - indicated form of corrosion detected	
X - indicated form of corrosion not detected	

Refer to Table 4-22 for more detailed information.

TABLE 4-22
COMPOSITION OF GEOTHERMAL FLUID FROM TWO WELLS
AT HEBER, CALIFORNIA KGRA^a

Fluid Component		Concentration in Well Nowlin No. 1 (ppm)	Concentration in Well Hotz No. 2 (ppm)
Key Species:	Cl ⁻	9000	8242
	SO ₄ ⁼	100	148
	H ₂ S	2 ^b	Not reported
	HCO ₃ ⁻	20	Not reported
	CO ₃ ⁼	4	Not reported
	CO ₂	100-180 ^b	Not reported
	NH ₃	5-13 ^b	Not reported
	pH	7.1	7.4
	Other Species:		
	SiO ₂	120	187
	Na	3600	4720
	K	360	231
	Li	6.6	4.1
	Ca	880	1062
	Ba	Not reported	3.
	Mg	2.4	23
	F	1.6	1.5
	Al	0.04	12
	B	4.8	8.
	Cu	0.2	0.4
	Fe	0.9	5.
	Mn	Not reported	0.9
	Pb	0.1	0.6
	Sr	nr	42
	Zn	0.7	0.1
Total Dissolved Solids		14100	16330

^aThere are only traces of CO₂, H₂S, and other noncondensable gases in Heber fluids (LA-312).

^bReference: SY-028
Other data from LA-312

TABLE 4-23

CORROSION TEST RESULTS FOR WELLHEAD FLUID AT HEBER, CALIFORNIA

	Weight Change ^a μg/cm ² day	Pitting	Crevice Corrosion	SCC/ SSC	Comments
^a Weight loss determined without descaling of specimens					
^b Few small pits					

Coupons exposed to flowing Nowlin #1 wellhead fluid for 42 days.

Reference: SY-028

Short-term 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, but the following comment was made.

"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% copper-10% 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." (LO-208)

4.5 Results of Corrosion Tests at Raft River, Idaho KGRA

The summarized "screening" results of corrosion tests at Raft River are shown in Table 4-24. The rates of uniform, pitting and crevice corrosion have been studied in coupon exposure tests using wellhead fluid. Another series of tests investigated galvanic and crevice corrosion in potential heat exchanger materials (MI-305). The results of both test programs are described in the following sections.

4.5.1 Results of Coupon Tests

Field tests at Raft River evaluated materials for binary cycle heat exchanger, valves, pumps, and other equipment items. Coupons mounted on a test rack with TFE Teflon insulators and washers were exposed to wellhead fluid from well RRGE 1 at 133°C. Fluid composition is described in Table 4-25.

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 corrosivity of the fluid changes during the test period.

After exposure the coupons were visually inspected, cleaned, and weighed. The measured weight losses measured after 109 days of exposure were used to calculate uniform corrosion rates. Coupons were examined with a monocular metallurgical microscope in order to measure depth of pits and crevices. Pit and crevice depths were measured to the nearest $\pm 1\mu\text{m}$. Maximum pit or crevice depths were used to calculate penetration rates.

TABLE 4-24

RAFT RIVER CORROSION SCREENING RESULTS FOR WELLHEAD FLUID

Metal 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	-
ACI Type CF-8	A	X	X	-
ACI Type CF-8M	A	X	X	-
ACI Type CF-12M	A	X	X	-
ACI Type CA-15	A	X	X	-
Allegheny-Ludlum 216	A	X	X	-
Allegheny-Ludlum 6X	A	N	N	-
Allegheny-Ludlum 29-4	A	N	-	-
Allegheny-Ludlum 24-4-2	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 - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected

See Table 4-25 for more complete data.

TABLE 4-25
COMPOSITION OF WELLHEAD FLUID FROM THREE WELLS
IN THE RAFT RIVER, IDAHO KGRA

<u>Fluid Component</u>		<u>Concentration (ppm)</u>		
		<u>Well</u> <u>RRGE 1</u>	<u>Well</u> <u>RRGE 2</u>	<u>Well</u> <u>RRGE 3</u>
Key Species:	pH	7.23	7.46	6.70
	Cl ⁻	776	708	2170
	HCO ₃ ⁻	63.9	41.3	44.4
	SO ₄ ⁼	60.2	54.1	53.3
	H ₂ S	0.1	0.256	NR
	NH ₃	NR	NR	NR
Other Components:	SiO ₂	91	170	114
	Na	445	416	1185
	K	31.3	33.4	97.2
	Li	1.5	1.2	3.1
	Mg	2.4	0.6	0.6
	Ca	53.5	35.3	193
	Sr	1.6	1.0	6.7
	F	6.3	8.3	4.6
	Br	1.5	1.5	1.5
	I	0.04	0.03	NR
Total Dissolved Solids		1215	2000	NR

NR - not reported

Reference: MI-305

The planned interval test procedure showed that corrosion rates decreased with time. The maximum calculated rates are given in Table 4-26. Based on the results in Table 4-26, materials were classified in five categories, based on uniform and local corrosion resistance. Resistance to stress corrosion cracking and sulfide stress cracking was not considered. The results are shown in Table 4-27. 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 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. Some generalizations about the performance of various steels and alloys in Raft River fluids are given in the following paragraphs (MI-305).

4.5.1.1 Cast Iron, Carbon Steels and Low Alloy Steels

The low alloy steels suffered general corrosion as well as pitting and crevice attack. Plain carbon steels and gray cast iron were pitted worse than the low alloy steels.

4.5.1.2 Stainless Steels

AISI Type 410 and 440 steels showed the most catastrophic attack. The weight loss of these alloys was primarily due to severe pitting in the area of the beveled edge of the TFE washer, as well as the nonoccluded areas. 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 necessary for promotion of crevice corrosion. These alloys are

TABLE 4-26

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 ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³ (mpy)	SCC/ SSC	
Iron Base					
Gray Cast Iron (ASTM A48)	1.6	7.9	13.2	-	¹ Based on weight loss data after 109 day exposure unless otherwise indicated in comment column.
AISI 1018	1.8	43.5 ^b	33.6	-	² Penetration rate calculated from maximum pit depth (measured to $\pm 1 \mu\text{m}$).
Low Carbon Steel Plate (ASTM A515)	1.9	33.1	36.9	-	³ Penetration rate calculated from maximum crevice depth (measured to $\pm 1 \mu\text{m}$).
AISI 4140	0.83	32.9 ^c	14.7	-	
COR-TEN (ASTM A242)	1.1	7.5 ^d	13.2 ^f	-	
9 Cr Steel (ASTM A182 Gr.F9)	0.39	17.4 ^e	X ^h	-	
AISI Type 304	0.02	30.3 ^g	X ^j	-	
AISI Type 316	0.11	8.7 ⁱ	X ^k	-	
AISI Type 410	0.22	39.5 ^k	41.0 ^l	-	^a Fluid from RRGE1 at 133°C(272°F)
AISI Type 440A	0.28	76.5 ^m	100	-	^b General broad shallow pitting under scale.
ACI Type CF-8	0.02	30.3	X	-	^c Numerous pits of varying depth and breadth.
ACI Type CF-8M	0.11	8.7	X	-	^d Numerous small pits.
ACI Type CM-12M	0.11	8.7	X	-	^e Deep pits.
ACI Type CA-15	0.22	39.5	41.0	-	^f "Deep" crevice corrosion- no numerical data given.
Allegheny-Ludlum 216	0.038	47.9	X ⁿ	-	^g Numerous pits.
Allegheny-Ludlum 6X	0.0035	N	N	-	^h Crevice corrosion observed but not quantified.
Allegheny-Ludlum 29-4	0.0037	N	X ^o	-	ⁱ Significantly less pitting than AISI Type 304.
Allegheny-Ludlum 29-4-2	0.0035	N	N	-	^j "Some" crevice corrosion - not quantified.
Nickel Base					
Monel 400	79.7 ^p	-	-	-	^k Numerous narrow deep pits.
Inconel 625	N ^q	N	N	-	^l Severe crevice corrosion.
Hastelloy G	0.0035	X ^r	N	-	^m Scattered deep pits extending in direction of machining marks.
Titanium Base					
Titanium (ASTM B265 Gr.2)	0.0063	N	N	-	ⁿ Pit under edge of washer could be crevice corrosion.
Aluminum Base					
1100	s	X	X	-	^o Minor evidence of crevice corrosion at 109 days.
5052	s	X	X	-	^p Exposure was for 2 weeks (preliminary test).
6061	s	X	N	-	^q No evidence of corrosion was found.
Copper Base					
Ampco 8 (7Al bronze)	3.9	N	N ^t	-	^r Few small scattered pits - no depth given.
Ampco 12 (9Al bronze)	7.5	7.5	7.9 ^t	-	^s Exposure for 11 weeks all alloys were severely corroded. Some coupons showed 25% weight loss.
Ampco 483 (9Al-4.5Ni bronze)	9.8	122	9.3 ^t	-	^t Severe erosion.
Muntz Metal (61 Cu - 39 Zn)	20 ^p	X ^u	X ^v	-	^u Dealloying under washer.
90-10 Cupronickel	275 ^p	N	X ^v	-	^v Small pits with dealloying into pits.
70-30 Cupronickel	164 ^p	N	X ^v	-	^v "Grooving" around washer.
Cobalt Base					
Haynes 6B	0.017	N	N	-	

KEY TO TABLE

N - indicated form of corrosion not detected.

X - indicated form of corrosion observed but not quantified.

TABLE 4-27

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
Inconel 625		1100 Aluminum ^b
Haynes Alloy 6B	<u>Class 4</u>	5052 Aluminum ^b
Titanium (ASTM B 265 Gr 12)	<u>Marginal Resistance</u>	6061 Aluminum ^b
	Gray cast iron	
<u>Class 2</u>	AISI 1018	
<u>Acceptable Resistance</u>	Low carbon steel plate	
Allegheny-Ludlum 216	AISI 4130	
Allegheny-Ludlum 6X	COR-TEN	
Hastelloy G	9Cr-steel	
Ampco 8 (7Al bronze)	AISI Type 304	
Muntz Metal*	Ampco 483 (9Al-4.5Ni-bronze)	
	90-10 cupronickel*	
	70-30 cupronickel*	
	Monel 400*	

^a Coupons 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 (See Table 4-25).

^b Aluminum coupons were exposed for 11 weeks, after which all showed severe corrosion and erosion.

martensitic and other high chromium martensitic stainless steels have shown great susceptibility to sulfide stress cracking.

Two austenitic stainless steels were tested. The pitting and crevice corrosion of AISI Type 304 were similar to the attack on AISI Types 410 and 440, though the pits were not as numerous or deep. Though localized attack was severe, this material may be usable in some applications. AISI Type 316 was also pitted, but to a much lesser extent than Type 304. On the basis of these data, Type 316 would be acceptable in many applications. Both of these alloys are susceptible to stress corrosion cracking in dilute chloride solutions.

Precipitation-hardening stainless steels such as 17-4PH are 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 most environments. Because the 17-4PH material is used in valve stem applications, its use in the Raft River geothermal fluid should be preceded by careful testing and evaluation.

The super stainless steels, Allegheny-Ludlum Alloys 216 (20Cr-24Ni-2.5Mo), 6X (20Cr-24Ni-6Mo), 29-4 (29Cr-4Mo), and 29-4-2 (29Cr-4Mo-2Ni) were resistant to general and local corrosion. The alloy 216 did show some pitting near the TFE washer.

The stress corrosion cracking resistance of these alloys is high. Nickel-free 29-4 is more resistant, though all will resist cracking in boiling 20% NaCl (GE-119).

4.5.1.3 Nickel-Based Alloys

Inconel 625 was very resistant. No general or local corrosion was detected after 109 days exposure. Hastelloy G was also resistant to general corrosion, but a few small pits were observed. Monel 400 is a nickel-copper alloy, and like all the nickel-bearing copper alloys in this study, it was severely attacked.

4.5.1.4 Copper-Based Alloys

The nickel-free copper alloys, Ampco 8 (7Al-bronze), Ampco 12 (9Al-bronze) and Muntz Metal, were all fairly resistant. Ampco 8 performed best. The nickel bearing alloys, Ampco 483 (9Al-4.5Ni-bronze), 90-10 cupronickel and 70-30 cupronickel, all suffered severe general or local attack. De-alloying occurred in some of these materials.

4.5.1.5 Titanium-Based Alloys

The titanium alloy (ASTM B 265 Gr2) was resistant to general corrosion. No local attack was observed.

4.5.1.6 Cobalt-Based Alloys

The Haynes 6B alloy was resistant to general corrosion. No local attack was observed.

4.5.1.7 Aluminum-Based Alloys

Three aluminum alloys, 1100, 5052, and 6061, were exposed in eleven-week trials. General and local corrosion were severe. Weight losses of more than 25 percent were observed after eleven weeks exposure.

4.5.2 Results of 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 4-28 shows the tube and tube sheet combinations tested.

TABLE 4-28
TUBE TO TUBESHEET COMBINATIONS TESTED AT RAFT RIVER

Tube Material	Tubesheet Material	
	Low-Carbon Steel	Naval Brass
Low-Carbon Steel	Yes	No
304 SS	Yes	No
316 SS	Yes	No
Allegheny-Ludlum 6X	Yes	No
Admiralty Brass (As)	No	Yes
70Cu/30Ni	Yes	Yes
Hastelloy G	Yes	No

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. Some pitting was identified in the 70Cu/30Ni tubing but this material is no longer considered a viable candidate for the boiler/preheater system due to excessive corrosion induced by hydrogen sulfide in the geothermal fluid (MI-305).

4.6 Results of Corrosion Tests in Salton Sea, California, KGRA

The geothermal resource at Salton Sea, California has been the subject of extensive laboratory and field testing. The results are summarized in "screening" format in Tables 4-29 through 4-36. Laboratory results are given in parentheses.

The following sections provide details about the test conditions and give numerical values for corrosion rates. Generalizations about performance and applicability of various steels and alloys are presented. Laboratory results are presented in Section 4.5.1. Results of field tests follow in Section 4.5.2.

4.6.1 Results of Laboratory Tests Using Synthetic Fluids

Two types of laboratory tests using synthetic fluids have been conducted (NE-302). One series of tests was done in a high pressure autoclave at 232°C. The second series was done at atmospheric pressure at 105°C. Both series of tests used a solution made in the laboratory by dissolving metal chlorides, silicates, and metaborates in water and adjusting the pH with sodium hydroxide. The composition is defined in Table 4-37. The composition of the test solution is based on that of flashed fluid from well IID 2.

4.6.1.1 Results of Autoclave Tests at 232°C

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 1300 ml of unstirred synthetic fluid contained in a two-liter, high pressure glasslined stainless steel

Table 4-29

**SALTON SEA CORROSION SCREENING RESULTS FOR
WELLHEAD FLUID**

	Nonaerated Fluid				Aerated Fluid			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
Iron Base								
Carbon Steel (AISI 1020)	D(B)	X(X)	N(X)	N(N)	(D)	(X)	(N)	(-)
AISI 4130	C(B)	X(N)	N(X)	N(N)	(-)	(-)	(-)	(-)
COR-TEN B	(B)	(X)	(X)	(-)	(D)	(N)	(-)	(-)
Mariner	(B)	(N)	(X)	(-)	(D)	(N)	(-)	(-)
AISI Type 316L	A(A)	X(N)	X(X)	I, X(X)	(D)	(X)	(X)	(X)
AISI Type 430	A-B(A)	X(N)	N(N)	N(X)	(D)	(X)	(-)	(X)
ACI Type CF-3M	A(A)	X(N)	X(X)	I, X(X)	(D)	(X)	(X)	(X)
Sandvik 3RE60	(B)	(N)	(X)	(X)	(-)	(-)	(X)	(D)
Carpenter 20	(A)	(N)	(X)	(X)	(-)	(-)	(-)	(-)
Allegheny-Ludlum 6X	A(-)	N(-)	N(-)	N(-)	(-)	(-)	(-)	(-)
Allegheny-Ludlum 29-4	A(-)	N(-)	N(-)	N(-)	(-)	(-)	(-)	(-)
E-Brite 26-1	A(A)	X(N)	N(N)	N(N)	(C)	(C)	(X)	(N)
Nickel Base								
Monel 400	(B)	(X)	(N)	(N)	(D)	(X)	(-)	(-)
Inconel X-750	(A)	(N)	(X)	(N)	(-)	(-)	(-)	(-)
Inconel 625	A(A)	N(N)	N(N)	N(N)	(C)	(X)	(X)	(X)
Hastelloy S	A(A)	N(N)	N(X)	N(N)	(-)	(-)	(-)	(-)
Hastelloy G	A(A)	N(X)	N(X)	N(N)	(-)	(-)	(-)	(-)
Hastelloy C-276	A(A)	N(N)	N(N)	N(N)	(B)	(X)	(X)	(X)
Copper Base								
70-30 Cupronickel	(B)	(N)	(N)	(N)	(D)	(X)	(X)	
Titanium Base								
Titanium	(A)	(X)	(X)	(N)	(A)	(N)	(N)	(X)
Ti-1.7W	(A)	(N)	(N)	(N)	(-)	(-)	(-)	(-)
Ti-1.5Ni	A(A)	N(N)	N(X)	N(N)	(A)	(-)	(N)	(X)
Ti-10V	A(N)	(N)	(N)	(N)	(-)	(-)	(-)	(-)
Ti-0.2Pd	(A)	(N)	(N)	(N)	(-)	(-)	(-)	(-)
TiCode-12	A(A)	N(N)	N(N)	N(N)	(A)	(N)	(-)	(-)
Molybdenum Base								
TZM	(A)	(N)	(N)	(N)	(-)	(-)	(-)	(-)

		Corrosion Rate (mpy)			
		Deaerated		100 ppm O ₂	
Material	Weld Technique	Weld	Non Weld	Weld	Non Weld
Carbon Steel (AISI 1020)	Stick ¹	C	B	D	D
AISI 4130	Stick	C	B	D	D
AISI	Tig ²	A*	A	D*	D
E-Brite 26-1	Tig	A	A	A	C
Inconel 625	Tig	A	A	A	A
Titanium	Tig	A	A	A	A
Ti-0.2Pd	Tig	A	A	D	C

¹Stick - Shielded metal-arc welding.²Tig - Inert gas tungsten-arc welding.

See Table for more detailed data.

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m/yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m/yr}$ but ≤ 250 $\mu\text{m/yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m/yr}$ but < 1270 $\mu\text{m/yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m/yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion
 * - SCC detected

Data in parentheses are from laboratory studies.

TABLE 4-30

SALTON SEA CORROSION SCREENING RESULTS FOR FLUID (LIQUID STREAM)AFTER FIRST FLASH

	<u>Nonaerated Fluid</u>				<u>Aerated Fluid</u>			
	<u>General Corrosion</u>	<u>Pitting</u>	<u>Crevice Corrosion</u>	<u>SCC</u>	<u>General Corrosion</u>	<u>Pitting</u>	<u>Crevice Corrosion</u>	<u>SCC</u>
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	C-D	X	N	N	-	-	-	-
AISI 4130	B	X	N	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	X	I,X	-	-	-	-
AISI Type 430	A	X	X	-	-	-	-	-
ACI Type CF-3M	A	X	X	I,X	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	N	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-45 for more detailed data.

TABLE 4-31

SALTON SEA CORROSION SCREENING RESULTS FOR STEAM FROM FIRST FLASH

	Nonaerated Steam				Aerated Steam			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	C	X	N	N	-	-	-	-
AISI 4130	B	X	N	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	N	I,X	-	-	-	-
AISI Type 430	A	X	X	-	-	-	-	-
ACI Type CF-3M	A	X	N	I,X	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	X	N	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-46 for more exact data.

TABLE 4-32

SALTON SEA CORROSION SCREENING RESULTS FOR SCRUBBED STEAM FROM FIRST FLASH

	Nonaerated Steam				Aerated Steam			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	C	X	X	N	-	-	-	-
AISI 4130	C	X	N	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	X	N,I	-	-	-	-
AISI Type 430	A	X	N	N	-	-	-	-
ACI Type CF-3M	A	X	X	N,I	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	X	N	N	-	-	-	-
Allegheny-Ludlum 216	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	N	N	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m/yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m/yr}$ but ≤ 250 $\mu\text{m/yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m/yr}$ but < 1270 $\mu\text{m/yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m/yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-47 for more data.

TABLE 4-33

SALTON SEA CORROSION SCREENING RESULTS FOR FLUID (LIQUID STREAM)AFTER SECOND FLASH

	<u>Nonaerated Fluid</u>				<u>Aerated Fluid</u>			
	<u>General Corrosion</u>	<u>Pitting</u>	<u>Crevice Corrosion</u>	<u>SCC</u>	<u>General Corrosion</u>	<u>Pitting</u>	<u>Crevice Corrosion</u>	<u>SCC</u>
<u>Iron Base</u>								
Carbon Steel	C	X	N	N	-	-	-	-
AISI 4130	B-C	X	N	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	X	N, I	-	-	-	-
AISI Type 430	A	X	X	N	-	-	-	-
ACI Type CF-3M	A	X	X	N, I	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	X	N	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
<u>Monel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.1W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate <1.0 mpy (<25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate >1.0 mpy but <10 mpy (>25 $\mu\text{m}/\text{yr}$ but <250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate >10 mpy but <50 mpy (>250 $\mu\text{m}/\text{yr}$ but <1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate $\geq$ 50 mpy ($\geq$ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-48 for more detailed data.

TABLE 4-34

SALTON SEA CORROSION SCREENING RESULTS FOR STEAM FROM SECOND FLASH

	Nonaerated Steam				Aerated Steam			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	C	X	N	N	-	-	-	-
AISI 4130	B	X	N	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	X	I,X	-	-	-	-
AISI Type 430	A	X	X	-	-	-	-	-
ACI Type CF-3M	A	X	X	I,X	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	X	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	N	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TiZr	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate <1.0 mpy (<25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate ≥ 1.0 mpy but <10 mpy (≥ 25 $\mu\text{m}/\text{yr}$ but <250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate >10 mpy but <50 mpy (>250 $\mu\text{m}/\text{yr}$ but <1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-49 for more detailed data.

TABLE 4-35

SALTON SEA CORROSION SCREENING RESULTS FOR SCRUBBED STEAM FROM SECOND FLASH

	Nonaerated Fluid				Aerated Fluid			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
<u>Iron Base</u>								
Carbon Steel (AISI 1020)	C	X	X	N	-	-	-	-
AISI 4130	C	X	X	N	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	X	X	N,I	-	-	-	-
AISI Type 430	B	X	X	N	-	-	-	-
ACI Type CF-3M	A	X	X	N,I	-	-	-	-
Sandvik 3RE60	-	-	-	-	-	-	-	-
Carpenter 20	-	-	-	-	-	-	-	-
Allegheny-Ludlum 6X	A	X	X	N	-	-	-	-
Allegheny-Ludlum 29-4	A	N	N	N	-	-	-	-
E-Brite 26-1	A	X	X	N	-	-	-	-
<u>Nickel Base</u>								
Monel 400	-	-	-	-	-	-	-	-
Inconel X-750	-	-	-	-	-	-	-	-
Inconel 625	A	N	N	N	-	-	-	-
Hastelloy S	A	N	X	N	-	-	-	-
Hastelloy G	A	N	N	N	-	-	-	-
Hastelloy C-276	A	N	N	N	-	-	-	-
<u>Copper Base</u>								
70-30 Cupronickel	-	-	-	-	-	-	-	-
<u>Titanium Base</u>								
Titanium	-	-	-	-	-	-	-	-
Ti-1.7W	-	-	-	-	-	-	-	-
Ti-1.5Ni	A	N	N	N	-	-	-	-
Ti-10V	-	-	-	-	-	-	-	-
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	A	N	N	N	-	-	-	-
<u>Molybdenum Base</u>								
TZM	-	-	-	-	-	-	-	-

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m}/\text{yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m}/\text{yr}$ but ≤ 250 $\mu\text{m}/\text{yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m}/\text{yr}$ but < 1270 $\mu\text{m}/\text{yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m}/\text{yr}$)
 N - indicated form of corrosion not detected
 X - indicated form of corrosion detected
 I - intergranular corrosion

Refer to Table 4-50 for more detailed data.

TABLE 4-36

SALTON SEA CORROSION SCREENING RESULTS FOR CONCENTRATED GAS-FREE FLUID AT 105°C

	Nonaerated Fluid				Aerated Fluid			
	General Corrosion	Pitting	Crevice Corrosion	SCC	General Corrosion	Pitting	Crevice Corrosion	SCC
Iron Base								
Carbon Steel (AISI 1020)	B	N	-	-	B	N	-	-
AISI 4130	-	-	-	-	-	-	-	-
COR-TEN B	-	-	-	-	-	-	-	-
Mariner	-	-	-	-	-	-	-	-
AISI Type 316L	A	N	X	N	B	N	X	-
AISI Type 430	-	-	-	-	-	-	-	-
ACI Type CF-3M	A	N	X	N	B	N	X	-
Sandvik 3RE60	A	N	X	N	A	N	X	N
Carpenter 20	A	N	X	N	B	N	X	N
Allegheny-Ludlum 6X	-	-	-	-	-	-	-	-
Allegheny-Ludlum 29-4	-	-	-	-	-	-	-	-
E-Brite 26-1	A	N	N	N	B	N	N	N
Nickel Base								
Monel 400	B	N	X	N	B	N	X	N
Inconel X-750	A	N	X	N	B	N	X	N
Inconel 625	A	N	N	N	A	N	N	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
Copper Base								
Copper	B	N	N	N	C	N	N	N
Cu-2Fe	B	N	-	-	C	N	-	-
70-30 Cupronickel	A	N	X	N	B	N	X	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	N	N	N	A	N	N	N
Ti-10V	A	N	N	N	A	N	N	N
Ti-0.2Pd	-	-	-	-	-	-	-	-
TiCode-12	-	-	-	-	-	-	-	-
Aluminum Base								
2024-T3	B	X	X	*	C	N	X	*
6061-T6	C	X	N	*	D	N	N	*
Molybdenum Base								
TZM	A	N	N	N	B	N	X	N

KEY TO TABLE

- A - general corrosion rate ≤ 1.0 mpy (≤ 25 $\mu\text{m/yr}$)
 B - general corrosion rate > 1.0 mpy but ≤ 10 mpy (> 25 $\mu\text{m/yr}$ but ≤ 250 $\mu\text{m/yr}$)
 C - general corrosion rate > 10 mpy but < 50 mpy (> 250 $\mu\text{m/yr}$ but < 1270 $\mu\text{m/yr}$)
 D - general corrosion rate ≥ 50 mpy (≥ 1270 $\mu\text{m/yr}$)
 N - indicated form of corrosion not detected.
 X - indicated form of corrosion detected.
 I - intergranular corrosion.
 * - much increased general corrosion in stressed area.

Refer to Table 4-41 for more detailed data.

TABLE 4-37. COMPOSITION OF SYNTHETIC SALTON SEA
FLUID USED IN LABORATORY TESTS (NE-302)

Constituent	Concentration (ppm) ^a		
	Nominal ^b	As Prepared ^c	After 15 days at 232°C
Na	53,000	59,250	68,250
Ca	28,000	22,400	19,350
K	16,500	16,700	13,150
Fe	2,000	3.9	3.6
Mn	1,370	1,710	1,650
Zn	500	345	542
Sr	440	706	313
SiO ₂	400	21	47
B	390	200	-1
Ba	250	294	344
Li	210	182	178
Pb	80	14	69
Rb	70	74	89
Cs	20	-	-
Mg	10	27	4
Ge	-	-	-
As	-	-	-
Al	-	-	-
Cl	155,000	140,200	148,200
Sulfide	30	34	<.1

^adash means not measured

^bbased on the composition of unflashed fluid from well 11D
No. 2, pH = 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 = 5.0.

Reference: NE-302

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.

Tests specimens were immersed in the test solution, the solution was vacuum degassed, and the autoclave was sealed and heated to $232 \pm 2^\circ\text{C}$. 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, CO_2 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 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, with 100 ppm O_2 in the liquid, 250 ppm CO_2 , and 100 ppm CH_4 .

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 de-aerated and oxygenated fluid at 232°C . Weight-loss samples were butt-welded together following practices recommended by the American Society for Metals. These samples were not heat treated to relieve stresses prior to corrosion testing.

The numerical corrosion rates measured in autoclave tests are summarized in Tables 4-38, 4-39, and 4-40. Table 4-38 shows results of tests of coupons, crevice specimens, and U-bend specimens in deaerated fluid and tests in which oxygen was added

TABLE 4-38

CORROSION RATES MEASURED IN FIFTEEN-DAY AUTOCLAVE TESTS USING DEAERATED AND
OXYGENATED SYNTHETIC SALTON SEA FLUID

	Deaerated Solution				Solution Containing 100 ppm O ₂				Comments
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	
<u>Iron Base</u>									
Carbon Steel (AISI 1020)	4.8	50	X ^d	2.2 N	1060	X ^a	N	-	¹ Based on weight loss.
AISI 4130	3.8	N	X ^d	10.3 N	-	-	-	-	² Based on maximum pit depth.
COR-TEN B	1.3	X ^a	X ^d	-	1180	N	-	-	³ Specimens with fabricated crevices.
Mariner	1.6	N	X ^d	-	1310	N	-	-	⁴ U-bend specimens (numerical data
AISI Type 316L	<0.05	N	X ^b	0.2 X	245	X ^a	X ^d	81 X	are general corrosion rates of
AISI Type 430	<0.05	N	N	<0.05 X	345	X ^a	-	345 X	U-bend specimens.
Sandvik 3RE60	2.0	N	X ^c	1.0 X	-	-	X ^c	-	
E-Brite 26-1	0.1	N	N	0.1 N	20.7	36.5	X ^d	39.3 X	^a "Light pitting" (NE-302).
Carpenter 20	0.3	N	X ^c	0.3 X	-	-	-	-	^b <1 mpy.
<u>Nickel Base</u>									
Monel 400	1.7	X ^a	N	12.0 N	288	X ^a	-	-	^c >1 mpy but <5 mpy.
Inconel X-750	0.3	N	X ^c	0.4 N	-	-	-	-	^d >5 mpy.
Inconel 625	<0.05	N	N	<0.05 N	19.2	530	X ^d	22.4 X	
Hastelloy S	<0.05	N	X ^b	<0.05 N	-	-	-	-	
Hastelloy G	0.1	X	X	0.4 N	-	-	-	-	
Hastelloy C-276	0.05	N	N	0.1 N	6.0	125	X ^d	11.3 X	
<u>Copper Base</u>									
70-30 Cupronickel	3.2	N	N	7.8 N	225	X ^a	X ^d	-	
<u>Titanium Base</u>									
Titanium	0.3	100	X ^d	0.5 N	<0.05	N	N	0.1 N	
Ti-1.7W	<0.05	N	N	<0.05 N	-	-	-	-	
Ti-1.5W1	0.1	N	X ^c	0.2 N	<0.05	-	N	<0.05 N	
Ti-10V	<0.05	N	N	<0.05 N	-	-	-	-	
Ti-0.2Pd	0.05	N	N	<0.05 N	<0.05	N	N	0.1 X	
TiCode-12	-	-	-	-	<0.05	N	N	-	
<u>Molybdenum Base</u>									
TZM	0.6	N	N	0.8 N	-	-	-	-	

T = 232°C (450°F) pres = 422.6 psia* Cl⁻ = 155,000 ppm.
* - steam table value.

Reference: NE-302

TABLE 4-39

**CORROSION RATES MEASURED IN FIFTEEN-DAY AUTOCLAVE TESTS USING SYNTHETIC
SALTON SEA FLUID WITH ADDITION OF CO₂ AND CH₄**

	Solution Containing 250 ppm CO ₂				Solution Containing 100 ppm CH ₄				Comments
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	
Iron Base									
Carbon Steel (AISI 1020)	-	-	-	-	2.4	N	-	2.1 N	¹ Based on weight loss.
AISI 4130	-	-	-	-	3.3	X ^a	X ^b	-	² Based on maximum pit depth.
COR-TEN B	1.8	X ^a	-	-	0.4	N	-	-	³ Specimens with fabricated crevices.
Mariner	8.4	X ^a	-	-	1.5	N	-	-	⁴ U-bend specimens (numerical data are
AISI Type 316L	0.2	N	N	<0.05 X	<0.05	N	N	<0.05 X	general corrosion rates of U-bend
AISI Type 430	-	X ^a	-	0.3 X	<0.05	55	N	<0.05 X	U-bend specimens.
Sandvik 3RE60	-	-	-	-	-	-	-	-	
E-Brite 26-1	0.2	X ^a	N	<0.05 N	<0.05	30	N	<0.05 N	^a "Light pitting" (NE-302).
Carpenter 20	-	-	-	-	-	-	-	-	^b <1 mpy.
									^c <1 mpy but >5 mpy.
									^d >5 mpy.
Nickel Base									
Monel 400	0.1	X ^a	N	-	<0.05	N	N	3.4 N	
Inconel X-750	-	-	-	-	-	-	-	-	
Inconel 625	0.1	N	N	<0.05 N	0.1	N	X ^b	<0.05 N	
Hastelloy S	-	-	-	-	-	-	-	-	
Hastelloy C	-	-	-	-	-	-	-	-	
Hastelloy C-276	-	N	-	<0.05 N	<0.05	N	X ^b	<0.05 N	
Copper Base									
70-30 Cupronickel	1.0	N	N	-	3.0	N	N	-	
Titanium Base									
Titanium	<0.05	N	N	0.5 N	<0.05	N	N	<0.05 N	
Ti-1.7W	-	-	-	-	-	-	-	-	
Ti-1.5W1	-	-	-	-	-	-	-	-	
Ti-10V	-	-	-	-	-	-	-	-	
Ti-0.2Pd	0.05	N	N	0.05 N	0.05	N	N	0.05 N	
TiCode-12	-	-	-	-	0.05	N	N	0.05 N	
Molybdenum Base									
TZM	-	-	-	-	-	-	-	-	

T = 232°C (450°F) pres = 422.6 psia* Cl⁻ = 155,000 ppm.
* - steam table value.

Reference: NE-302

TABLE 4-40

RESULTS OF LABORATORY TESTS OF THE EFFECT OF WELDING
ON UNIFORM CORROSION RATE IN SYNTHETIC SALTON SEA FLUID^a

<u>Material Tested</u>	<u>Welding Technique^b</u>	<u>Uniform Corrosion Rate in Deaerated Solution (mpy)</u>		<u>Uniform Corrosion Rate in Solution Containing 100 ppm Oxygen (mpy)</u>	
		<u>Butt Welded Samples</u>	<u>Non-Welded Samples</u>	<u>Welded Samples</u>	<u>Non-Welded Samples</u>
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

^a Tests were done in a high-pressure autoclave at 232°C using synthetic fluid of the composition in Table 4-37 (NE-302).

^b Stick - shielded metal-arc welding

Tig - inert gas tungsten-arc welding

^c Stress corrosion cracking was observed.

Reference: NE-302

to the autoclave. Table 4-39 shows results obtained when CO₂ and CH₄ were added. Results of tests of welded and non-welded specimens are given in Table 4-40. Results are shown for both deaerated fluid and oxygen addition. The following paragraphs summarize the findings for carbon steels, stainless steels, and nickel, titanium, copper, and molybdenum alloys.

In deaerated fluid, the uniform corrosion rates of carbon and low alloy steels were less than 5 mpy. Carbon steel (AISI 1020) developed deep pits while the other alloys were resistant or suffered only slight attack. The crevice corrosion rates were severe. Only AISI 1020 and 4130 were tested for stress corrosion cracking. Both were resistant, but the weight loss of the AISI 4130 U-bend specimen was three times the weight loss of the AISI 4130 coupon. 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 general corrosion of low alloy steels ~1000-fold. There were no differences in weight loss for the welded and non-welded samples of 1020 and 4130 steel in tests when oxygen was added.

Stainless Steels

In non-aerated fluid stainless steels had general 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 stress corrosion cracking. Welding caused a slight increase in weight loss, and stress corrosion cracking was noted in welded specimens of the 316 L.

Addition of oxygen caused severe increases in general corrosion, pitting and crevice attack. Intergranular corrosion

of Type 316 L 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 seven-fold increase in weight loss.

Addition of CO_2 caused slight increases in severity of general corrosion and pitting but did not effect the rate of local corrosion.

Addition of CH_4 caused a severe increase in pitting and slight reductions in general corrosion.

Nickel Based Alloys

In non-aerated fluid, the general corrosion rates of the nickel alloys were less than 2 mpy. Pitting was light or did not occur. Inconel 625, Hastelloy S and Hastelloy G had significant crevice corrosion. None of the alloys displayed stress corrosion cracking, but the weight loss of Monel-400 U-bend specimens was seven times that of Monel coupons.

Aeration caused a very severe increase in uniform corrosion rate of Monel 400. The uniform corrosion rates of the other alloys also increased. Pitting and crevice corrosion of Inconel 625 and Hastelloy C-276 were severe and both alloys failed due to stress corrosion cracking. Welding caused a slight increase in weight loss of Inconel 625, the only nickel alloy tested in non-aerated fluid.

Addition of oxygen appreciably increased the general corrosion of nickel alloys and caused severe pitting and crevice corrosion of Inconel 625 and Hastelloy C-276. Stress corrosion cracking was observed in U-bend specimens of Hastelloy C-276 and Inconel 625. The weight loss of welded specimens of Inconel 625 was four times that of unwelded specimens in tests done with oxygen.

The addition of CO_2 had little effect while CH_4 caused increased crevice corrosion of Inconel 625 and Hastelloy C-276.

Titanium Based Alloys

In nonaerated fluid, all the titanium alloys had general corrosion rates of less than 0.5 mpy. Severe pitting and crevice corrosion of (commercially pure) titanium occurred. 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 stress corrosion cracking was observed and welding of Ti-0.2Pd had little effect on weight loss.

The performance of titanium alloys improved in tests when oxygen was added. All uniform corrosion rates were less than 0.05 mpy and no local corrosion or stress cracking was observed. Welding had little effect on weight loss of Ti-0.2Pd. Additions of CO_2 and CH_4 produced results similar to the addition of oxygen.

Copper Based Alloy

This alloy (70-30 cupronickel) was fairly resistant to all modes of corrosion in non-aerated fluid and fluids containing CH_4 and CO_2 . Addition of O_2 caused a severe increase in the rate of uniform corrosion as well as pitting and crevice corrosion. Addition of H_2S to any of these environments would probably cause severe corrosion.

Molybdenum Alloy

TZM was tested only in nonaerated fluid. It was very resistant to all modes of corrosion.

4.6.1.2 Laboratory Tests at 105°C

Another series of tests using the synthetic Salton Sea fluid described in Table 4-37 was done at atmospheric pressure at the boiling point of the fluid (105°C). Tests were done in a 1-liter erlenmeyer flash 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 constant 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. Corrosion rates calculated from 15-day weight loss and maximum pit or crevice depth are given in Table 4-41. The following observations about the performance of ferrous, nickel, copper, titanium, aluminum and molybdenum alloys are based on the corrosion rates summarized in Table 4-41.

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. Type 316 L, Sandvik 3 RE60, and Carpenter 20 showed slight (<0.1 mpy) crevice attack in nonaerated fluid. Crevice corrosion

TABLE 4-41

**CORROSION RATES MEASURED IN FIFTEEN-DAY LABORATORY TESTS AT 105°C USING DEAERATED
AND AERATED SYNTHETIC SALTON SEA FLUIDS**

TABLE 5-33

SITE: Salton Sea, California

ENVIRONMENT: Gas-Free Wellhead Fluid

	Deaerated Fluid				Aerated Fluid				Comments
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion	SCC ³	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion	SCC ³	
Iron Base									
Carbon Steel (AISI 1020)	4.2	N	-	N	5.8	N	-	N	¹ Based on weight loss after 15 days. ² Based on maximum pit depth. ³ U-bend specimens. ^a <0.1 mpy ^b >0.1 mpy but <1 mpy ^c >1 mpy but <5 mpy ^d >5 mpy but <50 mpy ^e >50 mpy ^f Ten-fold increase in general corrosion, concentrated in bend area. Performance of cast (ACI) alloy based on wrought equivalent. Composition of the fluid is given in Table 4-
AISI Type 316L	<0.05	N	X ^a	N	4.0	N	X ^e	N	
ACI Type CF-3M	<0.05	N	X ^a	N	4.0	N	X ^e	N	
Sandvik 3RE60	<0.05	N	X ^a	N	0.9	N	X ^e	N	
Carpenter 20	<0.05	N	X ^a	N	2.2	N	X ^d	N	
E-Brite 26-1	<0.05	N	N	N	3.6	N	N	N	
Nickel Base									
Monel 400	2.8	N	X ^c	N	3.7	N	X ^d	N	^f Ten-fold increase in general corrosion, concentrated in bend area. Performance of cast (ACI) alloy based on wrought equivalent. Composition of the fluid is given in Table 4-
Inconel X-750	<0.05	N	X ^b	N	3.4	N	X ^d	N	
Inconel 625	<0.05	N	N	N	<0.05	N	N	N	
Hastelloy S	<0.05	N	N	N	<0.05	N	X ^c	N	
Hastelloy G	<0.05	N	N	N	0.1	N	X ^c	N	
Hastelloy C-276	<0.05	N	N	N	<0.05	N	N	N	
Copper Base									
Copper	3.1	N	N	N	12.5	N	N	N	
Cu-2Fe	2.7	N	- ^b	N	13.3	N	-	N	
70-30 Cupronickel	0.6	N	X ^b	N	5.8	N	X ^c	N	
Titanium Base									
Titanium	<0.05	N	N	N	<0.05	N	X ^a	N	
Ti-1.7W	<0.05	N	N	N	<0.05	N	N	N	
Ti-1.5Ni	<0.05	N	N	N	<0.05	N	N	N	
Ti-10V	<0.05	N	N	N	<0.05	N	N	N	
Aluminum Base									
2024-T3	1.3	>1400	X ^e	N	34.9	N	X ^e	N ^f	
6061-T6	30.4	>1400	N	N	56.6	N	N	N ^f	
Molybdenum Base									
T2M	<0.05	N	N	N	1.4	N	X ^d	N	

References: NE-302, CA-430

rates in aerated fluid were greater than 50 mpy. Stress corrosion cracking was not observed in tests with either aerated or nonaerated fluids.

Nickel Based Alloys

Inconel 625, Hastelloy S, Hastelloy G and Hastelloy C-276, and Inconel X-750 had uniform corrosion rates less than 0.05 mpy in deaerated fluid. Monel 400 did less well (2.8 mpy). Aeration greatly increased the corrosion of Inconel X-750. The uniform corrosion rates of the other nickel-based alloys were not affected much by aeration.

No pitting or stress corrosion cracking 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 general 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 to uniform corrosion (0.6 mpy) in nonaerated fluid, but aeration caused a ten-fold increase in the uniform corrosion rate. It was subject to crevice corrosion in both fluids.

These tests were in H₂S-free fluid. Experience has shown that copper-based alloys, especially cupronickels, are severely attacked in fluids containing H₂S (MI-305).

Titanium Based Alloys

All four titanium alloys were resistant to uniform corrosion, pitting and stress corrosion cracking in both aerated and deaerated fluid. Commercially pure titanium showed <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 fifteen days, was >1400 mpy. Crevice corrosion of 2024-T3 was severe (>50 mpy). A ten-fold increase in 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 (<0.05 mpy) in deaerated fluid; no local corrosion or stress corrosion cracking was detected. Aeration increased general corrosion to 1.4 mpy and significant crevice corrosion (>5 mpy but <50 mpy) occurred. No stress corrosion cracking was observed.

4.6.2 Results of Field Tests at Well Magmamax No. 1

Three test programs have been conducted at Well Magmamax No. 1 in the Salton Sea KGRA. One test series resulted in qualitative observations of corrosion after 30-day exposures of coupons in wellhead fluid. In the second program specimens were

tested in two 15-day test periods at the Bureau of Mines Geothermal Loop Experimental Facility. These tests were done in seven process streams typical of a dual flash binary power cycle. Uniform corrosion and pitting rates were measured, and crevice corrosion and stress corrosion cracking observations were made. The third test program was conducted at Lawrence Livermore Laboratory's (LLL) field test station. The tests employed an acidified mixture of steam and brine from Magmamax No. 1. Two kinds of tests were done with the acidified fluid. One series examined stress corrosion cracking and erosion-corrosion of specimens exposed to two-phase expander nozzle discharge. In the second series, uniform corrosion rates were measured electrochemically in 16-20-hour tests using exhaust fluid from the expander nozzles.

Table 4-42 shows the physical characteristics and chemical composition of fluids from three wells in the Salton Sea KGRA. The table indicates the range of temperature, pH, and chemical composition for wells in the resource area. The data for well Magmamax No. 1 (middle column) are for flashed fluid. Limited data are available describing the characteristics of fluids used in the three field test programs. The composition and temperature of fluids used in the field tests are somewhat different from those given in Table 4-42. The test conditions and results are described in the following sections.

4.6.2.1 Qualitative Corrosion Tests in Wellhead Fluid

Coupons of ten alloys (carbon steel, Type 316 L, E-Brite 26-1, Haynes Alloy 20 Mod, Carpenter 20Cb3, Inconel Alloy 625, Hastelloy G, Hastelloy C-276, commercially pure titanium, TiCode 12) were exposed to wellhead fluid from Magmamax #1 for 30 days (SY-029). Published information about the test procedures did not include data on fluid composition.

TABLE 4-42
CHARACTERISTICS OF GEOTHERMAL FLUIDS FROM THREE
WELLS IN THE SALTON SEA KGRA

<u>Fluid Characteristics</u>	<u>Flashed Fluid From Well Magmax No. 3</u>	<u>Flashed Fluid From Well Magmax No. 1</u>	<u>Mixture of Steam Condensate and Flashed Fluid From Well IID No. 1</u>
Temperature	280°C	265°C	316°C
Depth of Well	210m	875m	1591m
Enthalpy (Btu/lb)	432 Btu/lb	450 Btu/lb	-
pH	5.30	6.10	5.20
Conductance (µMHOS/cm)	257360.00	226297.00	--
<u>Chemical Composition (ppm):</u>			
TDS (Residue)	183,700	--	--
TDS (Sum)	153,300	203,106	257,800
SiO ₂	350.0	425.6	400.0
Na	36,340	46,282	50,400
K	7,820	7,789	17,500
Ca	14,550	23,090	28,000
Mg	780.0	107.6	54.00
Cl ⁻	93,650	120,374	155,000
HCO ₃ ⁻	60.00	59.69	150.00
CO ₃ ⁼	NR	NR	NR
H ₂ S	NR	NR	16.0
NH ₄ ⁺	340.0	557.7	409.0
B	210.0	NR	390.0
Ba	540.0	54.11	235.0
Br	NR	NR	120.0
Cs	NR	244.6	14.0
L ₁	49.00	74.00	215.0
Rb	NR	48.92	135.0
Sr	360	100.10	400.0
Al	NR	NR	4.200
As	10.00	0.1830	NR
Be	NR	0.078	NR
Co	NR	NR	NR
Cr	NR	0.290	NR
F	2.400	11.74	15.00
Fe	166.0	168.3	2,290
I	NR	NR	NR
Mn	410.0	NR	1,400
Ni	NR	1.030	NR
Pb	80.00	35.42	102.0
Zn	NR	276.9	540.0

NR - not reported

Reference: LA-312

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. Type 316 L, Haynes Alloy 20 Mod, Carpenter 20Cb3, and E-Brite 26-1 were pitted. No pitting was observed on the other specimens.

4.6.2.2 Corrosion Rates Measured in Seven Process Streams at the Geothermal Loop Experimental Facility

Corrosion rates were measured in two 15-day tests conducted at the Bureau of Mines' Geothermal Loop Experimental Facility (GLEF). The test facility employs fluid from well Magma-max No. 1 in seven process streams typical of those in a dual flash steam binary power cycle (wellhead, first and second flash steam, scrubbed first and second flash steam, and first and second flash fluids). Fluid characteristics for the seven process streams are summarized in Table 4-43.

Coupons of thirteen commercially available alloys were tested for weight loss and evidence of pitting and crevice corrosion. The coupons were fastened to rods using washers designed to minimize the extent of crevice areas. Stress corrosion cracking was studied by microscopic examination of a punch area. All samples were examined optically for evidence of local corrosion or cracking. Weight loss was measured after descaling, and pit depths were measured with an optical micrometer.

Rates of uniform corrosion and pitting calculated from maximum weight loss and pit depth are given separately for

TABLE 4-43
FLUID CHARACTERISTICS OF SEVEN GLEF PROCESS STREAMS IN TESTS
OF CORROSION RATE AT WELL MAGMAMAX NO. 1

<u>Process Stream</u>	<u>Fluid Characteristics</u>				
	<u>Temperature,</u> <u>°C(°F)</u>	<u>Pressure,</u> <u>psig</u>	<u>pH</u>	<u>Chloride</u> <u>Concentration,</u> <u>ppm</u>	<u>Bicarbonate</u> <u>Concentration,</u> <u>ppm</u>
Wellhead fluid	234(450)	280	5.07	112,100	5,300
First flash fluid	207(405)	200	5.11	127,700	5,580
First flash steam	NR	200	6.15	120	8,760
Scrubbed first flash steam	NR	200	NR	NR	NR
Second flash fluid	178(352)	120	5.5	127,600	5,510
Second flash steam	178(352)	120	6.1	50	2,800
Scrubbed second flash steam	NR	120	NR	NR	NR

Reference: CA-S-563

materials in each process stream in Tables 4-44 through 4-50. Crevice corrosion detected in areas where coupons were secured is indicated by X (detected) or N (not detected). Stress corrosion cracking is shown in the same way. In several process streams, significantly different uniform corrosion rates were measured in separate fifteen-day tests. In such cases, both rates are included in the table of results.

The results in Tables 4-44 through 4-50 indicate that pitting did not occur in tests of nickel and titanium alloys. While the tests were not designed to measure stress corrosion cracking, intergranular corrosion was observed for AISI Type 316 L.

Although precautions were taken to minimize crevice areas at coupon fastenings, crevice corrosion occurred on the iron-based alloys in all seven streams and on Hastelloy S in scrubbed second flash steam. Both pitting and uniform corrosion were observed between ceramic insulators and metal coupons. When pitting corrosion occurred in these areas, the pits were deeper than the pits in noncrevice areas. Crevice corrosion occurred least frequently in materials exposed to wellhead fluid and most frequently in materials exposed to scrubbed second flash steam.

For both 15-day test series, the nickel alloys, the titanium alloys, and alloy 29-4 and alloy 6X stainless steels had the greatest resistance to uniform corrosion in all streams. Measured rates were less than 0.1 mpy. E-Brite 26-1 and Type 316 L stainless steels had excellent resistance to general corrosion (less than 1 mpy) in all streams. Type 430 stainless steel had excellent corrosion resistance in all environments except the wellhead fluid and the scrubbed steam environments, where the corrosion rate was 1 to 5 mpy. The 1020 carbon and 4130 alloy

TABLE 4-44

**CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING WELLHEAD FLUID FROM
MAGMAMAX NO. 1 IN THE SALTON SEA KGRA**

	Wellhead Fluid*				
	General Corrosion (mpy) ¹	Pitting ² (mpy)	Crevice ³ Corrosion	SCC ⁴	Comments
Iron Base					
Carbon Steel (AISI 1020)	67	180 ^b	N	N	¹ Based on weight loss.
AISI 4130	13-33 ^a	150 ^{b,d}	N	N	² Based on maximum pit depth.
AISI Type 316L	0.7	68 ^b	X	X ^c	³ Effort made to minimize crevice area.
AISI Type 430	0.6-2.2 ^a	100 ^b	N	N	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.7	68 ^b	X	X ^c	
E-Brite 26-1	0.2	85 ^b	N	N	^a Results of 2 trials reported separately.
Allegheny-Ludlum 6X	<0.1	N	N	N	^b Width of pits is 4 to 5 times the depth.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^c Severe intergranular corrosion observed.
					^d Edge pitting.
Nickel Base					
Inconel 625	<0.1	N	N	N	(Performance of cast (ACI) alloy based on equivalent wrought alloy.)
Hastelloy S	<0.1	N	N	N	
Hastelloy G	<0.1	N	N	N	
Hastelloy C-276	<0.1	N	N	N	
Titanium Base					
Ti-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

KEY TO TABLE

* - 15 day exposure to Magmamax #1 wellhead fluid.
234°C (450°F), 280 psig, pH = 5.07, Cl⁻ = 112,000 ppm, HCO₃⁻ = 5,300 ppm

N - not detected.

X - detected.

Reference: CA-S-563

TABLE 4-45

**CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH FLUID
FROM WELL MAGMAMAX NO. 1 IN THE SALTON SEA KGRA**

	First Flash Fluid (Nonaerated)*				
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	Comments
Iron Base					
Carbon Steel (AISI 1020)	27-62 ^a	280 ^b	N	N	¹ Based on weight loss.
AISI 4130	3.8-6.8 ^a	100 ^b	N	N	² Based on maximum pit depth.
AISI Type 316L	0.1	27 ^b	X	X ^c	³ Effort made to minimize crevice area.
AISI Type 430	0.2	80 ^b	X	N	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.1	27 ^b	X	X ^c	
E-Brite 26-1	0.2	110 ^b	X	N	^a Results of 2 trials reported separately.
Allegheny-Ludlum 6X	<0.1	N	X	N	^b Width of pits is 4-5 times the depth.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^c Severe intergranular corrosion observed.
Nickel Base					
Inconel 625	<0.1	N	N	N	(Performance of cast (ACI) alloy based on equivalent wrought alloy.)
Hastelloy S	<0.1	N	N	N	
Hastelloy G	<0.1	N	N	N	
Hastelloy C-276	<0.1	N	N	N	
Titanium Base					
Ti-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

* - Fifteen day exposures to fluid from first flasher.

207°C (405°F), 200 psig, pH = 5.11, Cl⁻ = 127,700 ppm, HCO₃⁻ = 5580 ppm.

KEY TO TABLE

N - not detected.

X - detected.

Reference: CA-S-563

TABLE 4-46
CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING FIRST FLASH
STEAM FROM WELL MAGMAMAX NO. 1 IN THE SALTON SEA KGRA

	First Flash Steam (Nonaerated)*				
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	Comments
Iron Base					
Carbon Steel (AISI 1020)	26	150 ^{a, c}	N	N	¹ Based on weight loss.
AISI 4130	7.7	78 ^a	N	N ^b	² Based on maximum pit depth.
AISI Type 316L	0.4	32 ^a	N	X ^b	³ Effort made to minimize crevice area.
AISI Type 430	0.8	88 ^a	X	N ^b	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.4	32 ^a	N	X ^b	
E-Brite 26-1	0.2	90 ^a	X	N	^a Width of pits is 4-5 times the depth.
Allegheny-Ludlum 6X	<0.1	39 ^a	N	N	^b Severe intergranular corrosion.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^c Edge pitting.
Nickel Base					
Inconel 625	<0.1	N	N	N	(Performance of cast (ACI) alloy based on
Hastelloy S	<0.1	N	N	N	equivalent wrought alloy.)
Hastelloy G	<0.1	N	N	N	
Hastelloy C-276	<0.1	N	N	N	
Titanium Base					
Ti-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

* - Steam from first flasher (unscrubbed).
200 psig, Cl⁻ = 120 ppm, HCO₃⁻ = 8,760 ppm.

KEY TO TABLE

N - not detected.
X - detected.

Reference: CA-S-563

TABLE 4-47

CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SCRUBBED FIRST FLASH

STEAM FROM WELL MAGMAX NO. 1 IN THE SALTON SEA KGRA

Scrubbed First Flash Steam* (Nonaerated)					Comments
General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴		
<u>Iron Base</u>					
Carbon Steel (AISI 1020)	21-40 ^a	83 ^b	X	N	¹ Based on weight loss.
AISI 4130	18	97 ^b	N	N	² Based on maximum pit depth.
AISI Type 316L	0.2	130 ^b	X	N ^c	³ Effort made to avoid crevice area.
AISI Type 430	0.4	120 ^b	N	N	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.2	130 ^b	X	N ^c	
E-Brite 26-1	0.2	56 ^b	N	N	^a Results of two trials reported separately.
Allegheny-Ludlum 6X	<0.1	37 ^b	N	N	^b Width of pits is 4-5 times the depth.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^c Severe intergranular corrosion.
<u>Nickel Base</u>					(Performance of cast (ACI) alloy based on equivalent wrought alloy.)
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-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

* - Fifteen day exposures to scrubbed first flash steam.
200 psig.

KEY TO TABLE

N - not detected.

X - detected.

Reference: CA-S-563

TABLE 4-48

CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SECOND FLASH FLUIDFROM WELL MAGMAX NO. 1 IN THE SALTON SEA KGRA

	Second Flash Fluid (Nonaerated)*				
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	Comments
<u>Iron Base</u>					
Carbon Steel (AISI 1020)	48	240 ^b	N	N	¹ Based on weight loss.
AISI 4130	2.2-10.3 ^a	88 ^b	N	N	² Based on maximum pit depth.
AISI Type 316L	0.3	44 ^c	X	N ^c	³ Effort made to avoid crevice area.
AISI Type 430	0.6	41 ^b	X	N ^c	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.3	44 ^b	X	N ^c	
E-Brite 26-1	<0.1	39 ^b	X	N	^a Results of two trials reported separately.
Allegheny-Ludlum 6X	<0.1	29 ^b	N	N	^b Width of pits is 4-5 times the depth.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^c Severe intergranular corrosion.
<u>Nickel Base</u>					
Inconel 625	<0.1	N	N	N	(Performance of cast (ACI) alloy based on
Hastelloy S	<0.1	N	N	N	equivalent wrought alloy.)
Hastelloy G	<0.1	N	N	N	
Hastelloy C-276	<0.1	N	N	N	
<u>Titanium Base</u>					
Ti-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

* - Fifteen day exposures to fluid from second flasher.
178°C (352°F), 120 psig, Cl⁻ = 127,600 ppm, HCO₃⁻ = 5510 ppm.

KEY TO TABLE

N - not detected.
X - detected.

Reference: CA-S-563

TABLE 4-49
CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SECOND FLASH
STEAM FROM WELL MAGMAX NO. 1 IN THE SALTON SEA KGRA

	Second Flash Steam*				
	General Corrosion (mpy) ¹	Pitting (mpy) ²	Crevice Corrosion ³	SCC ⁴	Comments
<u>Iron Base</u>					
Carbon Steel (AISI 1020)	25	200 ^a	N	N	¹ Based on weight loss.
AISI 4130	8.2	110 ^a	N	N _b	² Based on maximum pit depth.
AISI Type 316L	0.3	83 ^a	X	X _b	³ Effort made to avoid crevice area.
AISI Type 430	0.5	100 ^a	X	N _b	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.3	83 ^a	X	X _b	
E-Brite 26-1	0.3	100 ^a	X	N	^a Width of pits is 4 to 5 times the depth.
Allegheny-Ludlum 6X	0.1	37 ^a	X	N	^b Severe intergranular corrosion.
Allegheny-Ludlum 29-4	0.1	N	N	N	(Performance of cast (ACI) alloy based on equivalent wrought alloy.)
<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-1.5Ni	0.1	N	N	N	
TiCode-12	0.1	N	N	N	

* - Fifteen day exposures to steam (unscrubbed) from second flasher.
 178°C (352°F). 120 psig, pH = 6.10, Cl⁻ = 50 ppm, HCO₃⁻ = 2800 ppm.

KEY TO TABLE

N - not detected.
 X - detected.

Reference: CA-S-563

TABLE 4-50
CORROSION RATES MEASURED IN FIFTEEN-DAY TESTS USING SCRUBBED SECOND FLASH
STEAM FROM WELL MAGMAX NO. 1 IN THE SALTON SEA KGRA

	Scrubbed Second Flash Steam* (Nonaerated)				
	General Corrosion ¹ (mpy)	Pitting ² (mpy)	Crevice Corrosion ³	SCC ⁴	Comments
Iron Base					
Carbon Steel (AISI 1020)	18-27 ^a	140 ^b	X	N	¹ Based on weight loss.
AISI 4130	25	150 ^b	X	N	² Based on maximum pit depth.
AISI Type 316L	0.2	265 ^b	X	N ^c	³ Effort made to avoid crevice area.
AISI Type 430	1.4	300 ^b	X	N	⁴ Based on microscopic examination of punch area.
ACI Type CF-3M	0.2	265 ^b	X	N ^c	
E-Brite 26-1	0.1	240 ^b	X	N	
Allegheny-Ludlum 6X	<0.1	29 ^b	X	N	^a Results of 2 trials reported separately.
Allegheny-Ludlum 29-4	<0.1	N	N	N	^b Width of pits is 4 to 5 times the depth.
Nickel Base					
Inconel 625	<0.1	N	N	N	^c Severe intergranular corrosion.
Hastelloy S	<0.1	N	X	N	(Performance of cast (ACI) alloy based on equivalent wrought alloy.)
Hastelloy G	<0.1	N	N	N	
Hastelloy C-276	<0.1	N	N	N	
Titanium Base					
Ti-1.5Ni	<0.1	N	N	N	
TiCode-12	<0.1	N	N	N	

* - Fifteen day exposures to scrubbed steam from second flasher.
120 psig.

KEY TO TABLE

N - not detected.
X - detected.

Reference: CA-S-563

steels had the poorest corrosion resistance in all streams and were more severely corroded in the fluids than in the steams.

In several of the streams, the average corrosion rates of 1020 carbon steel, 4130 alloy steel, and 430 stainless steel were significantly different for each of the two 15-day series of corrosion tests. However, the corrosion rates for each set of metal samples in any one stream for a single 15-day test series were in good agreement. Where the average corrosion rates of each 15-day test series were significantly different, both rates are reported.

With the exception of Allegheny-Ludlum 29-4, all of the iron-based alloys were pitted in one or more streams. The 1020 carbon steel pitted most severely in liquid streams while the alloy steels pitted worse in steam. Pitting was more severe in "clean" steam than in "dirty" steam. The widths of the pits were four to five times greater than their depths. This is a mild form of attack and indicates that corrosion over the surface of the metal is proceeding faster than penetration into the body of the metal.

4.6.2.3 Tests in Acidified Salton Sea Geothermal Fluid

Lawrence Livermore Laboratory (LLL) has shown that acidification of Magmamax No. 1 fluid to a pH <4.5 will prevent scale formation for "a substantial period of time." The concentration of HCl 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 (AU-064, TA-136).

The field tests were conducted using a mobile test bed which includes a flash steam separator and has the capability

for producing both pure brine or steam and two-phase mixtures. Test fluids are discharged through two-phase expander nozzles. There are provisions for modifying the test fluids by adding chemicals. The test equipment includes simulated turbine cases, atmospheric pressure chambers containing static wearblades.

The results of two series of tests are reported here. In one series, corrosion specimens were mounted on the base of the fixed wearblades to test potential turbine materials for resistance to erosion, pitting and crevice corrosion, and stress corrosion cracking. Specimens of the alloys to be tested 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 100°C for periods varying from 7.5 to 110 hours. The nozzle discharge rate was 240 mps (787 fps). Fluid pH varied from 2.5 to 4.5. The alloys tested and the test conditions are summarized in Table 4-51. 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 non-ferrous 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.

TABLE 4-51

RESULTS OF EROSION-CORROSION TESTS OF POSSIBLE TURBINE COMPONENT
ALLOYS IN ACIDIFIED SALTON SEA GEOTHERMAL FLUID

Material	Condition	Exposure (hrs)	Ave pH	Expressed Sample ¹ 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
2.25 Cr-1 Mo 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
18 Cr - 2 Mo steel	Mill annealed	59.5	4.5	Some pits 0.1 - 0.2 mils deep
29 Cr - 4 Mo 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 538°C for 4 hours	37	3.1	Many pits 0.6 - 2.0 mils deep
Ti - 4 Al - 3 Mo - 1 V	Mill annealed	22.5	3.7	Very few pits ~ 0.1 - 0.3 mils deep
Ti - 8 Al - 1 Mo - 1 V	Duplex milled and annealed	25	2.5	Many cracks 1.0 - 2.0 mils deep
Ti - 6 Al - 4 V	Mill annealed	25	2.5	Crack ~ 0.6 mils deep at base of pre-stress notch
Ti - 6 Al - 4 V	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 - 6 Al - 4 V	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 - 6 Al - 4 V	α - β annealed, air cooled stress relieved	22.5	3.7	No cracks found

¹U-bend stress corrosion cracking specimens with tensile surface exposed to two-phase nozzle discharge. Fluid was acidified Magmax No. 1 brine at ~ 100°C and 240 m/s.

Reference: AU-064

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 86 to 98°C. Table 4-52 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.

TABLE 4-52

ELECTROCHEMICAL CORROSION RATES MEASURED IN ACIDIFIED FLASHED
FLUID FROM WELL MAGMAMAX NO. 1 AT THE SALTON SEA KGRA

<u>Material</u>	<u>General Corrosion¹ (mpy)</u>
<u>Ferrous Alloys</u>	
Carbon steel (AISI 1018)	100
1 Cr - 0.2 Mo (Soo-90)	76
0 Cr - 0.5 Mo (A-204 Grade B)	12
0.9 Cr - 0.5 Mo (A-387 Grade 12)	14
2.2 Cr - 1 Mo (A-387 Grade 64)	29
3.7 Cr - 8 Mo (4-43)	15
5.6 Cr - 0.5 Mo	8-23
9 Cr - 1 Mo	20
Type 317 LM	0.3
Carpenter 20 Cb-3	0.5
E-Brite 26-1	1.0
29 Cr - 4 Mo	1.5
29 Cr - 4 Mo - 2 Ni	0.1
<u>Non-Ferrous Alloys</u>	
Ti-6Al-4V	0.1
Hastelloy C-276	0.06
Inconel 625	0.3

¹Rates determined by electrochemical method during final two hours of 16-20 hour tests.

TEST CONDITIONS:

Acidified Magmamax No. 1 fluid with pH = 2.0-4.5. Temperature 86-98°C.

REFERENCES: TA-136, AU-064

Section 4 presented available data from tests of materials performance in geothermal fluids. Most of these tests measured the rates of uniform corrosion and localized (pitting and crevice) corrosion of coupon specimens, though some tests of stress corrosion cracking of 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 uniformly or from pitting at a specific fluid composition, temperature, and flow rate. But the uniform and localized corrosion rates described in Section 4 do not supply all of the information needed to specify construction materials for piping, vessels, or process equipment.

There are three reasons they do not tell the whole story. First, the 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.

Second, metallic construction materials are subject to other forms of attack besides uniform, pitting and crevice corrosion.

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 exposed under stress to aqueous environments containing even small amounts of H_2S . Hydrogen blistering, another form of attack, causes rupture of metallic materials when hydrogen trapped in voids accumulates at a sufficient pressure. Improper heat treatment or welding can result in intergranular corrosion near

grain boundaries (weld decay) which causes alloys to disintegrate or lose strength. Dealloying, dissolution of one component of an alloy, is another form of corrosion. Failures also occur due to corrosion fatigue when cyclic stresses occur in a corrosive environment.

Finally, the rate at which metals deteriorate depends on some factors that are not taken into account in tests using coupons. In practice it is not a metal coupon that fails due to metal deterioration but a pipe, vessel, pump, or other equipment item fabricated from metal. The rate of metal deterioration or the mode of corrosive attack also depend on fabrication practices, equipment configuration and geometry, and stresses that occur during operation.

This section describes the forms and mechanisms of corrosive attack that can occur in geothermal process streams. These generalizations are especially useful when materials must be specified for conditions at which tests have not been done. If the corrosion rate of a material has been tested at the stream conditions of interest, this information is still useful. It explains the effects of fabrication practices, equipment configuration, and operating stresses. And it identifies some additional ways materials can deteriorate.

The information is presented in three parts. Modes of corrosive attack in wellhead and flashed liquid streams are described first. The forms of failure that can occur in liquids are described for mild and low alloy steels (Section 5.1), stainless steels (Section 5.2), titanium alloys (Section 5.3), nickel alloys (Section 5.4), copper alloys (Section 5.5) and cobalt, zirconium and aluminum (Section 5.6). Table 5-1 is a guide to the information about the performance of specific metals in liquid streams given in Sections 5.1 through 5.6. It summarizes

TABLE 5-1

**FORMS AND CAUSES OF CORROSION FOR METALS IN LIQUID GEOTHERMAL
STREAMS (SUMMARY OF INFORMATION PRESENTED IN SECTIONS
5.1 THROUGH 5.6) AND WAYS TO PREVENT ATTACK**

Material	Major Forms of Corrosion	Main Environmental Factors	Limits and Precautions	Other Comments
<u>Mild and Low Alloy Steels</u>				
	uniform	pH chloride flow velocity	Rapid rate increase below pH 6. Rapid rate increase above 22 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 impingement on steel.
	pitting, crevice	temperature chloride scale	Susceptibility increases with increasing temperature and chloride concentration. Remove mill scale; avoid deposits.	See 5.1.2 for low alloy additions. Avoid mechanical crevices.
	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 temperatures.	Complex interactions; see 5.1.4.
	hydrogen blistering	H ₂ S	Use void-free materials.	Possible at very low H ₂ S concentrations; see 5.1.5.
	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.
<u>Stainless Steels</u>				
ferritic alloys	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; O ₂ is a hazard. Higher alloys are much more resistant; Cr and Mo most effective alloying agents; see 5.2.3.
	intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures; see 5.2.5.	
austenitic alloys	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 Cl ⁻ , O ₂ , T; some alloys more resistant; see 5.2.4; 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 increases with Mo content; avoid mechanical crevices.
	intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures; see 5.2.5.	
martensitic alloys	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 5.2.6.
cast alloys	as above			See comments for equivalent wrought alloy; good crevice corrosion resistance needed for pumps and valves
<u>Titanium Alloys</u>				
	crevice, pitting	chloride temperature pH	Maximum temperature for resistance depends on chloride and pH, see 5.3.2.	Several alloys have much better resistance than pure Ti. Pre-cracked Ti may undergo stress corrosion cracking. (5.3.4)
	galvanic coupling	electrical contact with more active metal	Coupling to large areas of more active metal may cause hydrogen embrittlement of Ti; see 5.3.3.	
<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 5.4.1. May be susceptible to hydrogen embrittlement when coupled to steel.
<u>Copper Alloys</u>	pitting, uniform, dealloying stress corrosion cracking	H ₂ S chloride, temperature ammonia, pH	H ₂ S as low as 0.1 ppm can cause attack. See 5.3 for pH and alloy dependence.	Usefulness limited in H ₂ S environment.
<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; also see 5.1.4.
zirconium and tantalum				Resistant to low pH, hot chloride solutions.
aluminum	pitting, crevice	Hg and Cu ions, pH, chloride, temperature	Poor results obtained in geothermal tests.	May be useful as exterior siding and construction material.

the information presented for each metal, defining the kinds of corrosive attack that can occur for a particular metal and the fluid or process stream characteristics that determine corrosiveness. The conditions under which attack is minimized are defined and precautions for design, fabrication and operation are given.

Materials performance in condensate (Section 5.7) and steam (Section 5.8) is treated in the last two sections. While much of the information given for liquid streams in Sections 5.1 through 5.6 is also applicable to condensate and steam environments, there are some additional considerations for these streams. Corrosion fatigue and erosion caused by exfoliation or droplet impingement are most likely to occur in these environments.

5.1 Mild and Low Alloy Steels

The low cost, availability, and ease of fabrication of low 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.

5.1.1 General Guidelines for Using Mild Steels

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 corrosion as well as localized corrosion and will severely limit the use of low carbon steels. The application of mild steels to geothermal environments requires 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 moderate salinity geothermal fluids are due mainly to the reducing, oxygen-free nature of the fluids. The introduction of small 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 5-1 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 100°C at which point it increases again (CR-162). The electrochemical reaction rate increases with temperature.

Figure 5-1. Effect of Oxygen on Uniform Corrosion Rate of 1010 Mild Steel in 250°F Seawater (Based on data presented in GE-117)

Aeration damage during plant operation should be minimized by guarding against leaks in the lower temperature vacuum sections of the plant. The highest potential for serious damage from aeration occurs due to inleakage during plant outages or layups. Stagnant conditions are conducive to crevice and pitting corrosion promoted by oxygen. Oxidation of ferrous ions and H_2S 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 5-7 ft/sec. Localized, uncontrolled flashing in geothermal streams can cause high flow

rates in the system. This action can produce bubbles of noncondensable gas which can cause impingement attack. Entrained solids in the stream can cause erosion-assisted corrosion. The relative hardness of particle and metal has little effect on this type of corrosion.

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 down-hole applications, may be subject to severe cavitation damage. The CO_2 content of many geothermal fluids can cause an apparent vapor pressure that exceeds steam table values by tens to hundreds of psi. Caution in design and material selection is required.

Effects of high velocities are illustrated in Figure 5-2 for seawater at 250°F.

Figure 5-2. Weight-Loss Corrosion Rates of Mild Steel in High Velocity, High Temperature Oxygen-Free Seawater. (Based on data presented in GE-117)

Scaling - Some mechanical protection 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 H_2S is increased in acidic environments such as this.

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 perforation of thick-walled steel components.

Chemical cleaning solutions used to remove scale should be evaluated carefully since some types (such as inhibited HCl) accelerate corrosion of mild steel. Severe attack can occur if aggressive cleaning solution is trapped in or under incompletely removed scale.

Galvanic Coupling - Carbon steels will be anodic to high alloy 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 the dissimilar metals are close together and the area of steel exposed to the liquid is small compared to that of the more noble metal. Some noble metals may be 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 5-3. The corrosion rate of a given metal will be accelerated when it is galvanically coupled to a metal with a more positive open circuit potential. A similar order was observed in Heber geothermal fluids during short-term measurements (SY-028). 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 protection. Leaks and sprays of saline fluid combined with air and occasional H₂S emissions can produce rapid attack. Protective coatings should be used to minimize uniform and localized attack of exterior surfaces. High quality coatings should be specified to avoid localized attack at pores or exposed areas.

Steel Specification - Sulfide stress cracking and hydrogen blistering can be controlled to a large extent by use of low strength, metallurgically clean and void-free steel (see Sections 5.1.4 and 5.1.5). 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 5.1.2.

5.1.2 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.

Figure 5-3. Galvanic Series of Selected Alloys in Hot Acid Treated/Deaerated Seawater (GE-117)

Corrosion results for mild and low alloy steels in geothermal field tests are shown in Table 5-2. Although obtained in a wide range of environments, uniform corrosion rates are about 1 to 10 mpy when the pH is greater than 6 and the chloride concentration is less than 2%. Localized corrosion occurs to some extent in most fluids and becomes predominant in fluids where uniform corrosion is less severe.

The relative importance of uniform and localized corrosion depends mainly on pH and chloride concentration. Above a critical pH, uniform corrosion rates are relatively low, and the major problem for mild steels is localized corrosion. Since pitting and crevice corrosion are more severe forms of attack than uniform corrosion, plain 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 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.

TABLE 5-2
CORROSION OF PLAIN AND LOW ALLOY STEELS IN NATURAL GEOTHERMAL LIQUIDS

Site/Liquid Source	Temp (°C)	pH ¹	Chloride Concentration (ppm)	Uniform Corrosion (mpy)	Local Corrosion ²	Steel Type
<u>East Mesa</u>						
Wellhead	150	5.6-5.8	13,350	6.0	-	AISI 1010
	150	5.6-5.8	13,350	5.5	-	ASTM A53B
	150	5.6-5.8	13,350	6.8	-	AISI 4130
	130	5.6	11,800	3.2	C	AISI 1020
	130	5.6	11,800	1.9	C	AISI 4130
	50	5.6-5.8	13,350	1.7	-	AISI 1010
	50	5.6-5.8	13,350	1.8	-	ASTM A53B
	50	5.6-5.8	13,350	3.5	-	AISI 4130
First Flash	-	6.8	12,060	2.4	C	AISI 1020
	-	6.8	12,060	1.6	C	AISI 4130
Second Flash	-	8.1	12,740	3.1	C	AISI 1020
	-	8.1	12,740	1.2	C	AISI 4130
<u>Heber</u>						
Wellhead	~200	7.1	9,000	2.2*	N*	AISI 1010
<u>Raft River</u>						
Wellhead	130	7.05-7.40	780	1.8	P, C	AISI 1018
	130	7.05-7.40	780	1.9	P, C	ASTM A515 (low carbon)
	130	7.05-7.40	780	0.8	P, C	AISI 4130
	130	7.05-7.40	780	1.1	P, C	ASTM A242 (COR-TEN)
<u>Salton Sea</u>						
Wellhead	234	5.07	112,000	67	P	AISI 1020
	234	5.07	112,000	13-33	P	AISI 4130
First Flash	207	5.11	127,000	27-62	P	AISI 1020
	207	5.11	127,000	3.8-6.8	P	AISI 4130
Second Flash	178	5.50	127,600	48	P	AISI 1020
	178	5.50	127,600	2.2-10.3	P	AISI 4130
<u>Wairakei, N.Z.</u>						
Wellhead	240	-	1,500	<1.0	-	Carbon steels
	240	-	-	<1.0	-	Carbon Mn steels
	121	-	1,500	2	-	Carbon steels
	50-100	-	1,500	1.0-10	-	Carbon steels
	50-100	-	-	1.0-10	-	Carbon Mn steels
Separated Water	125	-	-	<1.0	-	Carbon steels
	125	-	-	<1.0	-	Carbon Mn steels

* Not descaled.

¹ Measured near ambient temperature

² P - pitting

C - crevice

N - not detected

Pitting and crevice corrosion rates given in Section 4.

The growth rate of pits is difficult to predict. If initial testing in a geothermal fluid indicates pit initiation, pit growth rates should be measured periodically during extended testing.

5.1.2.1 Effect of pH on Uniform Corrosion

Low pH affects the uniform corrosion rate of low carbon and low alloy steels. This effect is illustrated in Figure 5-4 for relatively low temperature degassed seawater. Acidification of East Mesa Fluid at 150°C from pH 5.7 to pH 4.7 increased corrosion rates by a factor of 3 to 4 (SH-381). The critical pH below which rapid corrosion can occur is in the range of pH 5 to 7. 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 (Section 5.2).
- The corrosivity of dissolved CO₂ and H₂S 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. This pH can be quite different from bulk liquid pH in crevices, under scale, and near trapped gas.

Figure 5-4. Effect of Seawater pH on the Corrosion Rate of 1010 Mild Steel at a Typical Deaerator Temperature (GE-117)

5.1.2.2 Effect of Chloride on Uniform and Localized Corrosion

The effect of chloride concentration on uniform corrosion of mild steels can be discussed in terms of two main concentration regions.

- High corrosion rates of mild steels begin to occur at high chloride concentrations (about 10 to 15% as NaCl).
- Changes in chloride concentration below about 3% (as NaCl) have relatively little effect on uniform corrosion rate.

The transition point between these two regions is uncertain, but the chloride concentrations in all present KGRA fluids fall into one of the above two regions.

The abrupt increase in corrosion rate with chloride concentration is illustrated by the laboratory results in Figure 5-5 (SH-381). Later results indicate that even higher corrosion rates may occur above the breakpoint at 10% NaCl shown in the figure. 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 (PO-230). Allowances can be made for uniform corrosion of thick-walled components in high chloride solutions; but localized corrosion is also more likely and establishing allowances for this corrosion is difficult.

Figure 5-5. Average Corrosion Rate of Carbon Steels vs Salinity 250°C - pH 4.5-4.8
Pressure 68.9 Bars (1000 psig)
Oxygen - <0.01 ppm
(Based on data in SH-381)

The low sensitivity of uniform corrosion rates in low chloride solutions relative to a high chloride solution is qualitatively shown by results obtained in geothermal fluids with

different chloride concentrations (Table 5-2). This trend is supported by laboratory studies at lower temperatures with other variables held constant (CH-A-453).

At high 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 pitting potential. Pitting is possible if the electrode 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 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 present 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 25°C is illustrated in Figure 5-6. According to this, steels should be relatively immune to pitting in oxygen-free chloride solutions at 25°C since the corrosion potential is more active (negative) than the pitting potential. The difference is small at higher chloride concentrations and

Figure 5-6. Pitting and Corrosion Potentials of Steel in Oxygen-Free Chloride Solutions 25°C. Pitting Potential Curve is from Equation by K. J. Vetter in ST-566, p. 240. Corrosion Potentials are Representative Values. The Slope of the Corrosion Potential Line is Based on Laboratory Measurements (CH-A-453)

trace amounts of oxygen could raise the corrosion potential above the pitting potential.

5.1.2.3 Effect of Temperature on Uniform and Localized Corrosion

Specific effects of temperature on uniform corrosion of mild steels are difficult to define due to the scarcity of experimental data in the 100° to 250°C region and to simultaneous changes in the equilibrium distribution of chemical species with temperature.

A tentative finding based on geothermal results (Table 5-2) is that uniform corrosion rates do not increase as rapidly with increasing temperature (in the 100°C to 250°C range) as early experimental studies at temperatures less than 100°C would indicate; the latter generally yield activation energies of 10 to 12 kcal/gmole for iron and mild steels. A decrease in corrosion rate of low carbon steels with increasing temperature in simulated geothermal fluids has been reported at a constant CO₂ partial pressure (SH-381). This phenomenon might be explained in terms of formation of more protective magnetite films at high temperature. At constant CO₂ partial pressure, actual solution pH may increase with increasing temperature, providing an additional reason for the observation. These results may simulate a binary cycle with very limited flashing.

Laboratory measurements of the corrosion rate of A212B steel as a function of temperature are shown in Figure 5-7. Although of interest, these measurements may not be typical of most geothermal sources due to the high chloride concentration and the absence of CO₂ which affects the temperature dependence of pH.

Figure 5-7. Corrosion Rate of A212B Carbon Steel in Deaerated 4 M NaCl as a Function of pH and Temperature (PO-230)

Although little data are available, variations in temperature may have as great an influence on pitting as changes in chloride concentration. Figure 5-8 shows the effect of temperature on the pitting and corrosion potentials in a 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 5-8 at 25°C and 200°C are average values measured in Heber fluid (SY-028). The linear relationships and ranges shown are assumptions. In deaerated seawater the corrosion potential increases above about 120°C (SM-A-191). In relatively alkaline low-chloride solutions the pitting potential may go through a minimum and then increase (become more positive) at high temperature (ST-566, p. 415).

In spite of the variability noted, the results show that temperature can have a substantial effect on susceptibility to localized corrosion.

5.1.2.4 Effect of Other Key Species on Uniform, Pitting, and Crevice Corrosion of Low Alloy Steels

The key species considered are H_2S , H_2CO_3 , NH_4^+ , and $\text{SO}_4^{=}$. 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 and because they control pH. Sulfate becomes important only in those geothermal fluids which have low chloride concentrations. Small amounts of oxygen leaked into a geothermal system produce more localized corrosion than the normal environmental factors discussed. This is primarily a design and operation problem in low-pressure equipment and during shutdown.

Figure 5-8. Pitting and Corrosion Potentials of Steel as a Function of Temperature in Heber Geothermal Fluid. Data at 25° and 200°C are from SY-028. This graph is for illustration of trends only; linear forms are assumed for lack of other data. See Table 4-22 for fluid chemistry.

H₂S - Hydrogen sulfide in acidic media can greatly accelerate steel corrosion (MA-A-770, IO-A-21). An iron sulfide layer can form on steels in the presence of H₂S, 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 H₂S attack. Crevice or pitting corrosion initiated by other means may be accelerated by H₂S which stimulates the anodic dissolution reaction.

CO₂ - Dissolved CO₂ indirectly affects corrosion by the buffering action of the aqueous species H₂CO₃, HCO₃⁻, and CO₃⁼. Release of CO₂ during flashing increases the pH of the flashed fluid. Maintaining CO₂ pressure while cooling geothermal fluids may decrease pH due to the temperature dependence of the equilibrium constants. In mildly acidic solutions (pH about 3 to 5), H₂CO₃ accelerates the uniform corrosion of mild steels. Results obtained in 1% NaCl, 0.05 to 1.0 atm CO₂ up to 80°C indicate that this effect is due to acceleration of the cathodic (hydrogen evolution) reaction (DE-A-315). Therefore, H₂CO₃ should not have as adverse an effect on localized corrosion rates as H₂S, which stimulates the anodic (metal dissolution) reaction.

NH₃ - Flashed ammonia absorbed in condensate tends to neutralize the acidity produced by CO₂ and H₂S, but the acidic species are present in much larger amounts than NH₃ in most geothermal sources. Limited seawater desalination tests showed that the uniform corrosion rate of mild steels increased approximately 65% when 15 ppm NH₃ (in solution) was added as ammonia gas (GE-117).

SO₄⁼ - 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.

5.1.2.5 Effect of Low Alloy Additions on General Corrosion

In moderate chloride and pH systems, the uniform corrosion rates of low alloy steels are somewhat lower than low carbon steels, but the absolute difference is usually small. Pitting and crevice corrosion attack is similar to mild steels and sometimes more severe for low alloys. High-strength low alloy steels may be more susceptible to sulfide stress cracking or stress corrosion cracking.

Identification of resistant low alloy steels may be necessary for utilization of high chloride, low pH geothermal fluids due to the high corrosion rates of plain steels. Pitting and crevice corrosion of low alloy steels in these environments are major concerns. Further testing is being conducted by Lawrence Livermore Laboratory.

The limited success in moderate salinity-pH fluids should not preclude further testing of low alloy steels. Long term tests in a seawater boiler at about 200°C showed that steels containing 0.2% to 0.3% copper had lower pitting rates than plain steels (BU-A-307). 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

(GE-117). 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.

5.1.3 Stress Corrosion Cracking of Low Alloy Steels

Stress corrosion cracking of low alloy steels in H_2S -free chloride solutions has been observed. 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 (BA-556, HU-200). See Table 5-3 left column for characteristics of SCC.

5.1.4 Sulfide Stress Cracking of Low and Middle Alloy Steels

Sulfide stress cracking is the brittle failure of hard, high strength alloys when they are exposed under stress to environments containing even small amounts of H_2S in an aqueous phase. Often these environments are not particularly severe from a general or local corrosion standpoint. The failure is sudden, catastrophic, and without warning. There is little or no evidence of metal loss. See Table 5-3 right column for characteristics of SCC.

Sulfide stress cracking (SSC) has been a problem at Wairakei, N.Z. (FO-120, SM-160, MA-682, FO-119), and Cerro Prieto, Mexico (GE-119). It places definite restrictions on materials and design for any geothermal resource containing H_2S . These limitations are the result of a complex interaction of a number of factors involving both the environment and the material. Resistance to SSC generally increases with increasing temperature, decreasing stress, decreasing yield strength, decreasing H_2S concentration, and increasing pH. The effects of

TABLE 5-3
COMPARISON OF SCC AND SSC IN GEOTHERMAL ENVIRONMENTS *

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. fcc steels most sensitive	3. bcc steels most sensitive fcc 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 O ₂ causes drastic increase in severity of attack	6. ppm O ₂ 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.

*Some authors consider SSC to be a subset under SCC. In this report, SCC and SSC are treated as separate processes, compared above.

H₂S concentration, pH, stress, and yield strength are interdependent and more significant than other factors such as microstructure and alloy composition. A discussion of these factors is presented first. Then discussion of the interaction of these factors is given, followed by comments on other less significant factors.

5.1.4.1 Effect of H₂S Concentration

The failure (cracking) of stressed materials in high H₂S environments (above 15-30 ppm) occurs in 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 (HU-199, HU-200). Concentrations of H₂S as low as 20 ppb accelerate hydrogen entry into steel (HU-A-233). Concentrations less than 0.1 ppm have caused failure in long-term tests.

5.1.4.2 Effect of Stress and Yield Strength (Hardness)

Sulfide stress cracking is stress dependent and the total stress to which the steel is subjected must be considered, including applied tensile stress, residual tensile stresses resulting from phase transformation during or after heat treatment, thermal stress, and cold deformation during fabrication and service (VO-067, NA-383, BA-550, HU-200). Even 1% cold work can lower the threshold stress about 30% (BA-563). Cold worked parts should be heat treated to relieve residual stress. A notch greatly reduces threshold stress. Threshold stress is the greatest applied stress which does not cause SSC failures. Notches greatly increase 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.

5.1.4.3 Interaction of H₂S Concentration, Stress, and Yield Strength

The NACE standard for sour service is 90-100 ksi yield strength, or Rc 22. This is based on performance of steels stressed to 100% YS in NACE solution [5% NaCl, 0.5% acetic acid saturated with H₂S] (NA-423).

The actual limitations on usable hardness are a complex interaction of yield strength, applied stress, temperature and concentration of H₂S. Figure 5-9 shows the effect of limiting applied stress on usable hardness.

While a given steel may be utilized at much greater yield strength and hardness (~128 ksi, Rc 30) if stresses are limited to 60% of yield, calculation shows that the point of maximum return on usable strength has been passed (HU-200).

Figure 5-10 illustrates the increase in usable hardness with decreasing H₂S concentrations.

5.1.4.4 Effect of Microstructure and Composition

Strength and hardness are inadequate for defining susceptibility to SSC (BO-256). Microstructure affects the SSC resistance of steels with the same hardness, while composition

Figure 5-9. Approximate Correlation of Hardness, Time to Failure and Applied Stress for Carbon Steels (3000 ppm H_2S in 5% NaCl) (Based on data presented in HU-199)

Figure 5-10. Approximate Correlation of Failure Time for Carbon Steels in 5% NaCl Containing Various Concentrations of H_2S (Based on data presented in HU-199)

is significant only as it affects hardenability and microstructure (SN-060, SN-061, FR-233, HU-200). Quenched and tempered steels are superior to normalized and tempered steels of comparable yield strengths (SN-060). Normalized and tempered steels are superior to normalized steels (KA-280). Figure 5-11 illustrates the superiority of quenched and tempered steel over normalized and tempered steels.

Figure 5-11. Yield Strength-Threshold Stress Relationship for Low Alloy Steels (SN-060)

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.

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 phosphorous are less resistant (SN-061).

The next most resistant microstructures contain coarse globular and/or laminar carbides (SN-061). Sulfur also tends to form "stringers" of inclusions which favor cracking (OH-S-039). Laboratory heats of very low sulfur steels or steels with trace lanthanide additions, are very resistant to SSC (OH-S-039, SN-061, TR-090).

Microstructures containing untempered martensite have the worst 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 Rc 22. These microstructures can occur in either Q and T, or N and T steels if the tempering temperature exceeds the lower critical temperature (austenizing temperature). Additions of nickel and manganese reduce the lower critical temperature, increasing the risk of forming untempered martensite. This accounts for the poor performance of steels containing more than one percent nickel (NA-383). 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 low enough yield strengths.

5.1.4.5 Effect of Temperature

The resistance to SSC of high strength, low alloy steels increases as temperature increases (TR-090, TR-S-119, GR-233), but there is no temperature above which immunity occurs. Table 5-4 shows the effect of increasing temperature on the useable YS of a number of alloys.

TABLE 5-4

SULFIDE STRESS CRACKING OF SOME HIGH STRENGTH ALLOYS

Alloy tested ^a	Yield Strength KSI	Number of samples failed/Number of samples tested							
		5% NaCl + 0.5% CH ₃ COOH + 3000 ppm H ₂ S				20% NaCl + 0.5% CH ₃ COOH + 3000 ppm H ₂ S			
		Ambient Temp.	212°F (100°C)	325°F (163°C)	425°F (218°C)	Ambient Temp.	212°F (163°C)	325°F (163°C)	425°F (218°C)
4118	120	1/1	-	-	-	-	-	-	-
	108	1/2	-	-	-	-	-	-	-
	95	0/3	-	-	-	-	-	-	-
4123 ^b	131	-	0/1	-	-	2/2	-	0/1	-
	123	-	-	-	-	1/1	-	-	-
	119.5	-	-	-	-	0/1	-	-	-
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	-	-	-	-	-	-	-
4130 (VLS) ^c	145	-	-	-	-	1/1	-	-	-
	138	-	-	-	-	1/1	-	-	-
	136	-	0/1	-	-	0/1	-	-	-
	128	-	-	-	-	0/1	-	0/1	-
	123	-	-	-	-	0/1	-	-	-
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 ^b	136.5	0/1	-	-	-	1/1	-	-	0/1
	116	-	-	-	-	0/1	-	-	-
Armco V1313 ^b	143	1/1	-	-	-	2/2	-	-	1/1
	125.5	-	-	-	-	0/1	-	0/1	-
2 Cr - 1.0 Mo	130	2/2	-	-	-	-	-	-	-
	118	1/1	-	-	-	-	-	-	-
	105	0/4	-	-	-	0/1	-	-	-
3 Cr - 1.0 Mo	154	1/1	-	-	-	-	-	-	-
	130	1/1	-	-	-	-	-	-	-
	115	1/1	-	-	-	-	-	-	-
	100	0/2	-	-	-	-	-	-	-
Type 301	160	-	-	0/1	-	-	-	-	-
Type 304	40	-	-	0/1	-	-	-	-	-
	130	-	-	0/1	-	-	-	-	-
Type 310	30	-	-	0/1	-	-	-	-	-
	70	-	-	0/1	-	-	-	-	-
A-286	190	-	0/1	1/1	-	-	-	-	3/4
	165	-	-	0/1	-	-	-	-	1/1
	135	-	-	-	-	-	-	-	0/2
K-Monel	170	0/1	-	-	-	-	-	-	0/1
	140	-	0/1	-	0/2	-	-	-	0/2
MP35N	220	0/1	-	-	0/1	-	-	-	0/2

^aSpecimens stressed 90-100% Y.S. and exposed for 30 days unless otherwise indicated.

^bexposed for ten days

^cSpecial very low sulfur heat.

Reference: TR-090

5.1.4.6 Effect of pH

Sulfide stress cracking 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 (TR-S-119).

5.1.4.7 Effect of Chloride, Moisture, and Oxygen

Chloride ions are not required for SSC (BA-563, TR-S-119), but they increase the severity of SSC in steels containing chromium. Little difference in SSC susceptibility was observed in H₂S-saturated chloride-free solutions, 30,000 ppm-chloride solutions, and 120,000 ppm-chloride solutions (TR-S-119). Whether chloride affects SSC resistance at low H₂S concentrations has not been determined.

Laboratory tests (SM-A-184, FR-233) and Wairakei field data (MA-682) confirmed that liquid water is required for SSC. Dry steam containing H₂S does not appear to be active, but SSC may occur at any location where this steam condenses.

Oxygen has a negligible effect on SSC.

5.1.5 Hydrogen Blistering of Mild Steels

Hydrogen blistering occurs in low strength steels exposed to aqueous solutions containing H₂S and has been a problem at the Wairakei geothermal plant (MA-682).

In short-term laboratory tests, H₂S partial pressures of about 0.02 psia (~60 ppm in solution) were required for hydrogen blistering of iron (GR-A-330). In long-term tests

(greater than 200 days) of cold rolled 1036 steel, 1.0 ppm H₂S in solution caused blistering while 0.1 ppm did not (HU-200).

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 of the H⁺-H₂ trapped in a void is believed to be on the order of 10⁵ atmospheres, enough to rupture any known engineering material (FO-118).

5.2 Stainless Steels

The uniform corrosion rate of most stainless steels is low in geothermal fluids, but many are subject to the more serious forms of corrosion: pitting, crevice corrosion, stress corrosion cracking, sulfide stress cracking, intergranular corrosion, and corrosion fatigue. Stainless steels have been used in geothermal environments, but care must be taken in their selection and application.

5.2.1 General Guidelines for Use of Stainless Steels

Aeration - Many stainless steels which could perform well in oxygen-free geothermal environments can be subject to severe pitting and crevice corrosion in the presence of small quantities of oxygen. Stress corrosion cracking 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 outage conditions can continue to grow once normal operation is resumed. Special care should be taken during plant commissioning due to 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 components should be drained and rinsed during plant shutdown. Resistance to erosion-corrosion is more closely related to general 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 application of stainless steels. Sensitization to intergranular corrosion by welding is discussed in Section 5.2.6. Physically poor welds may have crevices that are susceptible to crevice corrosion. Stress corrosion cracking 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 stress corrosion cracking conditions. Flange leaks leading to conditions in which geothermal fluid concentrates and dries under insulation can be dangerous. Non-porous gaskets are required to guard against cracking at flanges.

5.2.2 Corrosion Resistance of Major Classes of Stainless Steels

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 (MI-305). 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 stress corrosion cracking 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 general corrosion, but is more susceptible to stress corrosion cracking than the nickel-free alloy..

Austenitic Stainless Steels - Susceptibility to stress corrosion cracking may limit the use of austenitic stainless steels in geothermal liquids (see Section 5.2.4).

Lower alloy austenitic alloys are also susceptible to pitting and crevice corrosion. Type 304 generally has the lowest resistance; the addition of molybdenum significantly improved resistance. Type 316 with 2% Mo has much better resistance to pitting

and crevice corrosion than Type 304, but it is susceptible to corrosion in geothermal fluids, especially to crevice corrosion.

Type 317 with 4% molybdenum has significantly better corrosion resistance to localized corrosion and SCC than either 304 or 316. Further testing of Type 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 from 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.

5.2.3 Pitting and Crevice Corrosion of Stainless Steels

Pitting and crevice corrosion are the main problems for stainless steels which are resistant to 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. While the detailed mechanism of initiation may be different for pitting and crevice corrosion, environmental effects are similar in geothermal systems.

The pitting potentials (see Section 5.1.2) of stainless steels are generally much more noble (positive) than plain steels, and they should, therefore, be more resistant to localized attack. However, the corrosion potentials of stainless steels are also more noble, and it is the difference between the two which is important (Section 5.1.2). Corrosion potentials of passive stainless steels can be made more noble by small quantities of oxidizing agents resulting in rapid localized attack.

5.2.3.1 Effect of Chloride

Stainless steels become more susceptible to localized corrosion as the chloride concentration increases. This dependence is shown in Figure 5-12 for Type 304 stainless steel.

Figure 5-12. Effect of Chloride Ion Activity on Steady-State Critical Potential for Pitting, 25°C (LE-A-248)

The logarithmic dependence has been measured for other stainless steels (LE-A-338, JO-262, SU-A-132). Chloride dependence data are not available at geothermal temperatures.

5.2.3.2 Effect of pH

According to low temperature work, 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 200°C show a slight noble shift in pitting potential as the pH (measured at room temperature) was increased from 5.3 to 7 (SY-028). The corrosion potentials also shifted in the noble direction by about the same amount so there is actually little change in pitting tendency.

5.2.3.3 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 100°C. 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 150° to 250°C indicate that resistance to pitting may increase with increasing temperature in this range. Morphology of pit growth changes at elevated temperatures where the trend is to the formation of a larger number of smaller pits.

Examples of pitting and corrosion potential behavior at high temperatures in 4M NaCl are shown in Figure 5-13 (PO-230).

Figure 5-13. Pitting Potentials and Corrosion Potentials of Types 304 and 316 Stainless Steel in 4 M NaCl as a Function of Temperature (PO-230)

The region near 100°C 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 Type 304 and Type 316, and pitting or especially crevice corrosion could occur in the presence of small amounts of oxidizing agents. Similar increases occur in pitting potential for metals for 100° to 225°C in pH 9 solutions with low chloride concentrations (SP-104, ST-566). The decrease in pitting tendency at high temperatures shows that materials should be tested near the temperature at which they are to be used even if it is lower than the wellhead temperature.

Pitting kinetics have been studied over a limited temperature range (25°-50°C) for 18Cr-12Ni-2Mo-Ti in 0.1N H₂SO₄ + 0.5M NaCl at constant potentials. The number of pits increases with increasing temperature (SZ-A-022). 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.

5.2.3.4 Effects of Other Species

Stainless steels are generally resistant to corrosive attack by contaminated seawater containing H₂S and NH₃ (GE-117). Stagnant conditions should be avoided. H₂S may cause pitting of 316 in acidic solutions by retarding the formation of passive films and causing localized attack in regions of low pH (IJ-A-003).

No direct evidence for the effect of CO₂ on the pitting of stainless steels was found in the literature. High concentrations of H₂CO₃ 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 CO_2 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 Type 304 at 25°C depends on chloride concentration. Approximately $0.08\text{M SO}_4^{=}$ is needed for 0.1M Cl^- . Equal molar concentrations of Cl^- and $\text{SO}_4^{=}$ are rarely found in geothermal fluids.

5.2.3.5 Effect of Cr and Mo on Pitting and Crevice Corrosion

The pitting and crevice corrosion resistance of stainless steels is strongly dependent on their Cr and Mo contents. These effects were explored in a program to develop ferritic stainless steel condenser tubes for use in multi-stage flash evaporation desalination plants (PE-268). Pitting potentials by the scratch method were determined in deaerated artificial sea water at 90°C and pH 7.2.

Results are shown in Figure 5-14 for critical pitting potential as a function of (Cr + Mo) added (PE-268). The strong influence of Mo addition is apparent. Results for commercial alloys containing nickel show that their resistance is due primarily to their (Cr + Mo) content and not to Ni content. Some beneficial effects of (Si + Ni) addition were noted.

Crevice corrosion results in aerated synthetic sea water at 121°C are given in Figure 5-15. 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 2-3% Mo is needed

Figure 5-14. Comparison of the Critical Pitting Potentials of Fe-Cr-Mo Alloys with Several Commercial Alloys in De-aerated Synthetic Seawater at 90°C, pH = 7.2±0.2 (PE-268)

Figure 5-15. Relationship Between the Critical Pitting Potentials (E_c^{scr} Measured in Deaerated Synthetic Seawater at 90°C , $\text{pH} = 7.2 \pm 0.2$) of Fe-Cr-Mo Based Alloys and Their Resistance to Crevice Attack After a 14-Day Exposure to Synthetic Seawater at 121°C and ~ 60 ppm Oxygen. The Numbers Associated with Individual Points Indicate the Weight Losses Expressed as $\text{gms} \times 10^{-4}$ After the 121°C Exposure for Samples with Initial Weights of ~ 1 gm (PE-268)

for good crevice corrosion resistance regardless of alloy system (SE-A-133).

5.2.4 Stress Corrosion Cracking of Stainless Steels

Stress corrosion cracking (SCC) promoted by chloride ion is a severe threat in geothermal systems; austenitic steels are the most vulnerable.

Austenitic stainless steels are susceptible to SCC in hot chloride solutions. Since SCC is a catastrophic type of failure, the use of austenitics in geothermal streams requires careful evaluation. 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 SCC than are austenitic stainlesses. Some are susceptible to sulfide stress cracking or cathodic hydrogen embrittlement. However, the older alloys, (i.e., AISI Types 409, 430, 434, and 440), are much more susceptible to pitting and crevice corrosion. New alloys have been developed with much better resistance to pitting and crevice corrosion, but these alloys are not always immune to SCC (NE-207, GE-119, ST-A-570).

The resistance of precipitation hardened stainless steels to SCC in boiling MgCl_2 varies. PH 13-8 Mo was resistant for 15 days while 17-4 PH and 15-5 PH failed in less than one day.

5.2.4.1 Effect of Chloride, Oxygen, and pH

It is well established that the severity of SCC increases with increasing chloride concentration. The threshold chloride concentration may be about 5 ppm (NE-207).

Only trace amounts of oxygen (less than 100 ppb) are required for SCC of some austenitic steels (NE-207). 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 Fe^{+3} satisfy this requirement. Figure 5-16 presents the effect of increasing chloride concentration at two dissolved oxygen concentrations. In more concentrated chloride solutions (>1000 ppm NaCl), changes in oxygen concentrations have little effect on SCC resistance. In dilute chloride solutions (<100 ppm NaCl), small changes in oxygen concentration have a significant effect on susceptibility to SCC.

Figure 5-16. Effect of Chloride and Oxygen on Time to Cracking Type 304 Stainless Steel Wire Held at Constant Load in Single Phase Aqueous Environment (GO-233)

In the range normally found in geothermal environments, bulk pH is not a major factor. Cracking is more rapid and numerous in the pH 1.2 to 2.5 range (BA-557).

5.2.4.2 Effect of Temperature

Severity of cracking increases with increasing temperature (NE-207). For any given concentration of chloride, oxygen, and pH, a "lower critical temperature" exists below which SCC does not occur. This is illustrated for AISI Type 304 in Figure 5-17.

Figure 5-17. Effect of pH, Chloride Content, and Temperature on the Stress Corrosion Cracking of Type 304 Stainless Steel Under Residual Weld Stresses. As-welded Tube Specimens; NaCl Dissolved in H₂O Under Air; Exposure Time up to 8000 Hours (GO-233).

Similar behavior has been observed for other austenitic stainless steels (LA-A-338), but there are not enough data to construct figures similar to Figure 5-17. From a design standpoint, the phenomenon of a lower critical temperature means that the more resistant austenitic alloys (such as Type 317 with 4.2% Mo or USS 18-18-2 with 2% Si) should be tested in low temperature streams even if previous tests indicate they are not suitable for exposure to wellhead fluids.

5.2.4.3 Effect of Stress

Stress is required for SCC, but there is no evident lower critical stress. Time to fracture decreases sharply at stress at or above the yield point (HI-191, HO-348). 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 (LA-A-338). Austenitic stainless steels should be fully annealed.

5.2.4.4 Effect of Alloy Composition

Nickel is the constituent having the major effect on susceptibility to SCC in chloride solutions. Immunity from chloride stress cracking is not normally obtained unless the nickel content is less than 1% or greater than 45% (WA-347, LA-A-338). All AISI austenitics are susceptible to SCC under the severe test conditions of boiling MgCl_2 , but increasing nickel content above 10% gives some increase in resistance.

Additions of molybdenum improve resistance to SCC. In boiling MgCl_2 , austenitic 18Cr-8Ni-3Mo was more resistant than molybdenum-free 18Cr-8Ni (HI-191). Special Type 317 steel with 4.2% molybdenum is superior to Type 316 in resistance to SCC and local corrosion in aerated and deaerated chloride solutions (3000 and 30,000 ppm Cl^-) over a wide range of pH (LI-A-230). This same alloy was immune to SCC for 1464 hours (test duration) in boiling, acidified 25% NaCl (pH 1.5), while Type 304 failed in 10 hours. The increased molybdenum content, and not the slightly higher chromium and nickel content, was responsible for the superiority (LI-A-230, DU-153).

Silicon addition also improved resistance to SCC; USS 18Cr-18Ni-2Si is 10 to 100 times more resistant than Type 304 in boiling MgCl_2 and has a good process industry record in hot chloride systems (LO-A-240). Type 310 containing 1.5% silicon showed no SCC and no reaction to sulfides in nonacid chloride solutions below 450°C . Type 310 tends to tear and is difficult to machine.

Type 314 contains more chromium and nickel than Type 317 and has 2-3% molybdenum and 1.5-3% 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 1% nickel are susceptible to SCC in MgCl_2 although some resist cracking in the wick test and in boiling 20% NaCl (NE-207, ST-A-570, GE-119). The addition of more than 0.5% copper is detrimental to ferritic steels (GO-233). The 26Cr-1Mo, 29Cr-4Mo, and 29Cr-4Mo-2Ni alloys depend on low interstitial concentrations of carbon or nitrogen to resist SCC in heat affected zones. 26-1 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 (ST-A-570).

5.2.4.5 Comment on Laboratory Test Methods

The oldest test for chloride SCC is the boiling MgCl_2 test. This is a severe environment, and it is often difficult to relate results from this test with results from less severe

environments (NE-207). The boiling LiCl test is usable at higher pH's, does not form an insoluble hydroxide, has better chemical purity, and cracks Type 304 in an identical manner at similar times (WI-A-317). The wick test (DA-268) is considered by many to be the most realistic test for marine and desalination environments. A dilute NaCl solution is "wicked up" onto an electrically heated U-bend where evaporation concentrated the NaCl. This test is thought to be especially good where chloride solutions are flashed.

5.2.5 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.

5.2.5.1 Austenitic Stainless Steels

Intergranular corrosion occurs in austenitic stainless steels when they are sensitized [i.e., heated in the 510-790°C range] (FO-118). The range may extend to 900°C (CI-A-027). When stainless steels are welded, a zone called the heat affected zone or 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 1065°C to 1120°C, and water quenched). 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 (FO-118). HAZ intergranular corrosion can be controlled by lowering the carbon content below 0.03%. These 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 (FO-118).

5.2.5.2 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 930°C. Addition of 2% nickel raises the sensitization temperature to 1040°C. Molybdenum has little effect.

Quenching prevents intergranular corrosion. Weld decay of 1-2% nickel alloys can be prevented by one-hour treatment at 820°C followed by water quenching. Lower nickel alloys require four hours at 820°C (BO-A-323).

Addition of more than 0.47% titanium to 18Cr-2Mo alloys completely prevents intergranular corrosion in the Strauss test after all sensitizing treatments. Alloys containing more than 1.2% titanium are embrittled after annealing from 820°C. This embrittlement can be removed by water quenching from 1040°C. Additions of 0.61% niobium prevent intergranular corrosion of post-weld specimens in the Strauss test (BO-A-323).

5.2.6 Sulfide Stress Cracking of Stainless Steels

Austenitic stainless steels are fcc and are generally considered to be immune to SSC. AISI Types 301, 304, and 310, at fully softened and partially work hardened conditions resisted SSC at 162°C (TR-090).

Martensitic stainless steels are very susceptible to SSC at ambient temperatures (FR-233). AISI Type 410 and Carpenter Custom 450 are susceptible at hardnesses well below Rc 22. A 13Cr martensitic steel at the Wairakei geothermal plant resisted SCC below Rc 10 (MA-672). A special 12Cr alloy has been described that can be used in sulfide environments at Rc 27 or below (NA-383).

AISI Types 405 and 430 ferritic stainless steels in annealed condition with Rc $\leq$ 22 are suitable for H₂S service at ambient temperatures (NA-383).

AM-350, AM-355, and 18Ni maraging steels offer no improvement over low alloy steels with regard to SSC resistance (HU-200). 17-4 PH, 15-5 PH, and PH 13-8Mo are susceptible to SSC at stresses between 30% and 50% of yield (WA-347). A-286 was not susceptible at 98% of yield strength at room temperature. The resistance of A-286 decreases as temperature increases (TR-090). Whether or not this effect is common to all precipitation hardening steels is not known.

5.3 Titanium and Titanium Alloys

Titanium and its alloys have given good results in all but the most extreme environments when tested for geothermal applications. Titanium was used successfully for hydrogen and oil coolers exposed to aerated cooling water/condensate at the

Cerro Prieto geothermal facility (GE-119). Two other heat exchanger materials had failed in this environment.

5.3.1 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 with corrosion rates of 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 (GE-117).

5.3.2 Pitting and Crevice Corrosion of Titanium

No significant local corrosion should occur in environments with less than 10% chloride. Desalination and chemical process industry experience shows that crevice corrosion in tight crevices may be a problem in high-temperature, high-chloride solutions 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.

5.3.2.1 Effect of Chloride and Temperature

The interaction of chloride concentration and temperature is given in Figure 5-18.

Figure 5-18. Anticipated Corrosion Performance of Unalloyed Titanium (ASTM Grade 2) in Chloride Brines and Under NaCl Solid Salt Deposits (Based on data in GE-117)

The critical temperature below which localized attack does not initiate at any chloride concentration in neutral NaCl solutions is about 64°C. Below 10% chloride, resistance extends above 250°C. Localized corrosion can still occur at sites of local high temperature or local solution concentration (e.g., where flashing or evaporation occurs) even though the bulk solution will not cause attack.

Oxygen is required for good local corrosion resistance of titanium in hot, concentrated chloride solutions. Titanium crevices exposed to deaerated Salton Sea fluid at 232°C underwent severe pitting and moderate crevice corrosion; samples in aerated (100 ppm O₂) fluid were resistant to local corrosion (NE-302).

5.3.2.2 Effect of pH

In the pH range normally found in geothermal fluids, decreasing pH lowers the usable ceiling temperature. Figure 5-19 illustrates the effect of pH on crevice attack of pure titanium. Much better results are obtainable with small alloy additions.

Figure 5-19. Effect of Temperature and pH on Crevice Corrosion of Unalloyed Titanium (GR.2) in Saturated NaCl Brine (FR-S-267)

5.3.2.3 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 (TA-134, SH-333) but may cost 70% more than titanium. TiCode-12 has almost equal resistance (CO-598) and may cost only about 20% 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 260°C in the pH range anticipated in geothermal streams.

Figure 5-20 shows the effect of pH on crevice corrosion of TiCode-12. These results should be compared with those for pure titanium in Figure 5-19.

Figure 5-20. Effect of Temperature and pH on Crevice Corrosion of TiCode-12 (Gr. 12) in Saturated NaCl Brine (FR-S-267)

5.3.3 Galvanic Coupling and Other Precautions

Titanium is cathodic to most other metals in saline environments. If the titanium area is large compared to the other 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 (CO-598). Some Ti-Ni alloys are susceptible to hydrogen embrittlement in desalination service (GE-117).

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-Type 316 crevices are also resistant to crevice attack. Tight titanium-to-Teflon crevices are much more susceptible to attack than titanium-to-titanium crevices.

Iron particles left in scratches on titanium can initiate pits (CO-598). 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. $MgCl_2$ inclusions in powder metallurgy titanium serve as nucleation sites for pitting. A low magnesium alloy will give better service than one containing a few ppm $MgCl_2$ (BO-270).

5.3.4 Stress Corrosion Cracking of Titanium Based Alloys

Commercial titanium alloys are not considered to be susceptible to cracking in 3% NaCl solutions at ambient temperatures. However, precracked specimens of many fail rapidly in 3% NaCl solutions. This behavior indicates that the 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 (BO-A-314). SCC should therefore not be a major problem, provided that components are not pre-cracked 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 specimen (BO-A-314). Table 5-5 lists resistant alloys and alloys which are sensitive in the precracked condition.

Only chloride, bromide, or iodide ions are effective as cracking agents. Fluoride, hydroxide, sulfide, sulfate, nitrite, nitrate, perchlorate, cyanide, and thiocyanate have no effect. Different alkali or alkaline earth cations have little effect on cracking (BE-A-501).

Both hydrogen embrittlement and active path dissolution are involved in the mechanism of crack propagation (BO-A-314, MA-705, CO-598).

TABLE 5-5

SENSITIVITY OF TITANIUM ALLOYS TO CRACK PROPAGATION

<u>Titanium Alloys Which Undergo Accelerated Crack Propagation in Ambient 3 wt. % NaCl</u>	<u>Titanium Alloys Which Do Not Undergo Accelerated Crack Propagation in Ambient 3 wt. % NaCl</u>
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-7Al-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-7Al-3Cb (as received and beta annealed)	
Ti-7Al-3Mo	
Ti-7Al-3Cb-2Sn	
Ti-8Al-1Mo-1V	
Ti-8Al-3Cb-2Sn	

Reference: BO-A-314

5.4 Nickel Based Alloys

High nickel alloys are frequently used to combat severe corrosion problems. The Ni-Cr-Mo alloys appear to be the most applicable to high temperature geothermal fluids. 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 will have limited usefulness in geothermal streams containing even trace quantities of H_2S .

5.4.1 General Corrosion Resistance of Ni-Cr-Mo Alloys

The higher ranked members of this class of alloys such as Inconel 625 and Hastelloy C-276 have given excellent resistance to corrosion in geothermal systems. These two alloys can normally tolerate very high flow rates and occasional aeration. Effects of alloy composition are complex, but high molybdenum content is important for best corrosion resistance. Some pitting and crevice corrosion has 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 1% NaCl, pH 5, 10 ppm H_2S solution at 250°C (SH-381). In the same tests Hastelloy C-276 and Inconel 625 corroded at only 0.2 mpy.

5.4.2 Stress Corrosion Cracking of Nickel Based Alloys

Nickel-based alloys contain more than 45% nickel and should therefore have good resistance to SCC. If interstitial carbon is not kept low (<0.004%), these molybdenum-bearing nickel based alloys may be susceptible to SCC in heat affected zones from welds (ST-A-563).

The following alloys were resistant in the unsensitized state to boiling MgCl_2 for 15 days: Inconel 625, Inconel X-750, Inconel 825, Monel K-500, Hastelloy C, Hastelloy C-276, and Hastelloy C-4 (WA-347, ST-A-563). Other nickel-based alloys may also be resistant to SCC.

5.4.3 Sulfide Stress Cracking and Hydrogen Embrittlement

Monel (Rb 63) and K-Monel (Rc 37) were completely resistant to sulfide stress cracking during the standard NACE test at ambient temperatures (HU-200, VO-067). Monel K-500 (Rc 36) was resistant at 98% YS. Inconel 625 (Rc 20 and 39), Inconel X-750 (Rc 37), and Inconel 718 (Rc 34) were resistant at 98% YS. Hastelloy C-276 (Rc 41) and Hastelloy G (Rc 35) were also resistant (WA-347).

Hastelloys G and C-276, and Inconel 625 are susceptible to hydrogen embrittlement when coupled to steel. In the presence of dissolved oxygen, no H_2S is required; but H_2S reduced the time-to-failure (KA-A-301). The effect of coupling to steel has not been documented for other nickel-based alloys.

5.4.4 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%, a molybdenum-rich carbide (M_6C) forms in the temperature range 649°C - 1204°C , depleting molybdenum in the grain boundaries. The molybdenum depleted zones are attacked by reducing acids (ST-A-563) and could be affected by geothermal fluids.

5.5 Copper Based Alloys

The use of copper alloys in geothermal fluids is severely limited by the relatively high concentrations of sulfide found in most sources. The Raft River KGRA, with a low sulfide concentration of 0.1 ppm, appears to be an exceptional case. Even in this fluid the performance of copper-nickel alloys (Monel 400, 70Cu/30Ni, and 90Cu/10Ni) was very poor. Dealloying of some copper alloys was observed. However, some nickel-free brasses and bronzes gave acceptable performance (MI-305).

The cracking of some copper-based alloys, especially α brasses, exposed to ammonia or ammonia derivatives is well known under the name "season cracking" (FO-118). When cracking is caused by ammonia species, cupric complexes $\{\text{Cu}(\text{NH}_3)_n^{+2}\}$ are required at the metal surface in significant quantity. An adsorbed layer of O_2 or a thin oxide film also seems necessary (BO-A-313, PU-A-068). Unless the NH_3 or NH_4^+ 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 < 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 > 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% Ni. Resistance increases sharply above ~30% Ni. The resistance of

Cu-Al alloys is lowest between 1 and 2% Al and increases sharply above ~5% Al (PU-A-068).

SCC of admiralty brass under anodic polarization but in the absence of ammonia has been observed (KA-A-302).

5.6 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.

5.6.1 Cobalt Alloys

Cobalt alloys may find application in services requiring high strength combined with resistance to sulfide stress cracking and in services requiring wear resistance.

MP35N resists sulfide stress cracking 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 (AU-064). No pitting or crevice corrosion of Haynes 6B, another wear-resistant alloy, was observed in Raft River field tests.

Cobalt-base alloys generally have good resistance to sulfide stress cracking. MP35N (Rc 51), MP159 (Rc 46), Haynes Alloy 25 (Rc 47), were resistant at 89% YS (WA-347). Stellites 1 and 6 were also resistant (FR-233). However, MP35N may be susceptible to sulfide stress cracking when coupled to a more active metal such as iron (TR-090). The effect of galvanic

coupling on the SSC resistance of other cobalt alloys is not known.

Alloys MP35N and MP159 are resistant to stress corrosion cracking in boiling MgCl_2 (WA-347). Data about other cobalt alloys are lacking.

5.6.2 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.

5.6.3 Aluminum Alloys

Aluminum alloys have not shown good resistance in tests conducted in direct contact with geothermal fluids. 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.

Rapid pitting of aluminum heat exchanger tubes and test coupons was observed in condensate and cooling water at Cerro Prieto, Mexico (GE-119).

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 H_2S emissions. Fluoropolymer-coated aluminum exterior sliding panels are used in new housings at The Geysers power plant.

5.7 Condensate

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 CO_2 , H_2S , and NH_3 which are absorbed by the condensate,
- pH of the condensate resulting from absorption of the above gases,
- 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 CO_2 and H_2S absorbed relative to basic NH_3 . The pH in turn determines the corrosivity of dissolved H_2S and CO_2 in contact with mild steels. For most sources the NH_3 is low compared to CO_2 and H_2S and the condensate pH will be fairly low.

Previous sections can be consulted for discussion of effects of pH, H_2S , CO_2 , NH_3 , and oxygen. Corrosion problems have occurred in the condensate systems of several operating geothermal plants (see Appendix A). Although condensate streams have relatively low chloride concentrations, their potential corrosivity should not be underestimated.

Even with very efficient steam separation the chloride content of the condensate can be high enough to cause problems.

For example, assuming 25% flashing of a wellhead liquid containing 1% chloride and 0.05% 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 25°C (SZ-020).

If the condensate is aerated and temperature is greater than 60° to 80°C, stress corrosion cracking of austenitic stainless steels could occur at this chloride concentration.

5.8 Steam from Liquid-Dominated Geothermal Sources

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.

- 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 separation and scrubbing efficiency, corrosivity may depend on the chloride content and corrosivity of the liquid stream.
- Areas where local condensation may occur are subject to attack by low pH condensate containing H_2S , CO_2 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.

5.8.1 General Corrosion in Geothermal Steam

Corrosion rates of low alloy steels in steam flow from several geothermal sources are summarized in Table 5-6. Uniform corrosion rates in oxygen-free steam are generally low except in separated Salton Sea steam. The reason for high corrosion rates in this 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 and not just the diluted concentration of the condensate. The low chloride contents quoted for the steam phase may therefore be misleading.

Steam scrubbing can reduce the number of drops but not the chloride concentration of each drop; little reduction in corrosion rate after steam scrubbing was found. It is also noteworthy that the localized corrosion susceptibility of resistant alloys is similar in Salton Sea wellhead liquid, separated steam, and scrubbed steam.

5.8.2 Corrosion Fatigue

Although corrosion fatigue occurs in both steam and liquid media, this failure mode is discussed in this section because turbines operating in geothermal steam are subject to both environments. Turbines are the most important components in a geothermal plant that will be subject to corrosion fatigue.

Metals under cyclic loading fail at stresses far below those characterizing their normal mechanical properties. When this phenomenon occurs in "inert" environments, (i.e. air),

TABLE 5-6

CORROSION OF PLAIN AND LOW ALLOY STEELS IN STEAM

FROM LIQUID-DOMINATED SOURCES

Site/Steam Source	Temp (°C)	pH ¹ (condensate)	Chloride (condensate) (ppm)	H ₂ S ppm (wt)	CO ₂ ppm (wt)	Moisture	Uniform Corrosion	Local Corrosion ²	Steel Type
<u>East Mesa</u>									
First Flash	-	5.2	3000-5000 ³	-	-	-	2.1	C	AISI 1020
	-	5.2	3000-5000 ³	-	-	-	1.3	C	AISI 4130
Second Flash	-	5.7	200-500 ²	-	-	-	3.1	C	AISI 1020
	-	5.7	200-500 ²	-	-	-	2.5	C	AISI 4130
<u>Salton Sea</u>									
First Flash	190 ⁴	6.15	120	10-20	3,900-6,600	~0.1% ⁵	26	P	AISI 1020
	190 ⁴	6.15	120	10-20	3,900-6,600	~0.1% ⁵	7.7	P	AISI 4130
Scrubbed First Flash	~190 ⁴	-	-	-	-	-	21-40	P	AISI 1020
	~190 ⁴	-	-	-	-	-	18	P	AISI 4130
Second Flash	~178	6.10	50	-	-	<0.1% ⁵	25	P	AISI 1020
	~178	6.10	50	-	-	<0.1% ⁵	8.2	P	AISI 4130
Scrubbed Second Flash	~178 ⁴	-	-	-	-	-	18-27	P	AISI 1020
	~178 ⁴	-	-	-	-	-	25	P	AISI 4130
<u>Cerro Prieto, Mex</u>									
Single Flash	150	-	13	2,000	19,500	<1%	1.6	N	1 Cr-1.3 Mo-0.25V
	150	-	13	2,000	19,500	<1%	0.7	P	3.5 Ni-1.75 Cr- 0.4 Mo-0.1V
	150	-	13	2,000	19,500	<1%	1.6	N	ASTM A285
<u>Wairakei, N.Z.</u>									
Single Flash	190	-	-	-	-	<1%	<1.0	-	Carbon steels
	190	-	-	-	-	<1%	<1.0	-	Carbon Mn steels
	140	-	nil	140	1,500	<1%	6	-	Carbon steels
	140	-	nil	140	1,500	<1%	2	-	Carbon Mn steels
	140-160	-	-	-	-	10%	1.0-10	-	Carbon steels
	140-160	-	-	-	-	10%	1.0-10	-	Carbon Mn steels
	115	-	-	-	-	10%	5	-	Carbon steels
	115	-	-	-	-	10%	4	-	Carbon Mn steels

¹Measured near ambient temperature²P - pitting corrosion

C - crevice corrosion

N - none detected

³Data distorted by control valve problems⁴Calculated⁵Calculated from chloride concentration in condensate.

Pitting and crevice corrosion rates are given in Section 4.

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, and below this stress there will be no failure, no matter how long the test. This is the "fatigue limit" (GI-122, WE-317).

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 is the greatest unit stress which may be applied under given conditions of stress, rate of stress application, temperature, and corrosive environment without causing it to fail in a given number of cycles of stress (WE-317). 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.

5.8.2.1 Low Alloy Steels

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 [$R_b \sim 64$] was 27.8% while 3.5Ni-1.75Cr-0.4Mo-0.1V [$R_b \sim 68$] showed a 38.6% reduction of FEL. These specimens were not under cyclic stress during exposure. Cyclic loading during exposure would have caused greater loss of endurance.

Some of the considerations for low alloy steels in contact with corrosive liquids are discussed below in relation to corrosion fatigue.

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. salt water), are practically independent of the chemical composition of the steel (ME-A-243).

A series of corrosion fatigue tests were done in a solution containing 34,400 ppm Cl solution with additions of CO_2 , H_2S and O_2 . AISI 1035 specimens were stressed 10^7 cycles at 10 Hz (ME-A-243). Chloride had no significant effect on the fatigue endurance of low alloy steels. In a neutral, air-free (<0.1 ppm O_2) solution, the fatigue endurance limit (compared to the fatigue endurance limit in air) increased slightly.

Addition of 3000 ppm H_2S to the chloride solution lowered the pH to 4.5. The endurance limit decreased 20%, and cracking and hydrogen blistering occurred. The effect of H_2S on harder materials may be much more severe. These materials will be cold-worked under cyclic stress and may become susceptible to sulfide stress cracking as well as corrosion fatigue.

Addition of 700-800 ppm free CO_2 and 250-300 ppm HCO_3^- to the chloride solution reduced the pH to 5.5 and reduced the fatigue endurance limit 41%. Many cracks were observed. Although CO_2 does not cause stress corrosion cracking, it appears to be an effective cracking agent when combined with cyclic stress.

The combined effect of CO_2 and H_2S is worse than the sum of their actions. In a chloride solution containing 700-800 ppm free CO_2 and 60-70 ppm H_2S , the fatigue endurance limit decreased 62%. Both pitting and surface cracking were observed.

The addition of less than 10 ppm O₂ drastically reduced the fatigue endurance limit in the chloride solution (65% reduction). Addition of 3 ppm O₂ doubled the reduction in endurance limit in the chloride/H₂S solution, but caused little if any increase in damage in the chloride/CO₂ solution.

5.8.2.2 Stainless Steels

Results from Cerro Prieto (Table 5-7) indicate that increasing chromium or adding molybdenum and/or tungsten reduces the decrease of fatigue endurance limit (FEL).

TABLE 5-7
REDUCTION IN FATIGUE ENDURANCE LIMIT AT
CERRO PRIETO AFTER 150 DAYS EXPOSURE

<u>Alloy</u>	<u>Hardness</u> <u>(approximate)</u>	<u>Reduction in</u> <u>FEL %</u>
12 Cr	R _b 57	18.5
12 Cr-1Mo-1W	R _b 74	14.6
12 Cr-0.2Al	R _b 49	18.8
15Cr-1.7Mo	R _b 41	11.7

Reference: GE-119

Type 616, Type 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 (TO-089).

In neither the tests at Cerro Prieto nor Baca were the samples 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 H_2S , while nickel is more effective against H_2S (WE-317). Best results are obtained with a combination of chromium and nickel (GI-122). Molybdenum is also beneficial (WE-317).

5.8.3 Exfoliation

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 H_2S . 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 encountered at the Cerro Prieto geothermal plant. Measures taken to prevent turbine damage are given in Appendix A.2.4.2.

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 10-15 years old. This experience accentuates the need for close monitoring and frequent inspection of geothermal turbines.

The search for construction materials in geothermal environments has concentrated primarily on metallic materials, but applications of nonmetallic materials are receiving increasing attention. Nonmetallic materials are required in some geothermal operations such as elastomers in drilling operations. In other areas, they may be cost-effective replacements for metallic materials. Nonmetallic materials have some advantages. They are generally resistant to corrosion at conditions that may adversely affect metals and alloys, and their installation costs may be lower than for metals. However, nonmetallic materials are subject to degradation, and geothermal fluids severely test their durability. Nonmetallics are not useful in heat transfer equipment.

The performance of nonmetallic materials in geothermal environments is in the early stages of investigation, and the test results are somewhat limited. Some comparisons and trends may be found by examining the results of nonmetallics in desalination fluids and from conventional drilling technologies. Testing of nonmetallics as desalination materials has been conducted in flowing sea water up to 250°F (121°C). Although these temperatures are somewhat low for some geothermal applications, the data are useful as general guidelines.

Nonmetallic materials that may find geothermal applications are:

- 1) concrete polymer composites,
- 2) cements,
- 3) elastomers,
- 4) fiber reinforced plastic laminates,

- 5) thermoplastics,
- 6) fiber reinforced plastic and coated pipe, and
- 7) paints and coatings.

No systematic attempt has been made to identify processing steps in a geothermal facility where nonmetallics may be used.

6.1 Concrete Polymer Composites

Brookhaven National Laboratory is conducting a program to develop polymer concrete materials for geothermal applications. Polymer formulations and polymer concrete composites which can be used as materials of construction for handling geothermal brines and steam at temperatures up to 260°C (500°F) are being investigated.

Formulations with the following constituents have produced monomer systems suitable for geothermal conditions.

- 1) styrene - trimethylolpropane trimethacrylate (TMPTMA)
- 2) styrene - acrylonitrile - TMPTMA
- 3) Derakane ® - triallyl cyanurate

Acrylamide, methacrylamide, and crosslinking agents are being added to styrene - acrylonitrile formulations to determine the optimum compositions. The durability of polymer concrete is dependent upon the aggregate composition. Above 218°C, only polymer concrete materials containing mixtures of silica sand and portland cement have been resistant to geothermal brine and steam. The presence of portland cement in the aggregate greatly

enhances the durability. The evidence indicates that CaO reacts chemically with the $-CH_2$ groups in the monomers. Table 6-1 gives the compressive strength as a function of temperature for a number of polymer concretes. The results in Table 6-1 are for mortar containing fine aggregate consisting of 70 wt % silica sand and 30 wt % Type III Portland cement. This composition is representative of the material that will be used in thin-wall pipe or as a lining material. Higher strengths result if larger size aggregate is included.

TABLE 6-1
HIGH TEMPERATURE STRENGTHS OF POLYMER-IMPREGNATED MORTAR

Test Temperature °C	Compressive Strength, psi			
	A	B	C	D
21	13,889	11,782	10,069	9,487
66	14,154	10,948	10,334	7,838
150	12,154	10,222	8,427	8,102
175	13,619	13,898	8,282	8,180
204	9,475	9,786	10,453	6,600
238	11,207	9,632	10,308	6,197

Monomer Formulations:

- A. 55 wt % styrene - 36 wt % acrylonitrile - 9 wt % TMPTMA
- B. 50 wt % styrene - 33 wt % acrylonitrile - 17 wt % TMPTMA
- C. 60 wt % styrene - 40 wt % TMPTMA
- D. 70 wt % Derakane® 470 - 30 wt % triallyl cyanurate

Reference: KU-161, KU-162

The structural durability of polymer concretes has been tested both in the laboratory and field in simulated brine, flowing brine, flashed brine, and steam at temperatures up to 260°C. Laboratory data for exposure times greater than two years are available, and field tests of over 18 months have been conducted. Some of the field tests are still in progress. A

summary of the results of laboratory and field tests is given in Table 6-2.

6.2 Cements

Cements find possible applications as corrosion resistant lining materials and in well construction.

Improved cementing materials for the construction of geothermal wells are needed to increase well life expectancy. Specifications for well cementing materials are listed below:

- 1) Compressive strength, >1000 psi 24 hours after placement.
- 2) Permeability to water, <0.1 milli Darcy.
- 3) Bond strength to steel casing, >10 psi.
- 4) Stability, no significant reduction in strength or increase in permeability after prolonged exposure at 400°C (~750°F) to 25% brine solutions, flashed brine, or dry steam.
- 5) Placement ability, capable of 3 to 4 hr. retardation at expected placement temperatures.
- 6) Compatibility of the cement with drilling mud.
- 7) Non-corrosive to steel well casing.

Polymer concretes and inorganic cements such as C-S cements and phosphate bonded glass cements are being investigated as potential cementing materials.

TABLE 6-2

POLYMER CONCRETE TESTING IN GEOTHERMAL FLUIDS

<u>Location</u>	<u>Conditions</u>	<u>Duration</u>	<u>Results</u>
Laboratory	25% brine, 238°C	325 days	Some slight corrosion at corners; no previous deterioration
Laboratory	25% brine, 177°C	760 days	No deterioration
Laboratory	pH 1, HCl, 90°C	441 days	No deterioration
Laboratory	pH 1, HCl, 200°C	170 days	No deterioration in silica-portland cement aggregates; limestone aggregates cracked after 25 days
Geysers	steam, 238°C	18 months	No deterioration
Baca	flashed brine, 160°C	180 days	No deterioration
Raft River	fluid, 135°C	90 days	No deterioration
Raft River	fluid, 150°C	312 days	No deterioration
Raft River	400 ppm brine, 204°C	in progress	
East Mesa	brine, 160°C	60 days	No deterioration
Niland	brine, 220°C	in progress	

Reference: KU-161, KU-162

Corrosion resistant cements may also find applications as lining materials. Five corrosion resistant cements were tested for twelve months at 250°C, 30 psi in flowing seawater during a study of desalination materials. The results of the test are shown in Table 6-3. Only Prekrete G-8 withstood the exposure and did not degrade or break. Prekrete G-8 gave excellent service for six years in a desalination facility at Freeport, Texas.

TABLE 6-3
PERFORMANCE OF CORROSION RESISTANT CEMENTS
IN 250°F SEAWATER (12-MONTH EXPOSURE)

<u>Name</u>	<u>Type</u>	<u>Appearance</u>
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
<hr/> Reference GE-117		

6.3 Elastomers

Elastomers have applications in geothermal drilling technology. The Department of Energy is conducting research to develop elastomers for geothermal use. Five research programs are involved in various phases of the development and testing of elastomers for use in geothermal wells. The goal is to seek new materials and define tests methods for geothermal

applications. Of particular interest are packer seals and drill bit cutter cone seals. The approaches range from basic research to applied development and include synthesis of new polymers, investigation of new but available (at high cost) elastomers, modification of commonly known materials and development and evaluation of test methods.

The goals of the five research programs are described below.

- 1.) Test seals produced from new materials. A special device which simulates the environment of the cutter cone has been developed.
- 2.) Develop packer seals and a simulated test device for down-hole condition duplication. The materials used for packer seals are common hydrocarbon elastomers.
- 3.) Synthesize new quinoxaline and styrene type elastomers and investigate the modification of existing commercial materials for packer seals. Tensile properties, thermal stability and stress relaxation tests are being conducted.
- 4.) Synthesize new fluorinated elastomer systems and look at carboranesiloxane (Ucarsil) systems. These materials are being tested for thermal and hydrolytic stability, compression set, hardness and tensile properties.
- 5.) Study the feasibility and value of coating O-ring seals in an RF glow discharge apparatus.

The results of these ongoing studies are described in Appendix D.

These programs have revealed that conditions are so severe and different from those in other applications of elastomers that nearly all previous test data are of very little value. Thermal stability is usually measured in an oxidative atmosphere. The results of thermal stability tests give little indication of polymer performance under typical geothermal stresses such as reducing atmospheres and hydrolysis. Furthermore, some unpredicted reactions can take place at the extreme pressures of the well. Elastomers for geothermal uses must be investigated under appropriate test conditions.

6.4 Fiber Reinforced Laminates

Fiber reinforced plastic (FRP) laminates may be useful because of their high corrosion resistance and reasonable cost. FRP materials have not been adequately tested in geothermal systems, but an indication of their potential can be obtained from the results of testing in desalination environments (GE-117). Table 6-9 summarizes the results of exposing FRP laminates to flowing seawater at 250°F for 15 months. At high temperatures, only Bis-A epoxy systems and halogenated vinylester Derkane ® systems gave acceptable results. Testing of FRP materials in geothermal environments is required.

6.5 FRP and Coated Pipe

Nonmetallic piping materials have been tested in desalination facilities (GE-117). Glass reinforced epoxy piping systems were found to be acceptable for handling brines in the 210°F to 250°F range. Additional testing of nonmetallic pipes should be conducted for geothermal applications.

TABLE 6-4

FRP LAMINATES IN FLOWING SEAWATER AT 250°F, 30 PSIG
AFTER 15 MONTHS OF EXPOSURE

Resin Tested	Percent Retention			
	Flexural Strength	Flexural Modulus	Tensile Strength	Appearance Rating**
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	40.0
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
PPG Iso-Polyester Selectron® 5899	7	8	8	74.0
PPG Iso-Polyester Selectron® 5899	3	9	***	79.8
Freeman Ortho-Polyester Stypol® 40.2187*	5	5	***	77.4

*Higher density air bubble inclusion.

** 0 = No change.

100 = Complete failure.

***Not tested due to degradation of sample.

Reference: GE-117

6.6 Thermoplastics

Polysulfone has shown no sign of thermal distortion or change in physical properties in seawater tests at 250°F. The durability of thermoplastics in geothermal environments is unproven.

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APPENDIX A

CORROSION EXPERIENCE AT OPERATING UNITED STATES AND FOREIGN GEOTHERMAL POWER PLANTS

CORROSION EXPERIENCE AT OPERATING UNITED STATES AND FOREIGN GEOTHERMAL POWER PLANTS

Previous experience is of the utmost importance in corrosion engineering. This section summarizes the corrosion experience at Wairakei, New Zealand, Cerro Prieto, Mexico, and The Geysers in California. The first two geothermal power plants use liquid-dominated resources while The Geysers is steam-dominated. Experience from all three facilities provides valuable information that identifies potential problems and solutions. Data from Cerro Prieto are particularly valuable because it is located near several potential sites for geothermal development that have similar fluid chemistry.

A.1 CORROSION AT 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.

A.1.1 System Description

The Wairakei geothermal resource is liquid-dominated and is utilized by single flash recovery (bore flashing). Steel-cased bores 150m to 1200m deep tap geothermal fluid at temperatures up to 270°C containing CO₂ (90-8000 ppm), H₂S (3-320 ppm), NaCl and KCl (1000-2000 ppm Cl⁻), and SiO₂ (150-500 ppm) as major contaminants with many other constituents as 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 non-condensable gases

is run to waste. Steam, containing most of the non-condensables and less than one percent moisture (droplet carry-over) at 50-200 psig, passes through low pressure turbines. After the turbines, the steam (at about 40°C and 1 psia) is condensed by sprays of O₂-saturated cold water in jet condensers and removed via a barometric seal. Non-condensable gases are removed by vacuum pumps (FO-120).

A.1.2 The Wairakei Geothermal Fluid

Little detailed data are available on the composition of the geothermal fluid at Wairakei. A computer reconstruction of the composition of the fluid in the geothermal strata around Bore No. 20 is given in Table A-1. This is not the composition at the surface.

A.1.3 Corrosion Tests at Wairakei

Two studies of common engineering materials were performed jointly by the New Zealand Ministry of Works and Department of Scientific and Industrial Research. The International Nickel Company also ran a series of tests. Tables A-2, A-3, and A-4 summarize the corrosion test results.

In all three tests, the general corrosion rate was determined by the ASTM A 244 coupon method. In the tests reported in Table A-2, the stress corrosion samples were constant deformation strip specimens stressed beyond the yield point. No pitting information was presented in the source for Table A-2. In Table A-3 the stress corrosion specimens were U-bend strips stressed beyond the yield point and retained under stress with a bolt. The specimens were exposed to geothermal media intended to span the range of conditions found at the Wairakei project.

TABLE A-1
AQUIFER FLUID ADJACENT TO HOLE 20,
WAIRAKEI, NEW ZEALAND

Temperature = 246°C
Pressure = 545.3 psia
Enthalpy¹ = 455.04 Btu/lb
pH² = 6.34
CO₂ partial pressure = 11.46 psia
H₂S partial pressure = 0.13 psia

Dissolved Constituents	Concentration (mmol/kg H ₂ O)	Concentration (by weight)
Li ⁺	1.5	10 ppm
Na ⁺	38.3	880 ppm
K ⁺	4.1	160 ppm
Rb ⁺	0.025	2.1 ppm
Cs ⁺	0.014	1.9 ppm
Ca ⁺²	0.43	17 ppm
Mg ⁺²	0.0	
F ⁻	0.29	5.5 ppm
Cl ⁻	0.42	1520 ppm
Br ⁻	0.05	4.0 ppm
I ⁻	0.002	250 ppb
SO ₄ ⁻²	0.079	7.6 ppm
H ₂ BO ₃	1.74	108 ppm
H ₂ BO ₃ ⁻	0.002	120 ppb
H ₂ CO ₃ + CO ₂ aq	7.89	489 ppm ³
HCO ₃ ⁻	0.35	21 ppm
CO ₃ ⁻²	0.00001	0.6 ppb
H ₄ SiO ₄ ⁰	7.85	96.1 ppm
H ₃ SiO ₄ ⁻	0.006	600 ppb
H ₂ SiO ₄ ⁻²	0.00001	0.9 ppb
NH ₄ ⁺	0.002	36 ppb
NH ₃ aq	0.011	190 ppb
H ₂ Saq	0.25	8.5 ppm
HS ⁻	0.022	730 ppb
HF ⁰	0.050	1.00 ppm
HSO ₄ ⁻	0.0023	220 ppb
HCl ⁰	0.00006	21.8 ppb
NaCl ⁰	1.27	72.2 ppm
KCl ⁰	0.097	7.2 ppm
MgSO ₄ ⁰	0.0	
CaSO ₄ ⁰	0.025	3.4 ppm
KSO ₄ ⁻	0.015	2.03 ppm
NaSO ₄ ⁻	0.15	18 ppm
CaCO ₃	0.0002	20 ppb
MgOH ⁺	0.0	

¹Saturated water enthalpy is 458.28 Btu/lb.

²Neutral pH at 246°C is 5.6.

³As H₂CO₃.

Reference: TR-054

TABLE A-2a

MATERIALS TESTS AT WAIRAKEI, NEW ZEALAND: GENERAL CORROSION

		General Corrosion (mpy)							
Equivalent Specification ¹		Bore Water 240°C 63-68 Days	Bore Water 50-100°C 54-95 Days	Separated Water 125°C, 80 psig 155 Days	Separated Steam 193°C, 180 psig <1% Moisture, 144 Days	Separated Steam 142-162°C, 40-8- psig 10% Moisture, 144 Days	Aerated Steam 98-108°C, 0-5 psig 144 Days	Non-Aerated Condensate 20-70°C, 0-180 psig 60-122 Days	Freshwater/Condensate Mixture (aerated) 67 Days
Ferrous Alloy									
Grey Cast Iron		1.0 - 10	1.0 - 10	>10	1.0 - 10	1.0 - 10	>10	-	>10
Low Alloy Steels									
Bore Casings	API/J55	<1.0	1.0 - 10	<1.0	<1.0	1.0 - 10	>10	1.0 - 10	>10
	API/P110	-	-	-	-	-	-	-	-
	API/10M	-	-	-	-	-	-	-	-
	API/H40	-	1.0 - 10	<1.0	<1.0	1.0 - 10	>10	1.0 - 10	>10
Carbon Steels	En3 ²	<1.0	1.0 - 10	<1.0	<1.0	1.0 - 10	>10	1.0 - 10	>10
	En2 ³	<1.0	1.0 - 10	<1.0	<1.0	1.0 - 10	>10	1.0 - 10	>10
Mn-steels	prop-1	-	-	-	-	-	-	-	-
	prop-2	-	-	-	-	-	-	-	-
Mn-steels	En15A	<1.0	1.0 - 10	<1.0	<1.0	1.0 - 10	>10	1.0 - 10	>10
	En5	-	-	-	-	-	-	-	-
Cr-Mn steel	En29B	-	-	-	-	-	-	-	-
Cr-V steel	En47	-	-	-	-	-	-	-	-
Mn-Mo steel	En17	-	-	-	-	-	-	-	-
	En16	-	-	-	-	-	-	-	-
Ni-steel	En37	-	-	-	-	-	-	-	-
High Alloy Steels									
13 Cr	En56A	<1.0	<1.0	<1.0	<1.0	<1.0	1.0 - 10	1.0 - 10	<1.0
13 Cr-Mn	Exp ⁴	-	-	-	-	-	-	-	-
17 Cr	En60	<1.0	<1.0	<1.0	<1.0	<1.0	1.0 - 10	1.0 - 10	<1.0
17 Cr - ZM	En57	<1.0	<1.0	<1.0	<1.0	<1.0	1.0 - 10	1.0 - 10	<1.0
Austenitic SS	En58A, F, C, B, J	-	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Non-Ferrous Alloys									
Titanium	ICI/150	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	-	-
Ti-Al-V	ICI/318A	-	-	-	-	-	-	-	-
K-monel	-	-	-	-	-	-	-	-	-
Monel	B307:MA13	1.0 - 10	<1.0	1.0 - 10	1.0 - 10	1.0 - 10	>10	1.0 - 10	-
Inconel 600	ASTM/B168-41T	1.0 - 10	<1.0	<1.0	<1.0	<1.0	>10	-	-
Copper	BS1038	<1.0	-	1.0 - 10	1.0 - 10	1.0 - 10	>10	1.0 - 10	-
Be-copper	ASTM/B120-41T	-	-	-	-	-	-	-	-
Al-bronze	BS1400	-	-	-	-	1.0 - 10	>10	1.0 - 10	-
	BS1C-AS2c	-	-	-	-	1.0 - 10	>10	1.0 - 10	-
Phosphor-bronze	BS407/s	-	-	-	1.0 - 10	1.0 - 10	1.0 - 10	-	-
Silicon-bronze	BS1942	-	-	-	-	-	-	-	-
60-40 Brass	BS1949	1.0 - 10	<1.0	<1.0	<1.0	<1.0	>10	-	-
70-30 Brass	BS378	-	-	-	-	-	-	-	-
Aluminum	3003	failed ⁵	1.0 - 10	<1.0	failed ⁵	<1.0	<1.0	<1.0	-

¹En specification from B.S. 970 - En series

(NOTE: No chemical analyses of the metals or of the test media are available)

²Proprietary steel: C - 0.28%; Mn - 1.25%; Mo - 0.40%³Proprietary steel: C - 0.18%; Mn - 0.7%; Mo - 0.66%⁴Experimental steel: C - 0.12%; Cr - 12.5%; Mo - 3.1%⁵Weight gain and internal attack

Reference: FO-120

TABLE A-2b

MATERIALS TESTS AT WAIRAKEI, NEW ZEALAND: STRESS CORROSION CRACKING

Stress Corrosion Cracking/Sulfide Stress Cracking								
Equivalent Specification ¹	Rockwell Hardness	Bore Water	Bore Water	Separated Water	Separated Steam	Separated Steam	Aerated Steam	Non-Aerated Condensate
		240°C	50-100°C	125°C, 80 psig	193°C, 180 psig	142-162°C, 40-80 psig	98-108°C, 0-5 psig	20-70°C, 0-180 psig
		63-68 Days	54-93 Days	155 Days	<1% Moisture, 144 Days	10% Moisture, 144 Days	144 Days	60-122 Days
Ferrous Alloys								
Gray cast iron	--	--	--	--	--	--	--	--
Low Alloy Steels								
Bore casings	API/P110	C30-31	0(nf)	0(nf)	--	0(nf)	0	X(f)
	API/J55	B96-99	0(nf)	0(nf)	--	0(nf)	0	0(f)
	API/H40	B90-92	0(nf)	0(nf)	0(nf)	0(nf)	0	0(f)
	En3	B68-72	0(nf)	0(nf)	0(nf)	0(f)	0	0(f)
C-Steels	En2	B80	0(nf)	0(f)	0	0(nf)	0	0
C-Mn Steels	prop-1 ²	B50	0(nf)	0(f)	0(nf)	0(nf)	0	0
	prop-2 ³	B95	0(f)	0(f)	0(nf)	0(nf)	0	0
C-Mn Steels	En15A	B80	0(f)	0(f)	0(nf)	0(nf)	0	0
	En15A	C21-22	--	--	--	0(f)	0(nf)	--
	En5	C15	--	--	--	0(f)	0(nf)	--
Cr-Mn Steels	En29B	B85	--	--	--	0(nf)	0(nf)	--
	En29B	C37-39	0(nf)	X(f)	--	X(f)	0(nf)	X
	En29B	C27-30	0(nf)	0(f)	--	X(f)	0(nf)	--
Cr-V Steels	En29B	C18-19	--	--	--	0(f)	0(f)	--
Mn-Mo Steels	En47	C48	0	X	X	0(f)	X(f)	--
	En17	C53	--	--	--	0(f)	0(f)	--
	En17	C30-33	--	--	--	0(f)	0(f)	--
	En16	C28-30	0(f)	0(f)	--	X	0	0
	En16	C25-27	0(nf)	0(f)	--	0(nf)	--	--
Ni-Steel	En37	B87	--	--	--	X	0	--
High Alloy Steels								
13 Cr	En56A	C30	0(nf)	0(f)	0(nf)	X(f)	0(nf)	X
	En56C	C12-28	--	--	--	0(nf)	0(nf)	--
	En56A	B60-90	0(nf)	0(nf)	0	0(nf)	0(nf)	0
13/3 Cr-Mo	Exp ⁴	C30	--	--	--	X(nf)	X	--
	En60	B98	0(nf)	0(nf)	--	0(nf)	0	--
17 Cr	En60	B85-94	0(nf)	0(nf)	--	0(nf)	0	--
17/2 Cr-Ni	En57	C28-42	0(nf)	X(nf)	0(nf)	X(f)	X	--
	En57	B93-C28	0(nf)	0(nf)	0	0(f)	0	--
Austenitic SS	En58A, F, G, H, J	B70-B90	0(nf)	0(nf)	0	0(nf)	0(nf)	0
Non-Ferrous Alloys								
Ti-Al-V Alloy	ICI/318A	C33	--	--	--	0(nf)	0(nf)	--
Titanium	ICI/150	B93-98	0(nf)	0(nf)	0	0(nf)	0(nf)	0
K-Monel	C25	C25	0(nf)	--	--	--	--	--
Monel	B3072:NA13	B65-69	0(nf)	--	0	0(nf)	0	0
Inconel 600	ASTM/B168-41T	B68-77	0(f)	--	0	0(nf)	0	--
Copper	BS1038	B83	0(nf)	--	--	0(nf)	0	0
Be-Copper Alloy	ASTM/120-41T	C38	X(f)	--	--	X	--	--
	ASTM/120-41T	B47	--	--	--	0(f)	--	--
Al-Bronze	BS1400	B54	--	--	--	0	X	0
	AB1C-AB2c	B63	--	--	--	0	0	0
Phosphor Bronze	BS407/s	B93	--	--	--	0(nf)	0	--
Silicon Bronze	BS1948	B59	--	--	--	X(f)	0	--
Brass (60/40)	BS1949	B49	0(nf)	--	0	0(nf)	0	0
(70/30)	B378	B50	X(nf)	--	--	0(nf)	--	--
Aluminum	Alcoa 3003	H35	--	--	0	0(nf)	0	0

¹ En specification from B.S. 970 - En series² Proprietary steel: C - 0.28%; Mn - 1.2%; Mo - 0.40%³ Proprietary steel: C - 0.18%; Mn - 0.7%; Mo - 0.66%⁴ Experimental steel: C - 0.12%; Cr - 12.5%; Mo - 3.1%

Reference: FO-120

KEY TO TABLE

O = No macroscopic cracking or fracture in a group of specimens

X = Macroscopic cracking or failure of one or more specimens in group tested

(nf) = No microscopic surface fissures detected by metallographic examination

(f) = Microscopic surface fissures detected by metallographic examination

(NOTE: No chemical analyses of the metals or of the test media are available)

TABLE A-3a

CORROSION STUDY AT WAIRAKEI: GENERAL CORROSION AND PITTING

	Tensile Strength Tons/in ²	GENERAL CORROSION AND PITTING (mpy-mile/yr) (P=pitting)							
		Bore Discharge ^a 15 psig 121°C	Separated Steam 40 psig 141°C	Expanded Steam 0 psig 100°C 1.5" super-heat	Wet Separated Steam 10 psig 115°C 10% Moisture	Gas-Free Condensate 100°C pH=6 H ₂ S <1 ppm CO ₂ <1 ppm	Gas-Rich Condensate 71°C pH=6 H ₂ S=30 ppm CO ₂ =400 ppm	Aerated Steam 105°C O ₂ =15,000 ppm	Aerated Condensate 60°C H ₂ S=20 ppm CO ₂ =25 ppm
Iron Base									
Carbon Steel	30-32	2	6	2	5	0.4	3	20	30
Carbon Mn Steel	37	—	—	—	—	—	—	—	—
Carbon Mn Steel	70	—	2	1	4	—	3	—	40
Mn-Mo Steel	45	—	—	—	—	—	—	—	—
Cr-Mo Steel	65	—	—	—	—	—	—	—	—
Ni-Steel	40	—	—	—	—	—	—	—	—
13 Cr Stainless Steel ^a	—	0.3 (P)	0.3 (P)	0.1 (P)	0.1 (P)	—	0.1 (P)	1.0 (P)	0.9 (P)
13 Cr Stainless Steel ^b	45	0.3 (P)	0.3 (P)	0.1 (P)	0.1 (P)	—	0.1 (P)	1.0 (P)	0.9 (P)
13 Cr Stainless Steel ^c	—	0.3 (P)	0.3 (P)	0.1 (P)	0.1 (P)	—	0.1 (P)	1.0 (P)	0.9 (P)
13 Cr Stainless Steel ^d	30	0.3 (P)	0.3 (P)	0.1 (P)	0.1 (P)	—	0.1 (P)	1.0 (P)	0.9 (P)
13 Cr Stainless Steel ^e	30	0.3 (P)	0.3 (P)	0.1 (P)	0.1 (P)	—	0.1 (P)	1.0 (P)	0.9 (P)
18/8 Cr/Ni SS	40	0 (P)	0	0.1 (P)	0	0	0	0	0 (P)
18/8/1 Cr/Ni/Mo SS	41	—	—	—	—	—	—	—	—
18/8/3 Cr/Ni/Mo SS	40-46	0	0	0	0	0	0	0	0
18/12/1 Cr/Ni/Mo SS	41	—	0	0	0	0	0	0	0
18/12/2 Cr/Ni/Mo SS	40	—	—	—	—	—	—	—	—
Rex 326 SS	45	—	—	—	—	—	—	—	—
35/10 Ni/Cr SS	—	—	—	—	—	—	—	—	—
Gray Cast Iron	—	2	3	—	—	—	—	10	90
Ni-Silicon Cast Iron	—	2	0.5	—	—	—	—	1	—
Ni-Resist Cast Iron	—	1	1	—	—	—	—	10	—
Copper Base									
Copper	16	8	2	1	3	0.1	5	40	40
Silicon Bronze	25	10	3	—	—	—	—	20	—
Phosphor Bronze	40	6	2	—	—	—	—	9	—
Aluminum Bronze (Cast)	30	—	3	0.7	3	—	1	10	—
60/40 Brass	26	4	0.4	0.2	0.8	0	0.2	40	40
Nickel Base									
Nickel	25	2	1	—	—	0.1	—	8	—
Inconel	30	3	4	0.5	1	0.1	4	10	20
Inconel	35	2	0	—	0	—	—	80	—
Other Bases									
Aluminum (Alcoa 35)	7	0 (P)	0 (P)	0 (P)	0 (P)	0 (P)	0 (P)	0 (P)	0.2 (P)
Titanium	50	—	0	0	—	—	—	0	—
Plated Steel									
Nickel Plate (10 mil)	—	—	1	0.1	1	—	2	Plating Destroyed	30
Chrome Plate (6 mil)	—	0.2	0	—	0	—	—	0	—
Galvanized (1.5 mil)	—	0.2 (P)	0 (P)	—	—	0.1 (P)	—	Plating Destroyed	Plating Destroyed

EROSION (mpy)	
Separated Steam 6-70 psia 45-148°C 50-600 fpm	Wet Separated Steam 15-20 psia 100-110°C 9% Moisture 850-1050 fpm
11	113
7	73
—	—
11	77
7	44
—	—
—	—
—	—
—	—
<3.5	7
—	—
<3.5	4
—	—
<3.5	<3.5
<3.5	<3.5
—	—
<3.5	<3.5
<3.5	11
—	—
—	—

^a Hardness not specified
^b Brinell hardness 195-225 (machined from turbine blade)
^c Brinell hardness 285 (tempered 450°C)
^d Brinell hardness 180 (tempered 750°C)
^e Brinell hardness 150 (annealed)

Reference: MA-672

Bore Discharge Composition		
Component	Steam Phase	Water Phase
CO ₂	3400 ppm	5 ppm
H ₂ S	140 ppm	0.5 ppm
NH ₃	15 ppm	3 ppm
Boric Acid	0.6 ppm	160 ppm
F ⁻	0.03 ppm	6 ppm
Cl ⁻	nll	1300 ppm
Na ⁺	nll	900 ppm
SiO ₂	nll	300 ppm

TABLE A-3b

CORROSION STUDY AT WAIRAKEI: STRESS CORROSION CRACKING

	Tensile Strength Tons/in ²	STRESS CORROSION CRACKING (Number of Failures/Total of Samples)								
		Bore Discharge ^a 15 psig 121°C	Separated Steam 40 psig 141°C	Expanded Steam 0 psig 100°C 1.5" super-heat	Wet Separated Steam 10 psig 115°C 10% Moisture	Gas-Free Condensate 100°C pH=6 H ₂ S <1 ppm CO ₂ <1 ppm	Gas-Rich Condensate 71°C pH=6 H ₂ S=30 ppm CO ₂ =400 ppm	Aerated Steam 105°C O ₂ =15,000 ppm	Aerated Condensate 60°C H ₂ S=20 ppm CO ₂ =25 ppm	Simulated Standby Separated Steam for 8 hrs. Air for 16 hrs.
Iron Base										
Carbon Steel	30-32	0/1	0/4	0/1	0/1	0/1	0/1	0/4	0/1	—
Carbon Mo Steel	37	—	0/2	—	—	—	0/2	0/2	—	—
Carbon Mn Steel	70	—	—	—	—	—	—	—	—	—
Mn-Mo Steel	45	—	2/2	—	—	—	0/2	0/2	—	—
Cr-Mo Steel	65	—	2/2	—	—	—	2/2	—	—	—
Ni-Steel	40	—	2/2	—	—	—	—	0/1	—	—
13 Cr Stainless Steel ^a	—	—	—	—	—	—	—	—	—	—
13 Cr Stainless Steel ^b	45	2/3	0/7	0/2	0/3	—	2/6	3/5	2/2	3/10
13 Cr Stainless Steel ^c	—	—	0/4	—	—	—	2/2	—	—	4/4
13 Cr Stainless Steel ^d	30	—	0/2	—	—	—	0/2	0/2	—	—
13 Cr Stainless Steel ^e	30	0/1	0/4	—	—	—	0/3	0/1	0/1	0/4
18/8 Cr/Ni SS	40	0/1	0/3	0/2	0/2	0/1	0/2	2/3	0/2	—
18/8/1 Cr/Ni/Mo SS	41	—	0/2	—	—	—	0/2	0/2	—	—
18/8/3 Cr/Ni/Mo SS	40-46	0/1	0/4	0/1	0/1	0/1	0/3	0/4	0/1	—
18/12/1 Cr/Ni/Mo SS	41	—	0/2	—	—	—	0/2	0/2	—	—
18/12/2 Cr/Ni/Mo SS	40	—	0/1	0/1	0/1	—	—	—	—	—
Rex 326 SS	45	—	0/2	—	—	—	0/2	0/2	—	—
35/10 Ni/Cr SS	—	—	0/2	—	—	—	0/2	2/2	—	—
Gray Cast Iron	—	—	—	—	—	—	—	—	—	—
Ni-Silicon Cast Iron	—	—	—	—	—	—	—	—	—	—
Ni-Resist Cast Iron	—	—	—	—	—	—	—	—	—	—
Copper Base										
Copper	16	0/1	0/2	0/1	0/1	0/1	0/1	0/2	0/1	—
Silicon Bronze	25	0/1	0/1	—	—	0/1	—	—	—	—
Phosphor Bronze	40	0/1	0/1	—	—	0/1	—	—	—	—
Aluminum Bronze (Cast)	30	—	0/1	0/1	0/1	—	0/1	1/1	—	—
60/40 Brass	26	0/2	0/2	0/1	0/1	0/1	0/1	0/1	0/1	—
Nickel Base										
Nickel	25	—	—	—	—	—	—	—	—	—
Monel	30	0/1	0/2	0/1	0/1	0/1	0/1	0/2	0/1	—
Inconel	35	0/1	0/2	—	0/1	—	—	0/2	—	—
Other Bases										
Aluminum (Alcoa 35)	7	0/1	0/2	0/1	0/1	0/1	0/1	0/2	0/1	—
Titanium	50	—	0/3	0/1	—	—	0/2	0/3	—	—
Plated Steel										
Nickel Plate (10 mil)	—	—	—	—	—	—	—	—	—	—
Chrome Plate (6 mil)	—	—	—	—	—	—	—	—	—	—
Galvanized (1.5 mil)	—	—	—	—	—	—	—	—	—	—

^a Hardness not specified
^b Brinell hardness 195-225 (machined from turbine blade)
^c Brinell hardness 285 (tempered 450°C)
^d Brinell hardness 180 (tempered 750°C)
^e Brinell hardness 150 (annealed)

Reference: MA-672

Bore Discharge Composition		
Component	Steam Phase	Water Phase
CO ₂	5400 ppm	5 ppm
H ₂ S	140 ppm	0.5 ppm
NH ₃	15 ppm	3 ppm
Boric Acid	0.6 ppm	160 ppm
F ⁻	0.03 ppm	6 ppm
Cl ⁻	nil	1500 ppm
Na ⁺	nil	900 ppm
SiO ₂	nil	300 ppm

TABLE A-4
INTERNATIONAL NICKEL COMPANY CORROSION TESTS
AT WAIRAKEI, NEW ZEALAND

	Non-Aerated Steam		Non-Aerated Condensate		Aerated Condensate		Turbine Discharge	
	General Corrosion (mpy)	Growth of Deepest Pit ¹ (mpy)	General Corrosion (mpy)	Growth of Deepest Pit ¹ (mpy)	General Corrosion (mpy)	Growth of Deepest Pit ¹ (mpy)	General Corrosion (mpy)	Growth of Deepest Pit ¹ (mpy)
Iron base								
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 ²	--	--	--	--	--	--	<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
ACT CF-8	--	--	--	--	<0.1	--	<0.1	no pits
ACT 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
Nickel base								
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	--	--	--	--
Copper base								
10Ni-5Al-bronze	--	--	--	--	0.1	4.0	1.7	29.8

(-) means no result reported.

¹ Growth of deepest pit based on depth of maximum pit after 552 days exposure.

² Sensitized.

Description of Test Environments

Non-Aerated Steam: Field spool test holder in geothermal steam line. Temperature = 147°C-153°C. Steam contains 1 percent noncondensable gases (H₂S, CO₂, CH₄).

Non-Aerated Condensate: Temperature = 116°C, pH = 5.25. Contains CO₂, H₂S and NH₃.

Aerated Condensate: Temperature = 50°C, 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.

Turbine Discharge: Field spool holder between turbine and barometric condenser. Temperature = 52°C.

Reference: BA-539

A.1.3.1 General Corrosion

- Because of chemical impurities in geothermal steam, particularly chlorides, H_2S and CO_2 , corrosion rates of common engineering alloys are 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, is low enough to insure adequate service life. Mild steel is adequate for air-free service if a moderate corrosion allowance is made.
- Aeration of geothermal media drastically increases (ten-fold or more) the corrosion of most engineering alloys with the exceptions of austenitic stainless steels (especially those containing molybdenum), titanium, and chromium plated steels. Galvanizing is unsuccessful in aerated geothermal media.
- Corrosion rates of most alloys in bore water at $250^\circ C$ are low compared to those in lower temperature media. Pitting is characteristically absent in bore water at $250^\circ C$.

A.1.3.2 Erosion-Corrosion

Empirical tests at Wairakei indicated that the following steels have sufficient resistance to erosion-corrosion by water droplets in steam (containing 9% moisture) at 900 fps (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," 35/10 Ni-Cr. Erosion-corrosion resistance is directly related to static corrosion resistance and not to hardness as is often assumed (MA-672).

A.1.3.3 Stress Corrosion Cracking (SCC) of Austenitic Stainless Steels

Tests indicate that even under conditions of high stress, austenitic stainless steels are not susceptible to SCC in oxygen-free media. In the presence of dissolved oxygen, the lower temperature and chloride concentration limits appear to be 50°C and 5 ppm Cl⁻. There appears to be no lower critical stress limit for SCC.

A.1.3.4 Hydrogen Sulfide Effects

At Wairakei the following observations were made concerning sulfide stress cracking (SSC):

- Medium and high strength steels are susceptible to SSC in geothermal media up to at least 190°C.
- Mild steels and low strength alloys resist SSC even under severe constant deformation tests. The highest safe

tensile strength appears to be 88 ksi* for carbon and low alloy steels and 110-120 ksi for high chromium alloys.

- Susceptibility to SSC is often related to hardness rather than yield strength (HU-200). 13 Cr turbine blading was resistant at a hardness below Brinell 180 (Rc~8) and vulnerable above Brinell 190 (Rc~11).
- Delayed fracture can occur in severely notched low strength alloys exposed to cold H₂S-bearing condensate at strengths below 88 ksi.
- H₂S-bearing dry steam is innocuous.
- SSC of highly susceptible steels did not occur in bore water at 240°C but did occur in the same water at 50°C.
- Blistering has been observed in some low strength alloys.
- Hydrogen infusion rates decrease to very low values after two to three weeks exposure above 100°C, probably because of corrosion films.
- Permeation rate can be greatly reduced by surface coatings such as Apexior No. 1 paint or by chemically formed Fe₃O₄ coatings.

*ksi = thousand pounds per square inch.

There is an inverse relationship between infusion rate and temperature in bore water due to the formation of magnetite at higher temperatures. The magnetite on the iron surface appears to impose a barrier (equilibrium and/or kinetic) which reduces the hydrogen concentration below the corroding surface (FO-123).

A.1.4 Plant Experience at Wairakei

Overall plant experience (MA-668), erosion and thermal stress of production casings (SM-160), and well casing problems (FO-119) have been documented for the Wairakei power plant.

A.1.4.1 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 susceptibility to sulfide stress cracking. 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 casing with careful cementing of the annuli has controlled this problem.

Thermal stress is severe. It can exceed 60 ksi and may cause mechanical failure of low strength casing alloys. High strength alloys (N-80 and above) should be avoided because of sulfide stress cracking. The medium strength sulfide resistant French steel APS 10M4 has shown promise in laboratory tests at

Wairakei (MA-682). Thermal stress may be alleviated by careful cementing to avoid unsupported regions. Careful cementing also prevents the formation of trapped water pockets which will collapse the casing once production is begun. Keeping bores flowing after initial "blow-in" will reduce thermal stress and prevent the formation of cold, nonaerated H_2S -bearing condensate--the main source of sulfide stress cracking.

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 is required. Transmission pipelines of carbon steel are satisfactory if the media remains air free. Air inleakage must be avoided.

A.1.4.2 Turbines

The turbines at Wairakei are made of conventional turbine construction materials (cast steel casings, carbon steel rotors, 13 Cr 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 13 Cr steel. The rivets are annealed. Care is used to seal the joints in low pressure casing as thoroughly as possible to avoid air ingress and accelerated corrosion by aerated media. Blade velocities are limited to 900 fps and moisture to 9 percent to avoid excessive blade corrosion. These turbines have given good service.

A.1.4.3 Electrical Equipment

Atmospheric H_2S tarnishes copper and silver contacts. Erosion-corrosion of copper contacts exposed to H_2S is rapid. At Wairakei, silver contacts are replaced in critical equipment

with platinum contacts. This problem has been studied extensively at The Geysers in California. Their results are given in Section A.3.4.

A.2 CORROSION AT THE CERRO PRIETO GEOTHERMAL POWER PLANT

The Cerro Prieto geothermal power plant has operated since 1973. In spite of some serious material problems, the plant has operated continuously except for scheduled downtimes. The Cerro Prieto project provides operating experience and corrosion test data from a single-flash, liquid-dominated system. The similarity between Cerro Prieto geothermal media (Table A-5) and the fluids of East Mesa, Holtville, and Heber, California indicates that corrosion phenomena may be similar at all sites, and Cerro Prieto experience will aid in the design of future power plants.

A.2.1 System Description

The Cerro Prieto geothermal resource is liquid-dominated. Surface manifestations cover an area of about 30 square kilometers. The utilization mode is single-flash (bore-flashing). As of 1976, 53 deep wells had been drilled in this area with depths of 700m to 2000m. Flow is obtained through preslotted or gun perforated casings after cementing the production casing, except the bottom 150m to 300m, where hot strata are located. High enthalpy water at 275-320°C flows through the perforated casing and is conducted to the surface through the 7 5/8" production casing (SC-448). As the water ascends through the production casing, the hydrostatic pressure drops and the water partially flashes to steam. The flow through the well tree is a two-phase fluid containing from 20 to 40 weight percent steam. The fluid is passed through a Webre type centrifugal separator at the wellhead (SC-448) and through a secondary separator at the power plant (GE-119). The separated water is sent to an evaporating pond (SC-448).

TABLE A-5
COMPARISON OF FLUIDS FROM PRODUCTION
WELLS AT CERRO PRIETO

	Low T.D.S. (Well M-8)		Medium T.D.S. (Well M-31)		High T.D.S. (Well M-11)	
	After-Flash fluid ¹ (ppm)	Pre-Flash fluid ² (ppm)	After-Flash fluid ¹ (ppm)	Pre-Flash fluid ² (ppm)	After-Flash fluid ¹ (ppm)	Pre-Flash fluid ² (ppm)
pH	8.21 ³	5.43 ⁴	8.05 ³	5.35 ⁴	7.90 ³	5.34 ⁴
T.D.S.	17,068	—	22,284	—	27,123	—
SiO ₂	974	590	833	490	1,345	610
Na	5,257	4,730	6,913	4,410	8,229	5,600
K	1,310	1,180	1,540	1,110	2,032	1,230
Ca	258	272	463	287	550	369
Mg	0.04	0.2	0.16	0.1	0.34	0.8
Cl	10,128	9,040	13,205	8,820	16,129	11,400
SO ₄ ²⁻	10	9	18	3	12	27
HCO ₃ ⁻	32.49	38	57.82	28	59.11	27
CO ₂ ¹	11.38	—	6.32	—	0	—
CO ₂	—	2,580	—	2,210	—	1,250
H ₂ S	—	624	—	593	—	310
B	15.52	12	18	11	—	13
Ba	5.72	—	7.14	—	11.48	—
Br	12.5	—	13	—	36.4	—
Ce	25.5	—	34.9	—	40.9	—
Li	14.5	10.9	18.4	11.1	25.2	13.7
Rb	8.4	—	9.7	—	12.3	—
Sr	7.3	—	15.3	—	15	—
Al	0.03	—	0.03	—	0.03	—
As	0.6	—	0.89	—	1.1	—
Be	<0.03	—	<0.03	—	<0.03	—
Co	<0.01	—	<0.01	—	<0.01	—
Cr	<0.5	—	<0.5	—	<0.5	—
F	—	—	—	—	—	—
Fe	—	—	0.26	—	—	—
I	0.45	—	0.54	—	0.7	—
Mn	0.04	—	0.15	—	—	—
Ni	<0.01	—	<0.01	—	<0.01	—
Pb	—	—	0.02	—	—	—
Zn	—	—	0.01	—	—	—

¹ Separator discharge fluid at 1 atm and 100°C after steam flash.

² Calculated fluid composition corrected for steam loss.

³ pH at 25°C.

⁴ Calculated pH.

WELL DATA

	M-8	M-31	M-11
Temperature(bottom of hole)	305°C	313°C	261°C
Production depth	1220 m.	1160 m.	1150 m.
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 on 21 wells.

Source: LA-312

20 to 80 tons/hour of steam at 100 psig are obtained from each well. As of 1976, 13 wells provide steam to maintain two units of 37.5 MW each, at full load, at a steam rate of 9.4 kg/kwh (SC-448).

A.2.2 Cerro Prieto Geothermal Fluid

Based on isotopic analyses, the Cerro Prieto geothermal fluid is meteoric and is derived mainly from the Colorado River (SC-448). 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 (SC-448). Analyses of geothermal fluid from three production wells are given in Table A-5. The three analyses (from 115 presented in LA-312) show the range of brine compositions at Cerro Prieto.

A.2.3 Corrosion Tests at Cerro Prieto

From 1969 to 1970 a corrosion test program was performed jointly by the Comision Federal de Electricidad of Mexico and Tokyo Shibaura Company (Toshiba) of Japan. The purpose was to confirm the corrosion resistance of previously selected materials to be used for construction of the power plant which was ordered in 1968.

Coupons were used in the general corrosion test. The stress corrosion specimens were U-bend strips stressed beyond the yield point and retained under stress by a bolt. The erosion-corrosion specimens were cylinders 6 cm long and 1 cm in diameter (GE-119). The results of the tests and details of test conditions are presented in Table A-6. Compositions and uses of materials tested are in Table A-7. No distinction was made between stress corrosion cracking and sulfide stress cracking.

TABLE A-6a
CORROSION STUDY AT CERRO PRIETO

	CORROSION ¹											EROSION ¹	
	Non-Aerated Steam			Aerated Steam			Low Velocity Condensate			High Velocity Condensate			High Velocity Stream
	General (mpy)	Pitting (rate in mpy)	Stress (# failed/ # tested)	General (mpy)	Pitting (rate in mpy)	Stress (# failed/ # tested)	General (mpy)	Pitting (rate in mpy)	Stress (# failed/ # tested)	General (mpy)	Pitting (rate in mpy)		
Low Alloy Steels													
Low carbon	---	---	---	---	---	---	12.20	no pits	0/3	27.54	---	1.43	
1 Cr-Mo-.25 V	1.57	---	2/2 ^a	8.27	---	1/2	---	---	---	---	---	3.28	
1.5 Cr-1 Al-0.25 Mo	---	38.18	---	---	33.46	---	---	---	---	---	---	4 ^d	
3.5 Ni-1.75 Cr-Mo-V	0.63	4.72	---	13.40	27.54	0/5 ^b	---	---	---	---	---	1.99	
ASTM A205	1.57	---	---	2.56	---	---	---	---	---	---	---	2.70	
Stainless Steels													
AISI Type 304	---	---	---	---	---	---	0.03	no pits	0/3	0.01	no pits	0.12	
AISI Type 410	---	---	---	---	---	---	0.59	38.19	---	3.15	33.46	---	
12 Cr	0.39	0.94	0/3	3.94	66.93	0/3 ^a	---	---	---	---	---	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 ^b	---	---	---	---	---	0.72 ^c	
15 Cr-1.7 Mo	0.18	5.90	0/3	0.55	47.27	0/3	---	---	---	---	---	0.46	
Non-Ferrous Alloys													
Ti-6Al-4V	---	---	---	2.24	106.30	---	---	---	---	---	---	---	
Deoxidized copper	---	---	0/3	20.07	---	2/2 ^c	9.45	no pits	0/4	2.52	---	---	
Naval brass	---	---	---	---	---	---	2.83	no pits	0/3	8.66	---	---	
Aluminum	---	---	---	2.24	106.30	---	0.16	no pits	0/2	14.57	---	---	

(---) = no data available or no sample tested

¹exposure duration = 150 days
²exposure duration not stated
³exposure duration = 90 days
⁴% decrease in Reducement Limit

^amicroscopic cracks observed
^bintergranular corrosion
^cfailure due to general corrosion
^dweight gain

Composition of Test Media
(average of 150 days)

Note: The corrosion rate was calculated from weight loss data

Parameter	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
Temperature	147°C	140°C	70°C	45°C	40°C
CO ₂	19,500 ppm	19,500 ppm	16,000 ppm	no data	no data
H ₂ S	2,000 ppm	2,000 ppm	1,600 ppm	no data	no data
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	no data	426 fpm	no data	1.6 fpm	0.002 fpm
Moisture	0.7%	0.6%	0.7%	a	a

^adoes not apply to this phase

Source: CB-119

TABLE A-6b

CORROSION STUDY AT CERRO PRIETO: EFFECT ON MECHANICAL PROPERTIES

	EFFECT ON MECHANICAL PROPERTIES														
	Before Exposure				Exposed to Non-Aerated Steam					Exposed to Aerated Steam			Exposed to Low Velocity Condensate		
	T.S. (KSI)	Y.S. (KSI)	2" E Elong- ation	Endurance Limit (KSI)	T.S. (KSI)	Y.S. (KSI)	2" E Elong- ation	Endurance Limit (KSI)	Decrease ^a %	T.S. (KSI)	Y.S. (KSI)	2" E Elong- ation	T.S. (KSI)	Y.S. (KSI)	2" E Elong- ation
Low Alloy Steels															
Low carbon	—	—	—	—	—	—	—	—	—	—	—	—	24.0	11.9	37.7
1 Cr-Mn-.25 V	54.4	44.1	17.3	23.5	53.9	43.5	16.3	17.1	27.4	53.0	41.1	13.2	—	—	—
1.5 Cr-1 Al-0.25 Mn	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
3.5 Ni-1.75 Cr-Mn-V	57.7	49.6	17.3	28.4	57.3	50.7	16.3	17.4	38.6	53.6	45.0	10.9	—	—	—
ASTM A285	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Stainless Steels															
AISI Type 304	—	—	—	—	—	—	—	—	—	—	—	—	42.3	21.9	70.3
AISI Type 410	—	—	—	—	—	—	—	—	—	—	—	—	37.4	23.0	27.3
12 Cr	48.0	39.9	19.6	26.1	47.3	38.8	20.1	21.3	18.3	48.1	37.2	12.8	—	—	—
12 Cr-Mn-W	63.2	54.5	15.6	31.0	63.3	51.3	16.3	26.5	14.6	60.3	44.3	4.8	—	—	—
12 Cr-0.2 Al	39.5	24.3	25.1	17.1	39.0	24.8	27.6	13.9	18.8	36.6	24.6	20.2	—	—	—
15 Cr-1.7 Mn	31.7	20.1	31.1	14.5	30.8	18.8	32.1	14.5	11.7	30.8	18.5	25.4	—	—	—
Non-Ferrous Alloys															
Stellite #6	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Deoxidized copper	11.5	15.8	23.1	—	15.4	14.1	8.5	—	—	—	—	—	15.4	15.2	21.0
Naval brass	—	—	—	—	—	—	—	—	—	—	—	—	28.0	21.4	24.8
Aluminum	—	—	—	—	19.9	—	10.8	—	—	—	—	—	20.3	—	7.3

(—) = no data available or no sample tested

T.S. = Tensile Strength

Y.S. = Yield Strength

Composition of Test Media
(average of 150 days)

Parameter	Non-Aerated Steam	High Velocity Steam	Aerated Steam	High Velocity Condensate	Low Velocity Condensate
Pressure	61 psig	56.8 psig	14.7 psia	14.7 psia	14.7
Temperature	147°C	140°C	70°C	45°C	40°C
CO ₂	19,500 ppm	19,500 ppm	16,000 ppm	no data	no data
H ₂ S	2,000 ppm	2,000 ppm	1,600 ppm	no data	no data
Cl ⁻	13.3 ppm	13.3 ppm	7.0 ppm	60 ppm	50 ppm
pH	a	a	a	6.4-7.3	6.8-7.8
Velocity	no data	476 fpm	no data	1.8 fpm	0.002 fpm
Moisture	0.7%	0.6%	0.7%	a	a

^adata not apply to this phase

Source: CB-119

TABLE A-7
CHEMICAL COMPOSITION AND USE OF MATERIALS TESTED AT THE
CERRO PRIETO GEOTHERMAL POWER PLANT

	Nominal Composition (Percent)																Use in Power Plant
	Al	C	Co	Cr	Cu	Fe	Mn	Mo	Ni	P	S	Si	Su	V	W	Zn	
Ferrous Alloys																	
Low carbon steel	--	0.25M	--	--	--	Rem	--	--	--	--	--	--	--	--	--	--	Rotor
1-Cr-Mo-0.25 V	--	0.30	--	1.05	--	Rem	0.75	1.3	0.60M	0.20M	0.20M	0.30M	--	0.25	--	--	
1.5 Cr-1 Al-0.25 Mo	1.0	0.32	--	1.25	--	Rem	0.45M	0.23	--	0.30M	0.30M	0.25M	--	--	--	--	
3.5 Ni-Cr-Mo-V	--	0.25	--	1.75	--	Rem	0.30	0.40	3.5	0.20M	0.20M	0.10M	--	0.11	--	--	
ASTM A-285	--	0.30M	--	--	0.35M	Rem	0.80M	--	--	0.04M	0.04M	--	--	--	--	--	Outer and inner turbine casing Turbine buckets Turbine buckets Nozzle partition Labyrinth strips Gas ejector
12 Cr	--	0.12	--	12.0	--	Rem	0.50	0.20	0.50M	0.30M	0.30M	0.50M	--	--	--	--	
12 Cr-Mo-W	--	0.22	--	11.7	--	Rem	0.70	1.0	0.70	0.20M	0.10M	0.50M	--	0.25	1.0	--	
12 Cr-0.2 Al	0.2	0.25	--	13.0	--	Rem	0.50	--	0.5M	0.30M	0.30M	0.50M	--	--	--	--	
15 Cr-1.7 Mo	0.5M	0.05	--	15.0	--	Rem	0.50M	1.7	0.50M	0.30M	0.30M	0.50M	--	--	--	--	
AISI Type 304	--	0.8M	--	19.0	--	Rem	2.0M	--	10.0	0.05M	0.03M	1.0M	--	--	--	--	
AISI Type 410	--	0.15	--	12.5	--	Rem	--	--	--	--	--	--	--	--	--	--	
Non-Ferrous Alloys																	
Stellite #6	--	1.0	Rem	2.8	--	3.0	--	--	--	--	--	--	--	--	2.8	--	6th stage rotor blades (coat)
Copper	--	--	--	--	99.9m	--	--	--	--	--	--	--	--	--	--	--	Tube sheets, oil coolers Oil coolers
Naval Brass	--	--	--	--	59.3	--	--	--	--	--	--	--	0.75	--	--	39.95	
Aluminum	99.9m	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	

(--)= no results reported

Source: GE-119 and BA-539

A.2.3.1 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.
- The corrosion rate of 1 Cr-Mo-0.5 V steel was similar to the corrosion of carbon steel in nonaerated steam. Microscopic cracks were observed in the stress corrosion specimen. Aeration increased general corrosion rates by a factor of five. One of two stress corrosion specimens failed.
- In nonaerated steam the general corrosion rate of 3.5 Ni-Cr-Mo-V alloy was less than 1 Cr-Mo-0.5 V alloy. It was not stress corrosion tested in nonaerated steam. The endurance limit decrease was 39 percent. Aeration increased general corrosion 20 times. Stress corrosion specimens showed intergranular attack.
- In aerated steam 1.5 Cr-1Al-0.25 Mo alloy (nitrided steel) showed a partial spalling but had good general corrosion resistance.

- In nonaerated steam aluminum was not corroded. Aeration of steam led to pitting in excess of 100 mpy.

Stainless Steels

- In nonaerated steam, 12 Cr alloy (used for turbine buckets) had a very low (<0.5 mpy) general 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, only a slight decrease in yield strength, and a decrease in endurance limit (15 to 19 percent). Aeration increased general corrosion ten times and pitting 70 times. Microscopic cracks were observed on the stress corrosion specimen.
- In nonaerated steam 12 Cr-Mo-W steel was comparable to 12 Cr in terms of general corrosion, pitting, and stress corrosion cracking. Erosion-corrosion resistance was better than 12 Cr steel. Changes in mechanical properties were similar to 12 Cr steel. Aeration caused a ten-fold increase in general corrosion, a seventy-fold increase in pitting, and intergranular corrosion of the stress corrosion specimen.
- In nonaerated steam, 12 Cr-0.2 Al alloy (used for nozzle partitions) had a low general corrosion rate. No pitting was reported. The alloy was resistant to stress corrosion and erosion-corrosion resistance was similar to

12 Cr steel. Aeration increased general corrosion to a lesser degree than for 12 CR-Mo-W steel, and no pitting was reported. 15 Cr-1.7 Mo 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 12 Cr-Mo-W.

A.2.3.2 Corrosion Results in Condensate*

- The corrosion rate in high velocity (1.5 fps) 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 Type 410 steel pits at a rate of more than 30 mpy. General corrosion was ten times that of AISI Type 304.
- AISI type 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 Type 304 heat exchanger tubing would not serve in aerated condensate. Titanium tubes have given good service.

*It was not clear whether or not the condensate used in the tests was aerated and the H_2S concentration was not given. The pH was about 7.

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

A.2.4 Operating Experience at Cerro Prieto

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 nonaerated liquid or steam. When oxygen was introduced to 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.

A.2.4.1 Bore Casings and Surface Equipment

Several problems and two blowouts have occurred due to the rupture or collapse of bore casings 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 (GE-119).

After geothermal wells have been completed, they remain out of production until their temperature, which decreased during drilling, rises again and facilitates their activation. During this time, internal pipe walls of some of the wells have been

attacked by elevated concentrations of H_2S . Reservoir gases such as CO_2 and H_2S flow into a well out of production and cause the water level to oscillate significantly. H_2S 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 (ME-S-250). 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 (GE-119). This behavior corresponds to that at Wairakei where casing steels H40 and K55 have failed rapidly in cold H_2S -bearing condensate (FO-120, MA-682, SM-160, FO-119).

Leaks of hydrothermal fluids between well casings or between casings and the walls of the hole lead to degradation of the cement 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 up to the surface. The result is bubbling and escape of gases and steam promoting corrosion on the outside of the well casing. This is prevented through intensive maintenance with temperature resistant paints or by adding high temperature lubricants (ME-S-250).

Galvanic coupling of production pipe with packing flanges has promoted crevice corrosion of the casing at the well-head. 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 (ME-S-250, GE-119).

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 a sand-water-steam flow at high velocity (GE-119).

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 application of protective paints.

The Cerro Prieto discharge was initially passed through steel vertical silencers. The combination of geothermal media 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 (ME-S-250).

There have been few corrosion problems in the conduction lines for the separated hot water (160-180°C) which transport the brine from the separators to the evaporating pond. However, there has been a case in which severe scaling was accompanied by corrosion. 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 (ME-S-250).

A.2.4.2 Steam Conduction System

Carbon-steel steam conduction lines normally suffer a slight internal attack and become coated with an iron sulfide film. The film is usually not a problem, but occasionally the film dislodges and blocks steam traps or enters the turbine. Steam traps require intensive maintenance to prevent and clear

blockage by iron sulfide flakes. The problem has been somewhat remedied by substituting continuous condensate purges for most of the steam traps (ME-S-250).

A.2.4.3 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," with only slight erosion of the silver used to solder the facings to the 12Cr steel blades (GE-119). The major problem was the scaling of silica in the first stage nozzles and buckets (GE-119, SC-448). This problem was due to the poor separation of water and steam in the wellhead and secondary separators, allowing carryover of droplets supersaturated with silica (SiO_2) and calcium carbonate (SC-448).

After two years of operation, improved steam separators were installed to give 99.99% quality steam. The service cycle has been extended to 18 months, and a two-year cycle is possible (ME-S-250).

The rotor and 12Cr turbine buckets have shown only slight attack after four years of operation. Their highest attrition rate is due to erosion from: (a) water droplets, (b) carryover of iron sulfide particles in the steam, or (c) sand blasting carried out during preventive maintenance to eliminate the scale which is regularly deposited during operation. Corrosion is slightly more accentuated in seals where steam is mixed with geothermal gases and atmospheric oxygen (ME-S-250).

A.2.4.4 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 H_2S , CO_2 , NH_3 , chlorides, other impurities, and sulfide-oxidizing bacteria.

Extensive corrosion occurred originally on the water side of the aluminum tubes in the heat exchangers of the oil cooling system. A large percentage was perforated in 15 days of operation, and all showed signs of pitting. The tubes were replaced by Type 304 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. Bacterial growth, which promotes the pitting, is accelerated when the water is not flowing. Titanium tubing is planned for use in the next unit (ME-S-250).

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 (ME-S-250).

The barometric condenser is the direct contact type where 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 Type 304 on the bottom. Water removes the protective coating in some areas, and attack on the carbon steel walls occurs. There has been no corrosion through the stainless steel layer. Condensers for future units will be clad with Type 316. 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 (ME-S-250). 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 Type 316 is planned for use in future units (ME-S-250).

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

Closed concrete channels are used for conducting cooling water between the condenser and cooling tower. These channels were originally protected with a 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 PVC covers.

The combination of H_2S , steam, and anaerobic bacteria caused degradation in the concrete channel ceilings in a zone with 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 H_2S to H_2SO_4 , 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 protected with

coal tar epoxy. Slight corrosion has resulted where the paint has worn off. Most of the screws and metal fittings are Type 304 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 (ME-S-250).

A.2.4.5 Electrical System

The electrical system is generally protected by using "clean" rooms with filtered air conditioning systems. Copper wire plated with tin or cadmium has presented no problems. Some of the silver and copper parts have been attacked by H_2S , requiring maintenance. Exterior high voltage contacts in the substation are copper that was covered with gold before being replaced in operation. These contacts are also attacked by H_2S but have given no problems (ME-S-250).

A.3 CORROSION AT THE GEYSERS

The steam-dominated geothermal resource at The Geysers, California, is the only developed geothermal resource in the United States. Relatively long-term corrosion experience with geothermal steam and condensate from this plant has been accumulated, but caution should be used in applying corrosion experience from The Geysers to liquid-dominated resource power plants. The steam at The Geysers is not saline, and the condensate contains only trace chloride. Table A-8 gives the nominal composition of steam at The Geysers (TO-089).

TABLE A-8
NOMINAL COMPOSITION OF GEOTHERMAL STEAM
AT THE GEYSERS (TO-089)

<u>Component</u>	<u>ppm (by weight)</u>
CO ₂	3260
H ₂ S	222
NH ₃	194
H ₂	56
pH (condensate)	7.7 - 8.1

A.3.1 Test Methods and Conditions

In order to evaluate the effect of H₂S abatement with Fe₂(SO₄)₃, long-term corrosion tests of a number of alloys were begun in 1972. Sets of 2-1/4 inch diameter coupons of non-stressed metal 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 H₂S, CO₂, NH₃, and trace Cl⁻ present. The media in unit 2 also contained approximately 30 ppm iron as Fe₂(SO₄)₃ for the abatement of H₂S emission. General 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. The crevice was formed between the coupon and the insulating spacer (GE-119). The results of these tests are presented in Table A-9. Tests with the addition of Fe⁺³ are not typical of fluids in power plants unless the media are oxidized fluids or unless Fe⁺³ is added for H₂S abatement.

TABLE A-9
CORROSION STUDY IN CONDENSATE HOT WELL AT THE GEYSERS, CA

	Without $\text{Fe}_2(\text{SO}_4)_3$ ¹				With Added $\text{Fe}_2(\text{SO}_4)_3$ ²			
	General Corrosion (mpy)	Pitting (growth of deepest pit in mpy)	Crevice (growth rate in mpy)	Comments	General Corrosion (mpy)	Pitting (growth of deepest pit in mpy)	Crevice (growth rate in mpy)	Comments
Low Alloy Iron Base								
Mild Steel (1010)	>14.3	--	--		--	--	--	
Gray iron	8.0	--	--		>78	--	--	Matrix destroyed (graphitized)
3% Ni Gray iron	8.4	--	--		--	--	--	
Ductile iron	14.3	--	--		>73	--	--	Matrix destroyed (graphitized)
Type 2 Ni-resist	0.9	5.6	4.3		> 7.6	--	--	some graphitization
Cor-Ten	--	--	--		16.8	--	--	broad depressions
Stainless Steels								
Type 304	< 0.1	--	incip.		0.7	9.3	--	
Type 304 (sensitized)	--	--	--		0.9	15.5	3.1	extensive pitting
Type 316	< 0.1	--	--		< 0.1	--	--	
Type 316 (sensitized)	--	--	--		< 0.1	3.7	--	
Type 409	0.2	27.8	27.8	perforations ³				
Type 410	0.1	22.3	5.6	perforations ³	3.4	>40	3.7	perforated ³
Type 430	0.3	19.2	19.2	perforations ³	3.5	>40	0.6	perforated ³
Carpenter 20Cb3	0.1	--	incip.		0.1	--	--	
17-4PH	--	--	--		< 0.1	--	--	
CF 8 (cast)	< 0.1	--	4.9		--	--	--	
CF 8M (cast)	< 0.1	--	--		--	--	--	
Copper Base								
Admiralty Brass	--	--	--		--	--	--	
90-10 CuNi	--	--	--		--	--	--	
10 Al-5 Ni Bronze	0.1	--	3.7		--	--	--	
Aluminum Base								
Alcoa 1100	--	--	--		0.8	15.5	3.7	broad pit attack
Alcoa 2024	--	--	--		0.6	27.2	5.6	broad pit attack
Alcoa 3003	--	--	--		0.8	5.6	8.0	broad pit attack
Alcoa 6061	0.1	11.1	10.5		0.9	10.5	4.3	broad pit attack
Nickel Base								
Monel 400	2.1	--	--		0.4	4.9	incip.	

¹Exposure = 590 days²Exposure = 585 days³Observed at end of test**Test conditions:**

Specimens immersed in hot well fluid. No quantitative data on the fluid are available but it is aerated and contains CO_2 , H, S, NH_3 , and possibly traces of Cl^- .

Test conditions:

Same as "Without $\text{Fe}_2(\text{SO}_4)_3$ ", except that 30 ppm iron as $\text{Fe}_2(\text{SO}_4)_3$ was added for H_2S abatement.

TABLE A-9 (Continued)

CORROSION STUDY IN THE BAROMETRIC CONDENSERS AT THE GEYSERS, CA

	Without $\text{Fe}_2(\text{SO}_4)_3$ Addition ¹				With $\text{Fe}_2(\text{SO}_4)_3$ Addition ²			
	General Corrosion (mpy)	Pitting (growth of deepest pit in mpy)	Crevice (growth rate in mpy)	Comments ³	General Corrosion (mpy)	Pitting (growth of deepest pit in mpy)	Crevice (growth rate in mpy)	Comments ³
Low Alloy Iron Base								
Mild Steel (1010)	> 6.2	--	--	Specimen gone	--	--	--	
Gray iron	< 3.6	--	--	Graphitized	> 73	--	--	Completely graphitized
3% gray iron	< 3.8	--	--	Graphitized	--	--	--	
Ductile iron	< 5.8	26.5	--	Broad pits	> 78	--	--	Matrix destroyed (graphitized)
Type 2-Niresist	< 2.7	4.0	--	Broad shallow depressions	> 5	--	--	Partially graphitized
Cor-Ten	--	--	--		--	--	--	
Stainless Steels								
Type 304	< 0.1	1.1	none		> 10.8	--	--	
Type 304 (sensitized)	< 0.1	3.2	1.1		0.3	--	--	
Type 316	< 0.1	none	none		1.4	--	--	
Type 316 (sensitized)	< 0.1	0.3	1.9		< 0.1	--	--	
Type 409	< 0.1	5.3	3.7		< 0.1	6.9	3.1	Pits on edge
Type 410	< 0.1	9.5	perf.	Crevice perforated sample	--	--	--	
Type 430	< 1.0	perf.	perf.	Numerous perforations	2.4	738	incip.	Perforated
Carpenter 20Cb3	< 0.1	none	none		2.2	30.5	incip.	Perforated
17-4 pH	< 0.1	1.6	none		< 0.1	--	--	
CP-8 (cast)	< 0.1	none	1.1		0.1	--	--	
CP-8M (cast)	< 0.1	none	none		--	--	--	
Aluminum Base								
Alcoa 1100	--	--	--		0.9	12.5	6.2	Broad pit attack
Alcoa 2024	< 0.4	6.6	perf.		15	> 31	11.8	Perforated, broad pit attack
Alcoa 3003	--	--	--		1.3	19.9	8.7	Broad pit attack
Alcoa 6061	< 0.1	1.32	4.0		5.5	18.7	7.5	Broad pit attack
Copper Base								
90-10CuNi	--	--	--		14.4	--	--	
Admiralty Brass	--	--	--		19	24.3	13.7	
10Al-5Ni Bronze	< 1.8	--	--		--	--	--	
85-5-5-5 Bronze	< 1.6	--	--	General attack	--	--	--	
Nickel Base								
Monel 400	< 5	--	--		1.6	--	--	

¹Exposure = 586 days²Exposure = 1378 days³Observation made at end of test

TEST CONDITIONS:

Specimens exposed to washing-misting conditions near top of barometric condenser. No quantitative data on the test media is available, but consists of steam condensate and aerated cooling water. It contains CO_2 , H_2S , SO_4 , and traces of Cl^- .

Similar to "without iron addition" except that 30 ppm iron as $\text{Fe}_2(\text{SO}_4)_3$ was added for H_2S abatement.

Reference: CE-119

A.3.2 Discussion of Results

Type 316, Carpenter Alloy 20Cb-3, and 17-4 PH stainless steels experienced minimal corrosive attack. Sensitized Type 316 showed some pitting in recirculating aerated condensate with $\text{Fe}_2(\text{SO}_4)_3$ addition. Type 304 exhibited significant pitting in both the sensitized and solution annealed conditions. Both the general corrosion rate and rate of pit penetration of Type 304 increased significantly with time. Ferritic stainless steels such as Types 403, 409, 410, and 430 had such high pitting rates that they were not satisfactory in The Geysers condensate system. The corrosion rate of Type 430 increased with time.

The ductile, gray, and Ni-resist cast irons and high corrosion rates. The matrix tended to graphitize and/or dissolve. The remaining material looked sound but could not withstand any load.

Carbon steel (1010) had an extremely high corrosion rate and was not suitable for use in contact with The Geysers condensate.

Aluminum alloys were unsuitable for use in condensate because of excessive pitting, especially when $\text{Fe}_2(\text{SO}_4)_3$ was added.

Copper alloys suffered severe sulfide attack before $\text{Fe}_2(\text{SO}_4)_3$ was added. Addition of iron tended to reduce corrosion of copper alloys when the specimens were completely submerged and increased corrosion when they were not completely submerged.

A.3.3 Turbines - Design Change

Thirteen of the fifteen power units at The Geysers were provided by Toshiba Turbines. Turbine blades, shrouds, and stays are Type 410 stainless steel. Early turbine blade problems indicated erosion-corrosion of the blades and cracking of the stays.

The turbines were redesigned mechanically. Blade passing velocity was reduced and the blade root was thickened for increased strength. Problems were significantly reduced by these changes with no change in materials (personal communication with PG&E personnel). Corrosion fatigue, possibly induced by chloride pitting, was cited as the probable cause of these problems (SH-334).

A.3.4 Electrical Equipment

Attack on copper and silver switch contacts by atmospheric H_2S has been a major problem at The Geysers. This problem is being solved by replacing all copper, copper alloy, or silver contacts with corrosion-resistant contacts as they are due for servicing. Terminals are dipped in solder and switch contacts, relay points, etc. are being cadmium plated. This approach seems to be satisfactory at The Geysers (personal communication with PG&E personnel).

APPENDIX B
CORROSION IN SEAWATER
DESALINATION PLANTS

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 120°C. 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 120°C is normally pretreated to remove CO₂ and then adjusted to about pH 7. Many geothermal fluids have high CO₂ concentrations and pH less than 7. 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 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-1.

TABLE B-1
NORMAL SEAWATER

<u>Component</u>	<u>Concentration</u>	
	<u>ppm</u>	<u>gm/liter</u>
Sodium (Na)	10768	11.035
Magnesium (Mg)	1298	1.330
Calcium (Ca)	408	0.418
Potassium (K)	388	0.394
Chloride (Cl)	19361	19.841
Sulfate (SO ₄)	2702	2.769
Bicarbonate (HCO ₃)	143	0.146
Total Solids	35175	36.047

Reference GE-117

B.1 Corrosion Results

The results of corrosion tests in desalination facilities are discussed below for several metals.

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 (GE-117).

B.1.2 Copper-Based Alloys

Uniform corrosion data for 12 copper alloys tested at the OSW Materials Test Center are presented in Table B-2. 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-3 shows the results of impingement corrosion. Destruction of the CuO film will cause all copper alloys to pit under deposits or where the seawater velocity is greater than 8 fps. H_2S and NH_3 (or NH_4^+) greatly increase the pitting of copper alloys. Alloys 433 and 687 undergo stress corrosion cracking and become major hazards if exposed to NH_3 , NH_4^+ , or Hg. Alloy 706 is a minor stress corrosion cracking hazard under these conditions. Brasses with more than 15 percent zinc must be inhibited with arsenic or antimony to prevent de-alloying (GE-117).

TABLE B-2

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 ² 104°C O ₂ = 0 ppb	Concentrated Brine Recycle ³ 104°C O ₂ = 0 ppb 35,000 ppm TDS	Brine Heater Section ³ 121°C O ₂ = 0 ppb 29,000 ppm TDS	Oxygenation Study ⁴ Concentrated Brine (35,000 ppm TDS)					
				45°C O ₂ = 75 ppb No Fe Added		65°C O ₂ = 65 ppb No Fe Added		79°C O ₂ = 60 ppb No Fe Added		90.5°C O ₂ = 47 ppb No Fe Added		99°C O ₂ = 35 ppb No Fe Added					77°C		104°C			
Designation	Alloy No.	Method of Manufacture	Temper	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*	Fe Added*			O ₂ = 20 ppb	O ₂ = 100 ppb	O ₂ = 200 ppb	O ₂ = 20 ppb	O ₂ = 100 ppb	O ₂ = 200 ppb	
Pure Copper	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	HR	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
Arsenical Admiralty Brass	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	—	—	—	—	—	
Arsenical Aluminum Brass	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	1.7-3.9	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	—	—	—	—	—	—	—	—	
9/10 Cu/Ni	706	S	LD	—	—	—	—	—	—	—	—	—	—	0.40	0.42	1.4	—	—	—	—	—	
	706	S	HD	—	—	—	—	—	—	—	—	—	—	0.55	0.30	1.8	—	—	—	—	—	
	706	SW	HR	—	—	—	—	—	—	—	—	—	—	0.60	0.31	—	0.15	0.5	0.4	0.3	0.9	0.8
	706	SWW	HR	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	—	—	—	—	—	—	—	—	
70/30 Cu/Ni (.4-.7 Fe)	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	—	—	0.8	—	—	—	—	—	
70/30 Cu/Ni (1.8-2.2 Fe)	715 mod	S	A	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
	716	S	A	—	—	—	—	—	—	—	—	—	—	—	—	1.4	—	—	—	—	—	
	720	S	A	—	—	—	—	—	—	—	—	—	—	—	—	1.1	—	—	—	—	—	

Feed was controlled at pH=7.4 and O₂=75ppb

S = seamless

SW = seam welded

SW = butt welded

A = annealed

HR = half hard

LD = light drawn

HD = hard drawn

Source: GX-117

¹Values are results of two trials of 5 months each.²Tubes pulled after 29 months exposure.³Tubes pulled after 34 months exposure.⁴90 days exposure.⁵Added as FeSO₄. 0.1 ppm ferrous ions have been

shown to reduce general corrosion by 50%. A

sacrificial length of iron pipe in the intake

system could provide sufficient ferrous ions.

TABLE B-3
IMPINGEMENT CORROSION OF COPPER ALLOYS
AT THE OSW TEST CENTER

<u>Copper Alloy</u>		<u>Impingement Corrosion (mpy)</u>	
<u>Designation</u>	<u>Alloy No.</u>	<u>10 fps</u>	<u>15 fps</u>
Arsenical Admiralty Brass	433	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 121°C is presented in Table B-4. Pitting and crevice corrosion of the low alloy steels were severe, but traces of oxygen (<50 ppb) were present in the flowing seawater and this would facilitate these types of corrosion.

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 and crevice corrosion become major concerns, as does stress corrosion cracking. Table B-5 presents the results of pitting tests on 19 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-4

CORROSION OF LOW ALLOY STEELS IN FLOWING SYNTHETIC SEAWATER

Material	Exposure (days)	Velocity (fps)	Uniform Corrosion (mpy)	Pitting Attack*	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

*Qualitative data only. No definition of descriptors.

Test conditions: flowing synthetic sea water, 121°C, pH 6.4-7.9, <50 ppb O₂.

Source: BA-539

TABLE B-5

PITTING CORROSION OF STAINLESS STEEL ALLOYS IN THE AISI
DESALINATION PLANT AT FREEPORT, TEXAS

Pitting Corrosion of Heat Exchanger Tubes (walls 49 mil thick)								
	Heat Recovery Unit 43-93°C		Brine Heater 113-121°C		Brine Recycle Loop 105°C		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 ³	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 ¹	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 ²	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 ¹	6 mo	80 mpy	12 mo	30 mpy	12 mo	12 mpy
Allegheny 444L	12 mo	perforated ²	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

¹Perforation occurred after less than 6 months exposure.

²Perforation occurred after 6 months, but before 12 months exposure.

³Perforation occurred after 12 months, but before 18 months exposure.

Note: The seawater feed to the heat recovery unit was controlled with pH = 7.0, O₂ = 25 ppb and CO₂ = 1 ppb.
Most of the dissolved O₂ was probably consumed in the Heat Recovery Unit.

Source: GE-117

APPENDIX C
PRELIMINARY COMPARISON OF GEOTHERMAL
FOSSIL FUEL GENERATING PLANT AVAILABILITY

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 D

GEOTHERMAL ELASTOMERIC MATERIALS

GEOTHERMAL ELASTOMERIC MATERIALS

The Department of Energy is conducting research to develop elastomers for geothermal use. Five research programs are involved in various phases of the development and testing of elastomers for use in geothermal wells. The goal is to seek new materials and tests which will serve in geothermal applications. Of particular interest are packer seals and drill bit cutter cone seals. The approaches range from basic research to applied development and include synthesis of new polymers, investigation of new but available (at high cost) elastomers, modification of commonly known materials and development and evaluation of test methods.

Results of these ongoing research programs are described below. Each program, conducted by an individual contractor, has different goals and test methods; therefore, results are grouped according to research program.

D.1 Elastomer O-Ring Seal Program

The object of this study was to test commercial elastomeric materials for potential application as O-ring seals in geothermal environments. The O-rings were either reed oval configurations or #2-329 types. The critical properties desired in the elastomers were:

- 1) low compression strength of less than 20%,
- 2) good abrasion resistance and high tear strength,
- 3) resistance to attack from petroleum-based

lubricants, common mud additives, H₂S, and moderate shifts in pH, and

- 4) retention of the above properties at elevated temperatures.

D.1.1 Test Program

The test program investigated the influence of the following variables on the performance of elastomers in geothermal drilling operations:

- 1) temperature of geothermal formation and from friction,
- 2) rotational eccentricities of drill cutter cones ("wobbling" on the lug),
- 3) abrasive particles, and
- 4) chemical composition of the geothermal brine, especially H₂S which causes brittleness in elastomers by creating unwanted cross-links.

D.1.2 Materials Tested and Results

1) Buna-N (Parker #N4187) performed well between 100°C-200°C with no abrasives present. The temperature limit was approximately 225°C. Preheating of the seal to 50°C before use increased lifespan, but preheating to 240°C and 260°C, then cooling to 175°C prior to drilling resulted in extensive seal damage and poor performance. Test time: 4 hours simulated drilling.

2) Ethylene-Propylene (Parker #34183-80A) gave poor performance at 200°C (only temperature tested). Deterioration resulted when petroleum-based lubricants were used. Time: 4 hours.

3) Fluorocarbon elastomers from DuPont's Viton and 3M's Fluorel (Parker #V747-75A) were tested. Pre-warming of the seal to 50°C was beneficial. Ultimate usable temperature was 235°C. Results were good with or without the presence of abrasives. Fair results were obtained when seals were heated, then cooled, to simulate "tripping" into a hot well. Time: 4 hours.

4) Fluorosilicone Rubber (Parker #L4216-70A) severe breakdown occurred between 175°C-200°C. Brittle failure occurred via deep cracks and pitting of the running surfaces. Molecular degradation was indicated throughout the material. Time: 4 hours at 200°-260°C with no abrasives; 1 hour at 175°C with abrasives.

5) Test results were incomplete for Firestone PNF-200, a fluoronated polyphosphazene rubber. Failure occurred after testing at 200°C with no abrasives. Molecular degradation was indicated. Time: 4 hours.

6) Test results were incomplete for Kalrez #1050-70A, a perfluorelastomer. Compression set resulted in failure to maintain a seal. There was no apparent molecular degradation at 200°C. Time 4 hours.

7) Modified Buna-N gave poor results. Excessive frictional heating resulted in breakdown of the elastomer at the seal surface. Tests were conducted at 200°-225°C. Time: 4-6 hours.

Test results are summarized in Table D-1.

D.2 Downhole Packer Seal Program

The objective was the development of elastomers for downhole geothermal seals. The applications are for use as casing packer seals.

D.2.1 Test Program

Simulation (SIM) Tests were designed to provide a good simulation of the casing packer seal operational environment in the laboratory. The SIM apparatus applies all environmental stresses simultaneously, i.e., fluid pressure, differential pressure, temperature, mechanical forces, and brine chemistry, to a full scale packer seal. The synthetic geothermal fluid was formulated to contain: H_2S -300 ppm; NaCl -25,000 ppm; CO_2 -1,000 ppm; H_2O -balance. Elastomers were tested in this synthetic geothermal fluid at 260°C and up to 5000 psig. Test duration was 24 hours or until seal failure.

D.2.2 Materials Tested and Results

Five companies supplied the following types of elastomers: Buna-N (Nitrile), Ethylene Propylene Terpolymer (EPDM), Viton, and Epochlorohydrin. Several different formulations of each were tested. The results are summarized in Table D-2.

D.3 Casing Packer Development Program

The objective of the program was to develop a material as a casing packer for use at 260°C , 1500 psia, for 24 hours in a geothermal environment. The casing packer should be thermally

TABLE D-1
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)	At least 6 Co.'s	Butadiene & acrylonitrile	150°C (300°F)	Low	High temp water and steam	Low temp limit
Ethylene-propylene	At least 5 Co.'s	Ethylene-propylene	180°C (350°F)	Low	Petroleum base fluids	None
Viton	Du Pont	Fluorocarbon	260°C (500°F)	Low	High temp water and steam	Tear resistance
Fluorosilicone	Dow Corning	Fluorosilicone	260°C (500°F)	Low	Silicone lubes, water and steam	Tear & abrasion resistance; etc.
PNF-200	Firestone	Phosphonitrilic Fluoroelastomer	200°C (400°F)	\$100	None expected	Unknown
Kalrez	Du Pont	Perfluoroelastomer	260°C (500°F)	\$2000	None	Unknown
5AD-7004	Custom Rubber Products	Modified Buna N	230°C (450°F)	Low	None	Unknown
Viton, Peroxide-Cured	DuPont/Parker	Fluorocarbon	260°C (500°F)	Low	High temperature water and steam	Tear resistance
TR-70	Dow Corning	Fluorosilicone (clear)	260°C (500°F)	Low	Silicone lubes, water and steam	Tear resistance

From Hendrickson, R.R. et al. "Annual Report. Support Research for Development of Improved Geothermal Drill Bits." ERDA Contract #(10-1)1546, Terra Tek, Inc. Salt Lake City, Utah (June 1977).

TABLE D-2
SIM TEST SUMMARY

Sequence No.	Specimen No.	Compound	Duration Hrs:Min	Inches Extrusion	Set Temp. °C	Diamet. Gap, Mils	Configuration
1	215-3	VT-R-4590, Austin 70 phr	5:52	Nil	260	13	Flat
2	215-2	VT-R-4590, Austin 70 phr	:07	Nil	260	13	Flat
3	A-3	Nitrile	24:	Nil	149	13	Flat
4	A-2	Nitrile	24:	Nil	149	25	Flat
5	A-6	Nitrile	11:	0.5	260	175	Flat
6	213-3	VT-R-4590, Asbestine 3X	:00	Nil	260	175	Flat
7	220-3	VT-R-4590, Austin 65 phr	:00	Nil	260	175	Flat
8	216-2	VT-R-4590, Kevlar	:00	Nil	260	175	Flat
9	105-II-1	Viton GH, Austin/MT	:05	Nil	260	175	Flat
10	216-1	VT-R-4590, Kevlar	:00	<0.1	260	175	Chamfered
11	A-5	Nitrile	24:	1.75	260	175	Chamfered
12	105-II-2	Viton GH, Austin/MT	:47	Nil	260	175	Chamfered
13	B-3	EPDM	24:	3.75	260	175	Chamfered
14	217-2	EPDM	24:	2.5	260	175	Chamfered
15	C-4	Nitrile	1:13	4.5	260	175	Chamfered
16	D-3	Epochlorohydrin	:00	N/A	260	175	Chamfered
17	E-3	Viton	3:44	No Meas.	260	175	Chamfered
18	222-3	VT-R-4590, Austin 40 phr	:03	0.75	260	175	Chamfered
19	221-2	VT-R-4590, Maglite K	:38	0.75	260	175	Chamfered

From Hirasuna, A.R., et al. "Geothermal Elastomeric Materials. Twelve Month Progress Report." Contract #EG-77-03-1308, L'Garde, Inc., Newport Beach, CA, 1977.

stable in a geothermal environment with 400 psi tensile strength and at least 50% elongation.

D.3.1 Test Methods

Stress relation measurements, sol-gel determinations, swollen stress-strain measurements, weight-loss tests, and tensile tests were conducted after exposure to three solutions at elevated temperatures. The three solutions were saline carbon dioxide solution (solution #1; 2.5% NaCl, 1000 ppm CO₂), saline hydrogen sulfide (solution #2; 2.5% NaCl, 300 ppm H₂S), and deionized water (solution #3).

D.3.2 Materials Tested and Results

The materials tested were:

- 1) Viton 10, 10K, 10G (du Pont)
- 2) Kalrez 3065, 3050 (du Pont)
- 3) AFLAS 150H (Asahi Glass, Yokohama, Japan)

Table D-3 summarizes the mechanical properties of aged elastomers, and Figure D-1 shows the effect of aging on the tensile strength of the elastomers. Results of the elastomer classes are given below.

1) Viton — Viton-10G underwent less oxidative degeneration during stress-relaxation tests than the other Viton formulations. Substantial cross-linking was observed in all formulations. Cross-link densities did not decrease noticeably in any formulation when sol-gel measurements were made. Weight-loss

TABLE D-3

MECHANICAL PROPERTIES OF AGED ELASTOMERS

	TENSILE STRENGTH PSI, AND (ELONGATION %) AT 260°C									
	Unaged Samples	20h at 252°C			40h at 252°C			60h at 252°C		
		Sol. 1	Sol. 2	Sol. 3	Sol. 1	Sol. 2	Sol. 3	Sol. 1	Sol. 2	Sol. 3
Viton 10	250 1470* (18)	220 860* (27)	256 1100* (21)	101 910* (13.5)	14.5 - (18)	26 - (12)	10 - (#)	10 - (10)	13.5 - (12)	5.4 - (#)
Viton 10 K	200 1090* (10)	41 920* (10)	44 850* (#)	- - (-)	30 - (#)	20 - (#)	- - (-)	23.5 - (#)	21 - (#)	- - (-)
Viton 10 G	365 - (22)	14 - (14)	- - -	95 - (16)	8 - (9)	20 - (8)	- - -	- - -	- - -	- - -
Kalrez 3050	278 2470* (58)	269 2515* (53)	250 2330* (52)	152 2000* (33)	296 - (64)	298 - (62)	59 - (12)	263 - (56)	257 - (46)	32 - (10)
Kalrez 3065	280 1840* (32)	187 1780* (57)	211 1680* (56)	138 1400* (36)	202 - (57)	198 - (54)	141 - (37)	195 - (51)	194 - (50)	131 - (35)
AFLAS 150H	246 - (69)	184 - (64)	- - -	120 - (46)	163 - (60)	- - -	85 - (35)	- - -	- - -	- - -

Sol. 1 = 2.5% NaCl + 1000 ppm CO₂; Sol. 2 = 2.5% NaCl + 300 ppm H₂S; Sol. 3 = Deionized water

* Measured at room temperature; # less than 10% elongation at break; - not measured.

From Mueller, et al. "Development and Evaluation of Geothermal Materials. Progress Report I. IAG Contract #E(49-27)-1011, Jet Propulsion Laboratory, Pasadena, CA, October, 1977 (Draft Copy).

Figure D-1. Effect of Aging in Brine (Sol. 1) and Deionized Water (Sol. 3) on Elastomer Compositions

From Mueller, et al. "Development and Evaluation of Geothermal Environmental Materials. Annual Progress Report. 1AG-#(49-27)-1011, Jet Propulsion Laboratory, Pasadena, CA, Oct. 1977. (Draft Report).

measurements after aging in brine solution #1 for 60 hours at 250°C were:

Viton 10 — 9% loss
Viton 10K — 13% loss
Viton 10G — 17% loss

Mechanical properties (tensile/elongation strength) were low for the Vitons after 40 hours in each of the three test solutions.

2) Kalrez — In stress relaxation studies, Kalrez 3050 and 3065 behaved similarly to Viton 10G, except that both were more thermally stable than the Vitons. Cross-link densities did not appreciably decrease when sol-gel measurements were made. Weight-loss measurements in solution #1 for 60 hours at 250°C were:

Kalrez 3050 — 2% loss
Kalrez 3065 — 8% loss

After 40 hours in solution #3, Kalrez 3065 retained 50% of initial tensile strength and 100% of initial elongation. In other solutions Kalrez 3050 and 3065 were stable for 60 hours.

3) AFLAS-150H — This polymer was available only in small quantities and was not tested extensively. No stress relaxation or sol-gel measurements were performed on AFLAS-150H. Weight loss in brine solution #1 was 1%. Tensile stability in all three brine solutions was greater than that of the Vitons but less than that of Kalrez 3050 or 3065.

After one year's work, no candidate elastomer appeared to satisfy the objective requirements of the project. Kalrez

3050 appeared to be the best, but it is too expensive to be used in casing packers. AFLAS was better than Viton. Since no commercially available products appear to be satisfactory, new elastomers for high temperature geothermal applications are being synthesized.

D.4 Elastomer Synthesis and Development Program

The objective of this program was the investigation of materials and techniques for production of high temperature- and hydrolytically resistant rubber. Three materials were investigated: 1) carborane-siloxane (Union Carbide), 2) "FASIL", a fluorinated elastomer being synthesized by Hughes Aircraft, and 3) an ethynyl substituted perfluoroalkylene ether elastomer being synthesized by Hughes. The materials were to be used as seals, cable terminations and cable insulations in geothermal well logging instrumentation. Materials tested thus far have been in the developmental stages and have not been formed into anything but 1/4" x 1/8" "buttons".

D.4.1 Results

Various polymers of carborane-siloxane were formulated (Table D-4) and tested for compression set, durometer hardness (an indication of cross-linking), tensile strength/elongation, and hydrolytic stability under pressure. Results of compression set tests for the most promising formulations are shown in Table D-5, along with hardness tests results. Hydrolytic stability test conditions were 24 hours at 275°C and 800 psi. Complete disintegration of the polymer was noted, regardless of formulation used or type of water (tap or distilled). Further work on this compound has been suspended until information regarding its hydrolytic instability can be found.

TABLE D-4
CARBORANE-SILOXANE FORMULATION DATA

Comp. No.	Date	Polymer		Reinf.		Stabilizer		Cure Agent		Cure Schedule		Post Cure		Hardness	
		Type	gm	Type	gm	Type	gm	Type	gm	Temp °F	Min.	Temp °F	Hr.	Orig.	Post Cured
29	6-27	CBS Fluorel LVS-76	50 50	Tullanox MgO	15 35	Fe ₂ O ₃ CaO	6.5	None	None	340°	30, 60, 90, 120	-	-	did not cure	
30	6-28	CBS Fluorel LVS-76	75 25	Tullanox MgO	15 35	Fe ₂ O ₃ CaO	6	None	None	340°	30, 60,	-	-	did not cure	
31	7-7	CBS	100	Tullanox MgO	15 20	Fe ₂ O ₃	5.0	Varox	2.0	340	30	-	-	45	Soft and sticky
32	7-7	CBS	100	Tullanox MgO	15	Fe ₂ O ₃	2.5	Varox	2.5	340	30	-	-	40-50	Sticky
33	8-1	CBS	100	Tullanox MgO	13.3 31.9	Fe ₂ O ₃	8.3	Vulcup	3.75	340	30	450° 525	48 48	53.3	70 79
34	8-1	CBS	100	Tullanox MgO	5.87 14.3	Fe ₂ O ₃	12.5	Vurox	12.5	340	30	450° 525	48 48	52.6	61 72
35	8-9	CBS	100	Tullanox MgO	5.87 14.3	Fe ₂ O ₃	12.5	Vulcup	3.75	340	30	450° 525	48 48	42.5	45 49
36	8-9	CBS	100	Tullanox MgO	20 50	Fe ₂ O ₃	12.5	Vulcup	3.75	340	30	450° 525	48 48	48.2	60 63
37	8-9	CBS	100	Tullanox MgO	20 50	Fe ₂ O ₃	12.5	Varox	12.5	340	30	450° 525	48 48	56	67 70

TABLE D-5
COMPRESSION SET TESTS

Formulation	Curing Agent		Filler		Final Hardness		Comp. Set %
	Type	%*	Type	%	525°	575°	
33	Vulcup	3.75	Tullanox MgO	13 32	70	79	93-100
34	Varox	12.5	Tullanox MgO		61	72	98
35	Vulcup	3.75	Tullanox MgO	5.87 14.3	45	49	122
36	Vulcup	3.75	Tullanox MgO	20 50	60	63	81
37	Varox	12.5	Tullanox MgO	20 50	67	70	100
*Percent by weight of base polymer							

Hughes synthesized a fluorinated elastomer ("FASIL"), but no materials testing has been done on this material; work has stopped in this area because of the hydrolytic instability of siloxane-type polymers.

Synthesis of perfluoroalkylene ether elastomers is continuing, but no satisfactory material has yet been developed

D.5 Program to Develop and Evaluate Elastomers

The objectives of the program were 1) to develop and evaluate coating processes for elastomers to be used in deep wells, and 2) to evaluate commercial elastomers for use in a geothermal borehole logging tool. Application potentials were for elastomeric material in general, but Kalrez O-rings received specific attention.

Kalrez, a perfluorinated elastomer from DuPont has good potential for deep well application because of its high thermal stability and chemical resistance. Its usefulness (especially in packer manufacture) is limited by its high cost: \$2000/lb.

D.5.1 Test Program

The following elastomers were coated with a 400 Å-thick coating of cross-linked poly (tetrafluoroethylene) using an RF Glow Discharge apparatus: 1) Kalrez (DuPont) 2) Fairprene BS-5565 (Buna-N, DuPont); 3) Buna-N (Parker); 4) Viton V-747-75 (Parker). Samples were aged in a sour gas (composition not provided) environment for one month at 200°C.

D.5.2 Results

Both coated and uncoated samples of Kalrez were stable under the test conditions. Coating of the Buna-N rubbers with cross-link Teflon did not prevent or minimize degradation which may have been caused by heat alone. Chemical resistance of Viton rubber appeared to be enhanced by the plasma coating. An air leak during the test may have been responsible for the poor Buna-N performance.

A Kalrez O-ring seal was exposed to steam for 100 hours at 275°C and 4800 psi. Experimenters report only that it "failed catastrophically".

APPENDIX E
COMPARATIVE ALLOY COSTS

COMPARATIVE ALLOY COSTS

Table E-1 lists the comparative costs of ten common construction alloys. The costs of the alloys are normalized and compared to AISI Type 304L stainless steel, a widely-used alloy. All values in Table E-1 are comparative values ratioed to 1.00 for Type 304L and do not represent actual dollar values. The comparative costs in Table E-1 were assembled after examining available information and talking to alloy suppliers.

The alloy cost comparisons in Table E-1 are based on the same dimensions of bulk metal sheet for each alloy. This does not take into account the factors involved in fabricating an alloy for a particular application. Some corrosive environments may require such a thicker plate of lower cost, less resistant alloy that using a normally more expensive but resistant alloy will actually result in lower initial costs because a much thinner plate can be substituted.

TABLE E-1
COMPARATIVE COSTS OF SOME ALLOYS

<u>Alloy</u>	<u>Approximate Relative Cost per sq ft of $\frac{1}{4}$ inch plate*</u>
Carbon Steel	0.25
AISI Type 304L	1.00
AISI Type 316L	1.25
90-10 Cupronickel	2.13
Ti-50A (Grade 2)	2.50
70-30 Cupronickel	2.50
TiCode 12	3.00
Monel 400	3.50
Inconel 600	3.88
Ti-0.2 Pd (Grade 7)	5.00

*Cost relative to cost of 1 sq ft of $\frac{1}{4}$ -inch Type 304L plate.
Based on late 1976 prices.

APPENDIX F

PRELIMINARY LIST OF AVAILABLE GEOTHERMAL POWER EQUIPMENT

PRELIMINARY LIST OF AVAILABLE GEOTHERMAL
POWER EQUIPMENT

Table F-1 is a preliminary list of suppliers of geothermal equipment. The list includes firms that responded affirmatively to an initial survey directed toward identifying firms that manufacture equipment specifically for geothermal applications. This list is not intended to be all-inclusive and is for those groups who may need to know potential manufacturers but who do not have access to such vendors through normal channels. The list is only a starting point in identifying the equipment that may be needed to utilize a geothermal resource.

TABLE F-1

PRELIMINARY PART-SUPPLIER LIST OF GEOTHERMAL EQUIPMENT

<u>Parts or Services</u>	<u>Manufacturer*</u>	<u>Specialty</u>
Compressors	The Nash Engineering Co.	Instrument air, 0-300 CFM, 125 psi
Controls and Instruments	Fox Valve Development Co. Kinemetrix Inc. Leeds and Northrup Co.	Venturi controls and flowmeters Seismic monitoring instruments Controls and instruments for power generation
Electrical Equipment	Cutler-Hammer, Inc. The Ideal Electric Co. The Lima Electric Co. Dept TC Louis Allis Marathon Electric McGraw-Edison Rauland Electric Co. Temco, The Electric Materials Co.	Motor controls and switchboards Large motors, generators, controls Specialty motors to 11,000 HP 1800 RPM generators, 50 60 1100 kw Station step-up transformers Specialty motors, controls, packaged drives Bus systems, specially fabricated parts
Piping	American Cast Iron Pipe Co. National Tank and Pipe Co. Northwest Pipe and Casing Co. Wolf Ridge Plastics	Polybond-lined ductile iron piping Wood piping Steel pipe, 2-120" dia Plastic piping and vessels
Plant Design, Construction and Installation	Brown Boveri Corp. Research-Cottrell Inc. Technical Enterprises, Inc. DeDietrich (USA), Inc.	Complete turnkey power plant, all components on non-turnkey basis Total flow skid mounted systems, 2-4 MWe
Pressure Vessels	APV Company, Inc. B&W C-E Lummus C-E Natco Ceilcote Company Croll-Reynolds DeDietrich (USA), Inc. Econ-Therm Energy Systems Corp. Poly Processing Co. Stearns-Roger, Inc. Thermxchanger, Inc. Wyatt Industries	Plate type heat exchangers in stainless steels, titanium, Incolloy Heat exchanger equipment Heat exchanger equipment Separators and water filters Pressure vessels, piping, air pollution control equipment Filter systems Glass-lined steel vessels, pipes and fittings Heat exchangers from carbon steel and stainless alloys Large vessels and structures of high density polyethylene Medium-large plate fabrications, heavy machine work Tube and shell heat exchangers Pressure vessels and heat exchangers, all weldable metals
Pumps	Allis-Chalmers Corp. The Nash Engineering Co. Worthington Pump Corp. (USA)	Large centrifugal pumps Vacuum pumps, 0-9000 CFM, 3-27" Hg Downhole, jet, hydraulic driver pumps
Turbine Generators	Elliot Co. Turbodyne Corp.	Steam and binary vapor turbine generators Steam generators
Valves	Kamyr Valves, Inc. Rockwell International, Flow Control Division	Severe service ball and butterfly valves
Wellhead Equipment	PMC Corp. WKM-Wellhead Systems	Wellhead systems Wellhead systems

*Affirmative responses