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**THE LLL GEOTHERMAL ENERGY PROGRAM
STATUS REPORT
JANUARY 1976 – JANUARY 1977**

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PREFACE

The Lawrence Livermore Laboratory's Geothermal Energy Development Program, funded by the U.S. Energy Research and Development Administration, was initiated in January 1974. This report, which is the third major status report, describes significant events and detailed results obtained from January 1976 through January 1977. The timing is purposely chosen to coincide with the completion of several significant laboratory and field experiments. Furthermore, this report serves as documentation of the material presented at a major program review meeting held at Livermore on December 14-16, 1976, and attended by more than 80 industry representatives. The purpose of the meeting was (1) to provide detailed current information on the LLL program content, technical results, and goals; (2) to seek participation from industry in helping review program direction; and (3) to encourage greater industry participation in future work toward the commercialization of our results. It is hoped that this report will further these objectives.

The authors or contributors are identified in the report and in the tables of contents. These are the people who have done the detailed technical work and should be recognized. The editors have produced introductory material for each section and for the report as a whole.

A. L. Austin

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1. PROGRAM DESCRIPTION

1.1 Background

At the Lawrence Livermore Laboratory (LLL) interest in geothermal energy started in the early 1960s as part of the Plowshare Program and because of associated work in the earth sciences. In 1972, the Laboratory established programs to develop nonnuclear alternative energy supplies in response to urgent national needs to achieve energy independence in the 1980s. As part of this effort, the LLL Geothermal Energy Development Program began in January 1974 with the objective of developing the total flow concept with specific application to California hydrothermal resources, assessing the potential for utilizing the geopressured resources of the Gulf Coast region, and assessing the potential for nonelectrical uses of geothermal energy in the United States.

The latter two efforts have been completed with the conclusion that the development of geopressured resources and nonelectrical uses of geothermal energy is largely and properly an industrial function. Consequently, the LLL geothermal program has since been focused on the development of advanced technologies uniquely needed for the utilization of water-dominated hydrothermal resources, with emphasis on solving the

extremely difficult problems entailed in utilizing the so-called high-temperature, high-salinity (HT/HS) resources of California. This consists generally of the development of advanced energy-conversion systems, such as those based on the total flow concept, with strong emphasis on a system approach that necessarily depends on solving the problems of scale formation, corrosion/erosion of materials, spent-brine disposal and solids handling, and the development of reliable, efficient energy-conversion systems.

Much of this work has general applicability to other resource utilization concepts and to other resource areas. Consequently, in FY 1976, the Laboratory established—at the request of the U.S. Energy Research and Development Administration (ERDA)—an Industrial Support Program (ISP) to provide technical assistance to joint ERDA/industry projects on the utilization of high-temperature, high-salinity geothermal resources in the Imperial Valley, California. The LLL program is now in transition from emphasis on applied research to one of development and involvement with field demonstration programs.

1.2 Project Rationale

A key element in the rapid commercialization of geothermal energy is the early development of the hydrothermal resources. They are abundant, their exploitation represents the next technological step, and systems developed for hydrothermal resource utilization will be applicable to other, potentially larger, resources such as the geopressured and the hot, dry rock forms.

Of particular significance are the identified hydrothermal resources in the Salton Trough geologic province. This region contains six identified known geothermal resource areas (KGRA) in the U.S. territory alone. Just south of the U.S./Mexican border, in the same geological setting, a 75-MW flashed-steam plant has been operational since 1973. The entire region is perhaps the best known and characterized water-dominated hydrothermal resource in

the North American Continent. Among the six KGRAs in the United States, the Salton Sea Geothermal Field in the Salton Sea KGRA (SSKGRA) is the best known: 23 wells have been drilled and produced, geophysical data have been gathered, and considerable private funds have already been invested in terms of capital for wells and costs of leaseholdings. Hence, in terms of setting priorities for accelerating the development of geothermal energy, the Salton Trough resources appear to be prime candidates, with the Salton Sea Geothermal Field leading as the largest potential energy source.

According to the U.S. Geological Survey (USGS Circular 726), the SSKGRA is the highest temperature and the third largest KGRA; it is capable of producing 83,600 MWe-yr, which is 10% of the

total electrical energy recoverable from the large high-temperature hydrothermal resources (including dry steam resources) in the United States. However, the two largest KGRAs (Long Valley and Coso Hot Springs) are undrilled, and estimates of their energy productivity are speculative at best. If these two are dropped from the list of candidates for early development, the SSKGRA could provide up to 17% of the energy recoverable from the total U.S. hydrothermal resources. Furthermore, it is estimated that over half the energy recoverable from the Salton Trough resides in the SSKGRA.

The 83,600 MWe-yr of electrical energy recoverable from the SSKGRA is equivalent to replacing about 1 billion barrels of oil (or its coal equivalent) for electricity generation. This is fuel that, if not burned in western power plants, could be utilized elsewhere.

In summary, the reasons for high-priority development of the SSKGRA resource are as follows:

1. It is the best known KGRA.
2. It is the hottest (300°C) geothermal resource

1.3 Objectives

The LLL Geothermal Energy Development Program is directed specifically to solving the problems unique to the SSKGRA. Hence the basic objective of the program is to carry out the research and development necessary to produce the needed advanced technologies and to reduce the technical risks sufficiently to encourage and accelerate commercial development. The program is structured to include strong industry involvement through technology transfer and joint ventures in time to stimulate commercialization in the 1980s. To accomplish this, the program consists of two basic activities.

Technology Development

The technology development activity consists of an interdisciplinary approach to the development of efficient, reliable brine-tolerant conversion systems uniquely designed for the high-temperature brines of the SSKGRA, which may have a total dissolved solids content of as much as 30% by weight. The emphasis is on development of the

and hence has the potential for producing the lowest energy costs.

3. It has the potential for producing 83,600 MWe-yr of electricity and replacing about 1 billion barrels of oil.

4. It is close to major West Coast loads.

5. It has a high dissolved-solids content—a type of resource for which new technologies are needed.

The last point is especially important since it provides one of the main reasons for LLL involvement. Probably more than 90% of this region is already under private lease, but among the major barriers preventing rapid development are the serious technical difficulties posed by the presence of large quantities of total dissolved solids (as much as 30% by weight in some areas). Scale formation and control, corrosion, solids handling and control, efficient and reliable conversion methods, and spent-brine disposal are all problems compounded by the presence of high temperature and high total dissolved solids—and the resultant constraints on choices of conversion systems for the utilization of this important resource.

total flow conversion system and on solving the problems of scale formation, corrosion/erosion, and spent-brine management.

Industrial Support

The purpose of the industrial support activity is to provide technical assistance to joint ERDA/industry geothermal utilization programs to develop the SSKGRA. The emphasis is on applying the expertise and results obtained in the technology development activity to provide technical support, as needed, in solving operational problems and to carry out complementary applied research to broaden opportunities for solving potential problems. Current involvement consists of working with the flash/binary project jointly undertaken by the San Diego Gas & Electric Company and ERDA.

A. L. Austin

2. PROGRAM PLANS AND RESULTS

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2. PROGRAM PLANS AND RESULTS

2.1 Technology Development

The LLL program emphasizes development of the total flow energy-conversion system, with significant effort toward solving the scaling, materials, and spent-brine-disposal problems. In principle, the total flow system consists of expanding the total wellhead brine-steam mixture directly through a mixed-phase expander to subatmospheric condensing conditions for maximum energy extraction to drive an electric generator. It has the potential for the highest electrical energy output per unit mass of wellhead fluid. This will result in a corresponding reduction in the number of wells and hence in initial capital costs. In addition, because of the inherent simplicity of design, there are increased opportunities for solving the serious scaling and chemistry problems associated with high-dissolved-solids brines and, perhaps more importantly, for reducing the capital costs of conversion systems.

The development of this system is recognized at the start as a high-risk activity with a high payoff. Three problem areas can be identified:

1. The energy-conversion system.
2. The chemistry of the brine with regard to scale and solids formation and spent-brine disposal.
3. The brine-resistant materials required for the conversion system.

Initially, various machines were considered for the total flow process. The impulse turbine was selected as the most suitable candidate for several reasons, particularly its simplicity. All of the pressure and temperature drop occurs in the stationary and accessible nozzles, allowing cleaning or replacement if scale buildup were to occur. Furthermore, the components downstream of the nozzle, including the highly stressed turbine wheel, operate at a low temperature, say 50°C. Such a temperature is conducive to long-term materials reliability.

Currently, energy-conversion engineering is confined to laboratory development and testing of prototype conversion systems using only "clean" working fluids (liquid plus vapor) typical of high-temperature, high-salinity (HT/HS) wellhead thermodynamic conditions. Tests of a complete total flow impulse turbine system have been completed and verify the analytical performance models, which indicate that existing designs are capable of 38 to 48% engine efficiency. Advanced designs are

capable of up to 70% engine efficiency provided nozzles can be designed to reduce the liquid-droplet sizes below 1 μm . The basic conclusion is that the original research goal of 70% engine efficiency remains credible and appears to be achievable. The significance of this is that the HT/HS resource utilization rate (at 25% total dissolved solids) can be potentially increased to about 0.035 kWh/kg—a substantial improvement.

One of the significant features of the LLL geothermal program is the interdisciplinary approach—combining the disciplines of engineering, chemistry, materials science, and geosciences to produce a complete system. With the exception of energy-conversion engineering activities, the majority of the work is performed in the field, using real brines for testing and evaluating scale-control methods, materials for conversion systems, and techniques for disposing of solids and spent brine. Consequently, the results of this field test program will find broad application to all candidate systems for the utilization of HT/HS brines. For this reason the current results are particularly significant.

We have established that scale deposition can be eliminated by brine acidification. Decreasing the pH from 5.6 at the wellhead to below 4.5 by the addition of about 100 to 200 ppm of hydrochloric acid completely eliminates scaling on nozzles used to expand brine from wellhead (220°C) to atmospheric conditions. Post-test examination of sectioned nozzles subjected to modified and unmodified brines showed that control nozzles scaled at a rate of about 0.025 mm/hr (~ 0.8 in./month) in raw brine, while test nozzles remained clean when exposed to acidified brine. A rough cost analysis shows that acidification with hydrochloric acid will add less than 2 mills/kWh to the cost of the energy produced, indicating that the method will likely prove to be economically feasible as well. Furthermore, there is now experimental evidence that acidification delays the formation of and stabilizes the colloidal suspension of silica in the cooled brine. Thus plugging of reinjection wells by normally occurring suspended solids might be avoided.

In addition, concurrent tests of turbine blade materials subjected to the high-velocity acidified-brine streams exiting from the test nozzles indicate that titanium alloys, particularly Ti-6Al-4V, are

resistant to corrosion/erosion. Although test durations were generally less than 100 hr, the results are encouraging. Field tests will continue through FY 1978 to explore acidification and materials response under a wider range of conditions in order to further verify these initial results or to define the limits of applicability.

The program strategy is shown by the simplified network chart in Fig. 2-1, which indicates that the final goal of the LLL program is to design and field test a 2-MWe brine-tolerant total flow system capable of producing the 0.035 kWh/kg of HT/HS brine. As shown, the energy-conversion work will continue in the laboratory to achieve 70% engine efficiency. If this work is successful, the plan is to combine its results with concurrent field work on scale control and materials selection to design and field test the complete 2-MWe system in FY 1980-1981. Strong industry involvement is planned

as the first step toward technology transfer and the commercialization of the concept if the field tests are successful.

The overall total flow development schedule is presented in Fig. 2-2, which shows that all field and laboratory work is planned for completion by the end of FY 1978, provided access to production and injection wells continues to be available. As already noted, strong industry participation will be sought for the design and construction of the 2-MWe system for field testing.

Although much more work remains to be done, our current view is that the original concept remains credible. Figure 2-3 shows this concept and is included here to illustrate the basic elements of the system. The remainder of this report discusses in detail the current status of the individual activities shown in Fig. 2-2 for FY 1977.

Fig. 2-1. Strategy for total-flow-system development program.

Fig. 2-2. Development of total flow system.

Fig. 2-3. The total flow concept for geothermal energy development.

2.2 Industry Support to Joint ERDA/Industry Program

For the immediate future, the work is aimed primarily at supporting a project jointly undertaken by ERDA and the San Diego Gas & Electric Company at Niland, California. The basic objective of this project is to produce sufficient operational and design data in FY 1978 to allow a decision to proceed with a 50-MWe demonstration plant. The main thrust is directed toward testing and evaluating a hybrid concept consisting of a flashed-steam system and a binary cycle system. The LLL role is primarily to carry out the necessary materials analyses and tests, develop methods for scale control and solids handling, and provide data on back-up or alternative approaches, if necessary.

The first approach is to test and evaluate an advanced double-flash concept utilizing a liquid expander between the separators. This has the potential for improving the economics of double-flash systems and utilizing lower temperature geothermal resources. The second approach is to determine

whether scaling can be prevented in heat-exchanger tubes by brine modification. If the results are positive, the option of returning to the original plan of constructing a conventional binary cycle plant is reopened. Both approaches are directly related to the joint ERDA/San Diego Gas & Electric Company project as options and in addition will provide technologies for other joint ERDA/industry projects in the Imperial Valley. Both schemes, however, have some potential disadvantages due to complexity, size, the costly corrosion-resistant materials necessitated by higher temperature effluents, and potentially high overall costs. The third approach is the total flow concept already discussed.

Because of the nature of the problem, most of the support work lies in the area of brine chemistry, materials, and reservoir assessment and engineering. The detailed work is discussed in the remainder of this report.

2.3 Summary of Results

To date, the major achievements of the LLL Geothermal Energy Development Program have been the following:

- A geothermal test facility has been designed and operated at the Laboratory to simulate the thermodynamic conditions of any hydrothermal well output. This facility is used to test expander components, develop methods for measuring and characterizing two-phase flow, and test and evaluate total flow expanders, with outputs of up to about 100 kW.
- A single-stage total flow impulse turbine has been developed and tested. The results indicate that the original research goal of 70% engine efficiency is achievable. This moves the total flow concept from remote to near-term technology.
- A geothermal field test station has been designed and operated for brine-chemistry and materials studies under field conditions.

The technical and economic feasibility of scale control by brine acidification has been established.

- Brine acidification appears to stabilize the colloidal suspension of solids in cooled brine and to

prevent precipitation. This may have important implications for long-term reinjection without plugging the formation.

- Promising corrosion/erosion resistant alloys for conversion systems have been identified and field tested.

- Techniques for brine sampling, brine characterization, scale surveillance, and field tests of materials have been established and developed.

- Analytical techniques have been developed for advanced two-phase turbine design, two-phase flow, brine chemistry modeling, and multiwell reservoir modeling for production/injection reservoir management.

- A data base has been developed for assessing the high-temperature, high-salinity geothermal resource in the Imperial Valley of California.

- Strong ties with industry have been established via joint projects, cooperative research and development programs, and continual technical interchange.

A. L. Austin

3. ENERGY-CONVERSION ENGINEERING

3. ENERGY-CONVERSION ENGINEERING

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3. ENERGY-CONVERSION ENGINEERING

3.1 Introduction

The effort in energy-conversion engineering has three main objectives:

1. Verify the technical feasibility of energy-conversion concepts both by analysis and by experiment.
2. Complete economic assessment in conjunction with industry.
3. Transfer new technology to industry.

Our work has been strongly directed toward high-temperature, high-salinity (HT/HS) brines. Thus it is especially important that the brine environment be considered in the selection of expanders and in the detailed design of systems. The difficulties inherent in the use of HT/HS brines encourage design simplicity and a choice of operating conditions that will lead to high reliability.

Specialized analytical tools for describing the two-phase (brine and steam) flow in nozzles and blades have been developed. Experimental work has been utilized extensively to verify the calculational models.

The total flow impulse turbine dominates the effort of the energy-conversion engineering group. A recent test of a laboratory turbine has been a major step toward demonstrating the possibilities of this concept.

The total flow process consists of using a mixed-phase expander to expand the total brine-steam mixture from wellhead conditions to subatmospheric condensing conditions to drive an electrical generator. As a thermodynamic process, total flow has the potential for significantly more energy output per pound of fluid in comparison to other systems such as the flashed-steam or the binary system. The work of the energy-conversion engineering group has been directed toward making that process workable in a real machine, specifically the impulse turbine. Success in these efforts could lead to lower capital costs for the production of electrical power.

Several expanders were considered for the total flow process, but the impulse turbine is clearly the best choice for producing electrical power from the HT/HS hydrothermal resource. Other total flow machines, such as the Lysholm engine or the radial-

outflow reaction turbine, may be attractive as small units or as elements of a hybrid system (i.e., a small total flow expander in conjunction with conventional expanders). The hybrid applications are discussed in Section 3.3.

The total flow impulse turbine has progressed to the point where we can estimate fairly well the minimum efficiency of a full-scale turbine. Furthermore, as described in other sections of this report, there are now encouraging results on the control of scale. It is time to begin the conceptual design of the complete system and to develop the economic analyses of the impulse-turbine system as compared to other methods of utilizing the HT/HS resource.

Preliminary cost estimates have been made and are reported here. However, it is obvious that a great deal of additional work is necessary before definitive cost analyses can be completed. Laboratory work must be done to improve the performance and to determine the range of conditions within which the total flow impulse turbine can be effectively applied. Industrial experience must be applied to the design of the turbine and of the complete system. Scale-control methods must be refined and designed into the system.

An economic analysis of the total flow impulse-turbine system is only part of the story. Comparative analyses must be made for other methods, including scale control and the necessary equipment and materials.

Future activities related to the impulse turbine include the following:

1. Evaluation of methods for reducing liquid-droplet size, a key factor in maximizing performance.
2. Two-phase modeling for blade flow.
3. Cost analysis.
4. Conceptual design of a 2-MWe brine-tolerant field unit.

The feasibility of hybrid concepts depends strongly on the ability of conventional components (e.g., separators, scrubbers, and turbines using the steam) to deal with the brine.

In the case of the hybrid concepts, future work includes:

1. Evaluation of the Lysholm engine as an element of the hybrid.
2. Testing of the components of a radial-out-flow reaction turbine.

3. Study of applications.
4. Cost analysis for the use of nonconventional expanders.

A. W. Lundberg

3.2 Total Flow Impulse Turbine

As mentioned earlier, the LLL Geothermal Energy Development Program began in January 1974, with emphasis on development of the total flow process for the HT/HS resource. Existing turbine technology, for hydraulic or vapor flows, is not applicable to the total flow process. In the HT/HS resource, the wellhead fluid is a mixture of liquid and vapor, and the chemistry is a further complication. The development of successful systems for the total flow process will require considerable

effort in analysis, expander design, testing, and field experience.

Figure 3-1 is a temperature-entropy diagram for pure water. The fluid in a geothermal reservoir is actually a compressed liquid but is shown for simplicity as a saturated liquid at point 1. In a self-pumping mode of operation, the fluid emerges at the wellhead (point 2) as a two-phase fluid. Expansion through a two-phase machine occurs from

Fig. 3-1. Temperature-entropy diagram for the total flow process.

point 2 to point 3, and condensation of the vapor occurs from point 3 to point 4. The liquid is discarded in the sink condition at point 4.

Two points should be made about the total flow process:

1. The total flow process has the potential for

the highest energy efficiency because the available energy of the liquid phase is utilized.

2. The liquid phase, which constitutes about 80% of the mass flow rate, continues to evaporate through the process. In this respect the process differs from the conventional steam turbine, in which condensation occurs during expansion.

3.2.1 RATIONALE FOR THE IMPULSE TURBINE

Table 3-1 lists predicted well-flow characteristics for the self-pumping mode of operation as a function of reservoir temperature. The last entry in this table defines the design conditions we have chosen to use for a "typical" HT/HS resource, and all subsequent discussions refer to these conditions.

Initially, various machines were considered for the total flow process. The impulse turbine was selected as the most suitable candidate for several reasons, particularly its simplicity. All of the pressure and temperature drop occurs in the stationary nozzles, allowing cleaning or replacement if scale buildup were to occur. In addition, the components downstream of the nozzle, including the highly stressed turbine wheel, operate at a low temperature, say 50°C. Such a temperature is conducive to long-term materials reliability. Figure 3-2 schematically represents the axial-flow impulse turbine and illustrates the simplistic dependence of turbine efficiency on nozzle and wheel energy efficiencies.

Examination of the relationships shown in Fig. 3-2 leads to several observations:

1. Turbine efficiency is strongly dependent on nozzle performance because the velocity coefficient is squared.

2. Wheel efficiency is strongly dependent on momentum transfer from the liquid phase because the liquid is the major fraction of the mass flow.

3. The liquid phase must exist in droplets small enough to go with the vapor flow and not hit the blades, and hence turbine efficiency is strongly dependent on the size of droplets in the flow leaving the nozzle.

Analytical efforts for the impulse turbine are centered on the development of the following capabilities:

1. Modeling to predict turbine and nozzle performance with two-phase flow.
2. Two-phase fluid dynamics of fluid behavior in three-dimensional nozzles and curved blade passages.
3. A realistic droplet-breakup model.

Experimental activities for the impulse turbine include the following:

1. Design and demonstration of efficient supersonic nozzles for expanding a two-phase, single-component fluid.
2. Design and demonstration of the feasibility of the axial-flow impulse-turbine concept.

Table 3-1. Calculated geothermal well flow characteristics for self-pumping mode of production.

Reservoir temperature		Wellhead characteristics ^a				
°F	°C	Temperature (°F)	Pressure (psia)	Vapor fraction (%)	Flow rate (10 ³ lb/hr)	Thermal energy extraction rate ^b (MWt)
350	177	281	50	7.4	256.5	17.3
400	204	326	98	8.3	337.5	28.0
500	260	390	220	13.7	427.5	49.0
572	300	434	360	18.9	450.0	62.6

^a Well depth = 5000 ft; production casing = 7.625 in. o.d. × 6.770 in. i.d. (area = 0.25 ft²). Calculations based on the thermodynamic properties of pure water, Moody friction factor = 0.04.

^b With reference to saturated-liquid enthalpy at 120°F.

where

Fig. 3-2. The axial-flow impulse turbine.

- G. L. Dittman**

A single nozzle was used for the machine because of the limited flow-rate capabilities of the test facility. The nozzle was suspended with a four-bar linkage so that axial thrust could be measured independently during performance testing of the expander.

Fig. 3-3. Rotor assembled into rotor housing. (The front half of the housing has been removed.)

A dynamometer assembly (Fig. 3-4), consisting of a hydraulic pump and motor, was used both as a brake and as a motive source. The performance of the expander was measured by using the brake mode, whereas disk friction and windage losses were measured by using the hydraulic motor to drive the rotor.

W. J. Comfort

Fig. 3-4. Dynamometer assembly to which the expander was later attached for performance testing.

3.2.3 IMPULSE TURBINE TEST FACILITY

Performance tests of the LLL vertical impulse turbine were conducted at the LLL Geothermal Test Facility. The turbine test facility and the performance-test parameters are discussed here.

Vertical Impulse Turbine Test Facility

The vertical impulse turbine test facility basically consists of the four major systems discussed below.

Hydraulic Drive and Braking System. A closed-loop hydrostatic system provides drive to the turbine input shaft for measurements of disk friction and windage power losses. It also provides power braking to the turbine output shaft to load the turbine for measurements of steam-drive performance.

This hydraulic system is shown schematically in Fig. 3-5. In the drive mode, a diesel engine drives a remotely controlled variable-volume pump to provide control of system flow and thus turbine speed.

Fig. 3-5. Turbine drive and braking system.

Flow from the pump rotates a fixed-displacement hydraulic motor, which in turn drives the turbine through the dynamometer gear belt reducer.

In the brake mode, two-phase steam flow drives the turbine, which rotates the hydraulic motor through the dynamometer stand. Turbine output shaft braking is accomplished by the remotely controlled hydraulic backpressure regulator loading the hydraulic motor. Heat from the absorbed energy is removed from the hydraulic fluid in the water-cooled heat exchanger. The cooled flow bypasses the drive pump and returns to the motor.

Turbine shaft torque and speed are measured in the dynamometer, permitting calculation of disk friction, windage loss, and output power.

Steam Supply System. This system provides two-phase steam flow for the turbine operational performance testing. The turbine steam supply system is shown schematically in Fig. 3-6, and the thermodynamic process state points are shown in Fig. 3-7. Water from the hot well is raised to the desired test temperature by the gas-fired heater. The heated water is held above the saturated-liquid pressure by the bypass valve, which is a remotely set backpressure regulator.

Fig. 3-6. Steam supply system.

The turbine nozzle flow rate is measured in the saturated-liquid region. The liquid is then flashed (isenthalpic process assumed) to the desired nozzle inlet stagnation pressure through the remotely controlled throttling valve. The resultant two-phase flow expands through the nozzle and drives the turbine. The turbine exhaust is returned to the condenser along with the bypass valve flow and is condensed and pumped to the hot well at atmospheric pressure.

Turbine exhaust pressure is maintained at the desired subatmospheric level by controlling the quantity of atmospheric air inflow "leakage" to a mechanical vacuum pump (not shown in Fig. 3-6).

Fig. 3-7. Temperature-entropy diagram—facility and turbine test conditions.

Data Acquisition System. The vertical impulse turbine test facility provides for data access by means of a multichannel patching system available to all test locations. Data are also accessed by a multichannel Scannivalve, which inputs up to 20 pressure data points to a single transducer. The resultant data are then processed by an 80-channel data logger that provides paper-tape printout and output for magnetic tape recording.

Control System. For safety, all turbine tests are remotely controlled, with all personnel excluded from the test area. The turbine steam supply system uses pneumatic process controls; the turbine drive and brake system uses electrohydraulic controls.

Display is provided for all prime test parameters: turbine torque, speed, and calculated output power. Hydraulic system pressures and all critical data on turbine temperatures, pressures, vibration, and displacement are also displayed.

Overspeed and overtorque alarms and shutdown interlocks are provided along with audio and visual alarms on hydraulic overpressure, vibrations, and bearing overtemperatures.

G. W. Wright

3.2.4 EXPERIMENTAL RESULTS

The operating conditions used for testing the performance of the total flow impulse turbine are summarized in Table 3-2. These operating conditions are selected to be representative of the thermodynamic conditions of well outputs from the reservoirs of the Salton Sea Geothermal Field. Figure 3-8 shows the measured engine efficiency versus blade speed ratio (the ratio of the mean blade speed to the homogeneous-isentropic-mixture velocity of the fluid leaving the nozzle) for the machine. The maximum engine efficiency for the single-nozzle test was observed to be 23% at a blade speed ratio of 0.24. Testing was performed on three separate occasions and showed good repeatability. Operation was smooth and quiet.

The nozzle thrust coefficient was 0.83 during testing with the rotor. This was lower than the 0.94 thrust coefficient measured during previous tests of the nozzle alone. The nozzle thrust coefficient C_T is defined as

$$C_T = \frac{T}{\dot{m}_t V_{is}}, \quad (3-1)$$

where T is the measured thrust, $\dot{m}_t$ is the total mass flow rate, and V_{is} is the homogeneous isentropic mixture velocity.

Although radial pressure gradients associated with blade rotation are not as severe in two-phase conditions as would be expected in standard vapor turbines, they were probably large enough to explain the lower performance. Greater separation between the nozzle and the rotor as well as improved nozzle design should eliminate this problem.

W. J. Comfort

3.2.5 PREDICTION OF EXPANDER PERFORMANCE

A numerical model was developed and was used to predict expander performance. The model included calculation of droplet trajectories within the blade passage to determine what happened to the liquid. In addition to standard vapor-turbine losses, special losses associated with droplet impact on, and removal from, the blades were included in the model. Static cascade measurements in two-phase flow were used to determine the performance of blades identical with those on the rotor. This infor-

Table 3-2. Test conditions

Fluid state at nozzle entrance	
Pressure P_0	2.53 MPa (367 psia)
Quality x_0	14%
Temperature T_0	224°C (434°F)
Enthalpy h_0	1.2 MJ/kg (526 Btu/lbm)
Mass flow rate $\dot{m}$	0.59 kg/sec (1.31 lbm/sec)
Exhaust pressure and temperature	
Pressure P_e	0.0137 MPa (2 psia)
Temperature T_e	52°C (126°F)

Fig. 3-8. Measured engine efficiency versus blade speed ratio.

mation was used to normalize the vapor flow portion of the model. Measured values of combined disk friction and windage were used to normalize the disk friction and windage model in the predictive technique.

The model was designed to allow extrapolations of performance both for full admission and for changes in droplet diameter. The predictions of single-nozzle performance were very successful, as

will be shown, and lend strong credibility to the extrapolations.

The present numerical model is adequate only for impulse designs and cannot be used to select detailed blade contours because the vapor and liquids are not fully coupled; that is, liquid droplets are assumed to be affected by the vapor, but the vapor is assumed to be unaffected by the droplets. To design more advanced blade and nozzle contours, a completely coupled model for two dimensions, based on an existing one-dimensional two-phase-flow calculation technique, is necessary and is currently being developed.

The details of the numerical model are beyond the scope of this presentation. However, to provide the reader with some insight into the extrapolation from the single-nozzle to the full-admission results, a simplified model is presented here to demonstrate some of the characteristics to be expected.

Assuming for this simplified model that there is no slip between the vapor and the liquid entering the turbine blades, one can obtain the expression for blade efficiency e_b . For an impulse turbine with the mass-flow-rate ratio of vapor to mixture equal to R , relative velocity coefficients for the vapor and the liquid equal to λ_v and λ_l , blade speed ratio (blade speed/nozzle velocity) $U/V_{is} = \beta$, and nozzle angle θ , the blade efficiency is

$$e_b = 2\beta[R(1 + \lambda_v) + (1 - R)(1 + \lambda_l)](\cos \theta - \beta). \quad (3-2)$$

For a given blade speed ratio and nozzle angle, no higher conversion efficiency can be achieved than that indicated by Eq. (3-2) with $\lambda_v = \lambda_l = 1$. If all of the droplets impact the blade, then $\lambda_l = 0$, which reduces the maximum efficiency of the liquid kinetic energy conversion to 50%.

If some of the liquid escapes impact, the blade efficiency must be expanded to include those effects. To maintain a simplified approach, the analysis herein assumes that all of the liquid impacts the blade (i.e., $\lambda_l = 0$). Actual numerical results presented in the next section do not require this simplification.

Defining the optimum speed ratio, Eq. (3-2) can be differentiated with respect to the blade speed ratio and set equal to zero:

$$\frac{\partial e_b}{\partial \beta} = 0 = 2[R(1 + \lambda_v) + (1 - R)(1 + \lambda_l)](\cos \theta - 2\beta), \quad (3-3)$$

with the result that

$$\beta|_{\text{optimum}} = \frac{1}{2} \cos \theta.$$

It should be observed that the optimum blade speed ratio is independent of the vapor and liquid velocity coefficients λ_v and λ_l , and is only weakly dependent on θ for angles smaller than 20° .

To convert the blade efficiency to an engine efficiency e_e , the losses due to disk friction and to radial liquid removal, e_d and e_c , must be subtracted from the product of the blade efficiency and the square of the nozzle thrust coefficient:

$$e_e = C_T^2 e_b - e_c - e_d, \quad (3-4)$$

where

$$e_c \propto \alpha f(\beta^2), \quad (3-5)$$

$$e_d \propto g(\rho, \beta^{2.85}). \quad (3-6)$$

The quantity α in Eq. (3-5) represents the fraction of the liquid mass flow rate that must be removed radially, and ρ in Eq. (3-6) refers to the effective density of the fluid surrounding the rotor.

The previously derived optimum speed ratio is valid only when the disk-friction and windage loss and the pumping loss are small relative to the first term in Eq. (3-3). For a single-nozzle test, the disk-friction and windage loss and the liquid-removal loss can severely affect the blade speed ratio associated with the peak efficiency, shifting it toward a lower value. This in turn decreases the blade efficiency because the blade speed ratio is reduced. For full admission and a given blade speed ratio, the disk-friction and windage loss is inversely proportional to the mass flow rate, while the liquid-removal loss is proportional to the mass flow rate if all droplets impact the blade and are radially removed. Thus the liquid-removal loss is not diminished relative to power output for increased admission, while the disk-friction and windage loss fraction is reduced. As admission is increased, the optimum blade speed ratio increases, but since the liquid-removal loss is proportional to the blade speed ratio squared, the loss fraction increases.

With this brief introduction to some of the phenomena involved, the actual numerical model results are next compared to the experimental results and then the numerical model is used to extrapolate to full-admission performance and to an advanced design.

W. J. Comfort

3.2.6 EXTRAPOLATIONS TO FULL-ADMISSION PERFORMANCE AND TO AN IMPROVED DESIGN

Figure 3-9 presents further evidence that the numerical model compares very well with the experimental results. As noted, the upper calculated band assumes that disk-friction and windage losses are associated with the vapor density only, while the lower band assumes that they are a function of the two-phase-mixture density. The upper and lower limits of each of the bands are determined by nozzle modeling uncertainty.

The results of static cascade testing indicated that all droplets impacted the blade passages and exited at negligible velocity. The droplet diameter is estimated to be between 2.7 and $7\text{ }\mu\text{m}$. The results of performance predictions indicate that the droplet diameter is larger than $2.2\text{ }\mu\text{m}$ because this is the largest size of droplet that can pass through the blade passage without impact. Hence, if droplets are more than $2.2\text{ }\mu\text{m}$ in diameter, all droplets will impact on the blade passage—as indicated by the results.

The blade speed ratio indicated for the peak power point of the experimental data lies between the two calculated bands. This is significant because, as was shown, the optimum blade speed ratio for an impulse turbine depends primarily on the disk friction and windage, and the losses associated with the radial removal of liquid droplets that have impacted the blades. The fact that the optimum blade speed ratio for the bounding calculations spans the measured optimum speed ratio indicates that the mechanisms of disk friction, windage, and liquid removal are well modeled. If all droplets splash off the rotor-housing walls and remix with the vapor, the effect will be to increase the effective density of the fluid mixture around the rotor and consequently to increase the friction forces and the power necessary to accelerate relatively low velocity water particles.

Figure 3-10 shows extrapolations to a full-admission performance for the existing rotor design and to an advanced design. It should be noted that the full-admission results reflect the nozzle thrust coefficients previously measured for the nozzle in the laboratory. Otherwise, the calculation contains the same parameters for the full-admission calculation as for the partial-admission calculation, except that the admission was increased. The increase in performance is due primarily to the reduced effects of disk friction and windage since this loss becomes very small in comparison to full-admission power input, whereas it is rather large compared to that of

Fig. 3-9. Comparison of experimental data with turbine performance model predictions.

partial admission. This reduction allows the rotor to attain a higher speed ratio, which increases the engine efficiency.

Two bands are used to represent the extrapolated performance of a full-admission design for droplet diameters greater than $2.2\text{ }\mu\text{m}$ and with an assumed nozzle thrust coefficient of 0.94. The difference between the upper and lower bands (broken and solid lines, respectively) is the result of liquid removal from the blades and is included in the lower band (solid lines). Though this loss is certain in the single-nozzle design, it is not clear that it will exist in the full-admission machine because the nearly continuous flow may force the liquid between the blades without significant radius change. The upper band (broken lines) indicates the displacement of the lower band (solid lines) because of the absence of the losses associated with radial liquid removal from the blades. The upper bound of both bands is calculated by assuming that the disk-friction and windage loss is controlled by the vapor density and that the slip ratio (the ratio of average liquid velocity to average vapor velocity at the exit of the nozzle) is approximately 0.9. The lower bound of both bands is calculated assuming that the disk-fric-

Fig. 3-10. Total flow impulse-turbine test results and performance evaluation.

tion and windage loss is controlled by the mixture density and that the slip ratio is approximately 0.7. For full-admission performance, the slip ratio, rather than the fluid density assumed for the disk friction and windage, is the major cause of the difference between the upper and lower bounds of each band.

The advanced design assumes that the droplet size has been reduced to $1 \mu\text{m}$ and that the thrust coefficient remains 0.94. It is expected that under these circumstances the liquid and vapor will leave the nozzle with very nearly the same velocity. The upper bound of the lower band (solid lines) is based on vapor-turbine correlations of vapor friction losses and the assumption of vapor-controlled disk friction and windage. The lower bound of the lower band is based on blade vapor performance measured in static cascade tests and assumes that the mixture density controls disk friction and windage. The upper band for this case (broken lines) indicates the performance if radial liquid removal losses are omitted. The change resulting from the omission is not as great as in the previous case (full

admission with droplet diameters greater than $2.2 \mu\text{m}$) because only a small fraction of the liquid impacts on the blades when the droplet diameter is $1 \mu\text{m}$.

The single-nozzle, full-admission extrapolation, and advanced design results may be compared in another way. Table 3-3 represents a summary of losses associated with the peak-efficiency points corresponding to the data and extrapolations shown in Fig. 3-10. It should be noted that this table does not indicate causality, but rather a loss summary at a particular operating condition. For example, from the single-nozzle results, one might conclude that disk friction is not a deterministic loss mechanism. However, disk friction is not an independent function, just as the other losses listed are not independent functions. In the case of disk friction, its nearly cubic relationship with the blade speed ratio and its large relative magnitude compared to the power-output capability of a single-nozzle test forces the blade speed ratio to depart considerably from the optimum. This, in turn, results in the significant loss ("geometry and nonoptimum blade speed

Table 3-3. Loss distribution at peak efficiencies for single-nozzle design and for extrapolations to full-admission existing and advanced designs

Factor	Single nozzle, $D > 2.2 \mu\text{m}$ (%)	Full-admission bounds (%)			
		Existing design, $D > 2.2 \mu\text{m}$		Advanced design, $D \leq 1 \mu\text{m}$	
Slip, liquid/blade; vapor friction	17	33	34	14	10
Liquid pumping	2	6	0	2	0
Disk friction and windage	4	<1	<1	<1	<1
Geometry and nonoptimum blade speed ratio	33	13	7	6	6
Nozzle inefficiency	21	10	11	11	11
Total losses	77	62	52	33	27
Engine efficiency	23	38	48	67	73

ratio") that results directly from blade efficiency relationships as previously shown.

As described above, considerable improvement can be expected in turbine performance as a result of droplet-size reduction. The performance indicated for droplets smaller than $1 \mu\text{m}$ also requires that adequate two-dimensional analytical methods be developed to improve two-phase blade and nozzle design.

It should be noted that the extrapolations in Fig. 3-10 are based on the configuration of the existing wheel. Figure 3-11 shows the effect of simply increasing the wheel width B up to $3B_0$. It is clear that even if droplet size cannot be reduced below 2 to $3 \mu\text{m}$, an additional 10% increase in efficiency can be obtained by this simple change. Indeed, it appears possible to achieve the research goal of 70%

engine efficiency for the machine. Using the test conditions of Table 3-2 as representative, a 70% engine efficiency corresponds to a resource utilization rate (water rate) for pure water of 47 lb/kWh gross—that is, exclusive of the parasitic loads that would occur in a typical power plant application. This represents a significant improvement over conventional conversion systems operating under the same conditions. This comparison is shown in Table 3-4. The important implication is that the number of wells required for a given power output is correspondingly reduced, which in turn reduces the initial capital investment since the cost of wells is dominant.

In summary, a two-phase axial-flow impulse expander has been successfully tested in the laboratory. An engine efficiency of more than 23%

Table 3-4. Estimated performance comparison (gross electrical output) of the total flow impulse turbine and flashed-steam systems^a

System	Water rate (lb/kWh)	Specific output (W-hr/lb)
Total flow impulse turbine:^b		
Existing design-full admission (38–48% engine efficiency)	86–68	12–25
Advanced design-full admission (70% engine efficiency)	47	21
Flashed-steam systems:		
Single flash (75% engine efficiency)	70	14
Double flash (75% engine efficiency, both stages)	56	18

^a Calculations based on the thermodynamic properties of pure water. For presence of dissolved solids, reduce energy output by 0.85% for each 1% TDS.

^b Calculations based on the test conditions given in Table 3-2.

Fig. 3-11. Idealized rotor performance as a function of droplet diameter for various blade widths.

for a single-nozzle test was measured. The turbine performance predictions of a numerical model agree well with experimental results. Extrapolations to full-admission performance using the numerical performance model and based on achievable nozzle thrust coefficients indicate that a full-admission engine efficiency of 38 to 48% can be realized with presently available technology. Droplet-size reduction to $1 \mu\text{m}$ and improved techniques for the analysis of two-phase flow in the design of blades and nozzles should make it possible to achieve the research goal of 70% engine efficiency.

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3.2.7 NOZZLE DESIGN AND ANALYSIS

There are two main goals for the two-phase-nozzle program. One of these goals is the efficient conversion of the inlet thermal energy in the fluid to kinetic energy at the nozzle exit for use in the impulse turbine. The second main goal is to produce small droplets ($1 \mu\text{m}$) at the nozzle exit. Because the fluid is a two-phase mixture of droplets dispersed throughout a vapor continuum, the droplets must be small for the efficient transfer of momentum to the turbine wheel.

The methods used to achieve these goals include both theoretical and experimental bases. The theoretical modeling is used for initial experimental design and, after experimental verification (or modification), future advanced design. This section discusses in some detail the goals and the results to date of the two-phase-nozzle program.

Theoretical Activities

The emphasis of the theoretical program for two-phase-nozzle development is the accurate prediction of the nozzle flow characteristics. This goal of accurately predicting flow character has been accomplished through the use of the following computer programs:

1. Isentropic homogeneous equilibrium model with computerized equation of state for pure water and for simulated brine.

2. Quasi-one-dimensional, two-phase, single-component model.

3. Quasi-one-dimensional, two-phase, single-component, Eulerian mixture, Lagrangian droplet model including normal shock waves.

Work is proceeding at present to develop a two-dimensional prediction capability for two-phase-flow analysis, an extension of item 3 above.

Experimental Nozzle Performance Activities

The goals of the experimental nozzle performance program have been to determine the efficiency of the high-velocity two-phase nozzles and to verify the analytical tools. The performance of both axisymmetric conical nozzles and rectangular three-dimensional nozzles has been determined and is discussed in this subsection.

Before describing the nozzle performance experiments, it is useful to define several parameters related to nozzle performance. The nozzle thrust coefficient is, as defined in Eq. (3-1),

$$C_T = \frac{T}{\dot{m}_t V_{is}}$$

where T is the measured thrust, $\dot{m}_t$ is the total mass flow rate, and V_{is} is the homogeneous isentropic mixture velocity. When the pressure terms in the thrust equation cancel, the thrust

coefficient becomes a velocity coefficient given by

$$C_T = \frac{\bar{V}}{V_{is}},$$

where $\bar{V}$ is the average exit velocity for the nozzle. The nozzle efficiency is defined as

$$\eta^2 = \frac{RV_v^2 + (1-R)V_d^2}{V_{is}^2},$$

where V_v is the vapor exit velocity, V_d is the droplet exit velocity, and R is the mass flow rate

ratio $\dot{m}_v/\dot{m}_t$. The velocity coefficient and the thrust coefficient are then related by

$$\eta^2 = \left\{ \frac{R + (1-R)S^2}{[R + (1-R)S]^2} \right\} C_T^2,$$

where S is the slip velocity V_d/V_v (note that for $S \geq 0.9$, $\eta^2 \approx C_T^2$).

The nozzle performance test arrangement is shown pictorially in Fig. 3-12 and schematically in Fig. 3-13. The hot water enters the nozzle test chamber, where it flashes to a two-phase mixture before reaching the nozzle entrance. The experimental information includes the hot-water conditions, the nozzle pressure profile, the nozzle thrust, and the nozzle exit pressure.

Fig. 3-12. Setup for nozzle performance test.

Fig. 3-13. General nozzle test station schematic and operation cycle.

Experimental pressure profiles for a nozzle operating at constant inlet conditions and three different exit pressures are shown in Fig. 3-14. The upper broken curve (circles) indicates a shock wave present in the nozzle (overexpanded; i.e., the pressure ahead of the shock is lower than the ambient pressure), which is an operating condition of very low efficiency because of the reduced exit velocity. A photograph of the nozzle jet operating with a shock wave inside the nozzle is shown in Fig. 3-15a. The jet is clearly seen to be turbulent and unstable, indicating reduced efficiency.

Fig. 3-14. Nozzle performance map.

The lower broken curve (diamonds) of Fig. 3-14 indicates an expansion process occurring at the nozzle exit (underexpanded; i.e., the nozzle exit pressure is higher than the ambient pressure). This condition is shown by the nozzle exit jet in Fig. 3-15b. The expansion in the jet is clearly indicated. Again, this represents inefficient nozzle operation because the fluid leaves the nozzle at a reduced velocity.

The central curve (triangles) of Fig. 3-14 indicates a near-optimum expansion in which the nozzle exit pressure is very near the ambient pres-

(a)

(b)

(c)

Fig. 3-15. Visual observations of the nozzle exit jet-flow pattern: (a) overexpanded, (b) underexpanded, (c) near optimum.

sure. The exit jet corresponding to this condition is shown in Fig. 3-15c. This represents efficient operation since the exit velocity is a maximum for the ambient exit pressure conditions.

A comparison between an experimental pressure profile and a theoretical pressure profile is shown in

Fig. 3-16. The numerical results (solid line) compare with the experimental results well within the experimental error limits. However, the isentropic homogeneous equilibrium (IHE) model (lower curve) predicts a pressure profile with pressures much lower than the experimental. This is due to the ideal nature of the IHE model. From this comparison it is concluded that theory and experiment are in excellent agreement.

A series of conical nozzles were tested at LLL to determine the optimum operating conditions. To determine the optimum, the inlet conditions (pressure and quality in the chamber, P_c and x_c) were fixed and the ambient exit pressure varied. Then,

Fig. 3-16. Comparison of theoretical and experimental nozzle performance results.

3.2.8 DROPLET-PHASE CHARACTERIZATION

The goals of the droplet-phase characterization program are to determine the droplet-phase characteristics throughout typical two-phase nozzles and to produce droplets $1 \mu\text{m}$ in diameter. The achievement of these goals requires several different ex-

Fig. 3-17. Two-phase-nozzle performance under constant inlet conditions (pressure and quality in the chamber, P_c and x_c) and varied ambient exit pressure.

by plotting the thrust coefficient versus the ambient exit pressure, the performance data shown in Fig. 3-17 were obtained. The data indicate velocity coefficients near 93% in the cases tested (86% efficiency). Thus it was determined that efficient nozzle operation on low-quality steam can be obtained with simple conical nozzles. Tests of rectangular nozzles showed no significant changes in efficiency.

T. W. Alger

perimental tools, including a transparent-nozzle arrangement, a nozzle flow visualization technique, a droplet-velocity measurement technique, and a droplet-size measurement technique. The chosen experimental tools are described in this section.

Transparent-Nozzle Test Arrangement

The transparent-nozzle test arrangement is shown in Fig. 3-18, and schematics of the test setup are presented in Figs. 3-19, 3-20, and 3-21. The pulsed ruby laser emits approximately 2 J in a pulse time of 20 nsec. This allows a "stop-action" picture of the flow. Variation in light scattering across the nozzle flow provides information concerning the liquid-phase spatial distribution.

Fig. 3-18. Transparent-nozzle test arrangement.

Droplet-Velocity Measurement

The experimental technique that will be used to measure droplet velocity is a laser-Doppler velocimeter. A schematic of the experimental arrangement is shown in Fig. 3-20. A laser beam is split and focused to an intersection point in the flow where the velocity is to be measured. In this region the two focused light beams interfere, creating a fringe pattern. As a droplet traverses this region, it scatters light from the bright fringes and gives a light signal pulsed at the fringe-crossing frequency, which is proportional to the droplet velocity. This signal is received by a photosensor and analyzed by a spectrum analyzer (or similar device) to determine the Doppler frequency. Preliminary measurements of nozzle flow have been performed with the laser-Doppler vel-

Fig. 3-19. Schematic diagram of laser shadowgraph.

Fig. 3-20. Schematic diagram of laser-Doppler velocimeter.

ocimeter, and at present the equipment is being installed.

Droplet-Size Measurement

The technique for droplet-size measurement is based on the theoretical scattering of light from a single spherical particle. This theory is readily extended to the scattering of light from many particles of different sizes, provided that the light incident on all particles is the same (single scattering). By the measurement of the angular distribution of the scattered light, the particle size spectrum can be determined.

A schematic of one possible experimental arrangement is shown in Fig. 3-21. The technique is based on the use of a calibrated film to determine the angular distribution of scattered light. Each

piece of film is calibrated individually to increase accuracy. By measuring the quantity $I(\theta)/I_0$ from the equation

$$\frac{I(\theta)}{I_0} = C \int_0^\infty i(\alpha, \theta, m) f(\alpha) d\alpha \quad (3-7)$$

and calculating the theoretical Mie scattering function $i(\alpha, \theta, m)$, the particle-size distribution function $f(\alpha)$ becomes the only remaining unknown (C is an optical system constant). Thus, by an inversion of the integral, the distribution function $f(\alpha)$ can be determined.

Fig. 3-21. Schematic diagram of laser apparatus for droplet measurement.

Experiments were performed using glass beads in water ($15\text{-}\mu\text{m}$ average diameter from photomicrographs) to determine the applicability of this experimental technique. A film-density contour graph of a typical piece of film is shown in Fig. 3-22. An isometric plot of the same film plane is shown in Fig. 3-23. The exposures across the top of the film supply the film calibration data. The exposure on the lower right side of the film is the initial laser beam without scattering particles; the exposure on the lower left side of the film is the light after scattering by glass beads. This clearly indicates the angular scattering caused by the particles.

For final data reduction, the film is scanned by a microdensitometer to obtain accurate readings of the film density. Then, by using the known energy in the calibration exposures, a relationship between film density and energy density can be determined.

Fig. 3-22. Laser measurements of droplets. Film-density contour graph of a typical piece of film.

Fig. 3-23. Isometric plot of the film plane shown in Fig. 3-22.

By using this relationship, the film density corresponding to the initial and scattered light beams can be converted to energy density or light intensity.

Figure 3-24 shows the energy density in the scattered beam after the calibration has been applied by computer. This figure provides the data required for determining the droplet-size distribution by means of Eq. (3-7). Measurements with glass beads by this technique and by photomicrography agree within 10% for the mean diameter and the mean volume-to-surface-area diameter. At present, effort is being applied to use this technique for the measurement of liquid-droplet size in the nozzle flows.

T. W. Alger

Fig. 3-24. Light scattering by model system of glass spheres in water (vertical scale in joules per square centimeter).

3.2.9 STRATEGY FOR DROPLET-SIZE REDUCTION

The conventional approach to predicting droplet size in a dispersed gas-liquid flow is to use the Weber-number criterion. The Weber number, by definition, is the ratio of aerodynamic forces to surface-tension forces on a liquid droplet. If the aerodynamic forces (e.g., the pressure difference between the windward and leeward side of the droplet) become sufficiently large compared to the surface-tension forces holding the droplet together, the droplet will break up into smaller segments. Experiments show that breakup occurs at Weber numbers between 6 and 10.

With the steam-water flow through a converging-diverging nozzle, the liquid droplets are unable to attain the high acceleration of the vapor in the throat region of the nozzle. Consequently a velocity difference develops between the droplet and vapor, and gives rise to an aerodynamic force sufficient to cause droplet breakup. Calculations based on the Weber number predict droplet sizes of approximately $5 \mu\text{m}$ in the nozzles currently under study for geothermal power conversion applications.

The fact that the steam-water flow from a geothermal resource is essentially a single-component flow suggests the feasibility of a different mechanism for droplet breakup. In addition to the

velocity difference that develops between the droplet and the vapor, a corresponding thermal lag appears because of the finite heat-transfer rate within the droplet; that is, the internal temperature of the droplet will be higher than that of the surrounding vapor temperature. Internal boiling will occur and lead to droplet breakup unless the internal pressure augmentation due to surface tension is adequate to prevent boiling. Thus the critical droplet size is that for which the internal pressure due to surface tension is just adequate to prevent boiling due to thermal lag within the droplet. This mechanism comprises the boiling-breakup hypothesis. Preliminary calculations based on the boiling-breakup criterion predict a droplet size smaller than $3 \mu\text{m}$ in nozzles currently under study.

More accurate calculations and experiments are needed to evaluate the validity of the boiling-breakup hypothesis. These are included in the program for FY 1977.

Concomitant with further investigation into the droplet-breakup model and its relevance to geothermal power conversion applications is a small effort in assessing the feasibility of ultrasonic or electrostatic applications in droplet breakup.

C. T. Crowe

3.2.10 PRELIMINARY COST ESTIMATE

A preliminary estimate of the cost of a 2-MWe "power plant" and a 2-MWe field test facility is summarized in Table 3-5 for two noncondensable-gas contents expressed as a percentage of the total brine weight flow. It should be borne in mind that these estimates represent approximately 2 weeks of

effort on the part of a turbine manufacturing company and about a month's effort for a consulting architect-engineer. The turbine estimate assumed a 70% efficient version of the design tested in the laboratory, using materials we believe will be adequate for acidified-brine service. This design would

Table 3-5. Order-of-magnitude cost estimate for 2-MWe total flow system

Item	Noncondensable gas content	
	0.5 wt%	1.5 wt%
Impulse turbine, controls, load	\$ 600,000	\$ 600,000
Balance of plant	760,000	839,000
Cost of 2-MWe experimental field facility	\$1,360,000	\$1,439,000
Additional equipment	214,000	214,000
Total cost of hypothetical 2-MWe power plant	\$1,574,000	\$1,653,000

Table 3-6. Order-of-magnitude cost estimate for a 2-MWe impulse turbine facility

Item	Noncondensable gas content	
	0.5 wt%	1.5 wt%
Turbomachinery:	\$ 600,000	\$ 600,000
2-MWe turbine with operating and emergency controls		
2.5-MVA generator with excitation package		
Reduction gear		
Lubricating oil system		
Total turbomachinery	\$ 600,000	\$ 600,000
Balance of plant:		
Brine supply and reinjection	85,000	85,000
Acid treatment system	168,000	168,000
Exhaust brine separator and hotwell	158,000	158,000
Exhaust steam condenser and vacuum system	279,000	358,000
Process water supply	36,000	36,000
Auxiliary items	208,000	208,000
Electrical substation	40,000	40,000
Total balance of plant	\$ 974,000	\$1,053,000
Grand total for power plant	\$1,574,000	\$1,653,000
Cost reduction for 2-MWe field facility:		
Water brake	\$ 81,000	
LLL trailers	58,000	
Gear set	35,000	
Substation	40,000	
Total	\$214,000	
Total field facility	— \$ 214,000	— \$ 214,000
	\$1,360,000	\$1,439,000

have a shaft speed of about 7000 rpm, requiring the use of a reduction gear that will not be necessary in a commercial version because a 3600-rpm design can be used.

The specific equipment categories used in the cost estimate are given in Table 3-6. The lower cost for a field facility comes about because the genera-

tor is replaced by a less expensive water brake dynamometer, the electrical substation and speed reduction gear set are not needed, and permanent office and shop facilities can be replaced with temporary laboratory trailers.

G. L. Dittman

3.2.11 FUTURE ACTIVITIES FOR THE TOTAL FLOW IMPULSE-TURBINE SYSTEM

In 1976 a laboratory version of a total flow impulse turbine was tested. This single-nozzle experiment verified the analytical performance model used to extrapolate to the full-admission case and showed that the goal of 70% efficiency is achievable if the present work on droplet-size reduction in the two-phase nozzles is successful. The performance of the laboratory turbine, extrapolated to full-admission performance from the single-nozzle tests, showed that about 40% efficiency is a lower limit for the current design.

Nozzle performance has been shown to be high, but blade performance is dependent on droplet size. From past experiments, a droplet size of 3 to 7 μm can be inferred. The actual measurement of droplet size to verify reduction within the range of 0.5 to 1.5 μm is a major part of the FY 1977 work on total flow. Other activities include continued development of analytical methods for two-phase flow over the blades and other tests relating to the performance of a complete system, some in the field environment. All of this work should lead to data that verify the research goal of an engine efficiency of 70% or a reduction of the water rate to as low as 47 lb/kWh. The implications of this are shown in Table 3-4, which compares the performance of total flow and flashed-steam systems.

Now that some fundamental achievements have been made with the turbine test in the laboratory and scale control in field experiments, it is possible to carry out meaningful economic analyses of the total flow impulse-turbine system applied to the HT/HS resources.

Substantial industry participation is planned in developing designs and cost estimates for the turbine and for the complete system. The overall total flow impulse-turbine plan for FY 1977 is shown in the milestone chart (Fig. 3-25) and is explained below. The intent is to involve strong industry participation for the design and construction of a 2-MWe brine-tolerant system. Preliminary contacts with a turbine manufacturer and an architect-engineer firm indicate that they require a

lead time of about 18 months from design freeze to completion and test installation.

Droplet-Breakup Nozzle Development

The object of this task is to quantitatively characterize the liquid portion of the two-phase fluid, to understand the phenomenology of droplet breakup, and to effect droplet control within the flow of a supersonic nozzle expanding a steam-water mixture. This task is being pursued to realize a significant potential increase in turbine performance, corresponding to a reduction in droplet size at the nozzle exit to about 1 μm or less.

The mechanism controlling droplet breakup will be studied by theoretical and experimental evaluation of a new concept—boiling breakup. Thermal nonequilibrium is assumed to exist at the nozzle throat. The resultant temperature lag in the liquid phase will result in droplet boiling and breakup if the internal pressure due to surface tension is not high enough to prevent it. A mathematical model will be formulated by incorporating thermal nonequilibrium into an existing one-dimensional two-phase-flow computer program (1D2FAZ). Insight will be gained by comparing test results with predictions from this model and the traditional Weber-number criterion for droplet sizes.

During FY 1977, a series of experiments will be performed to characterize the water portion of the steam-water mixture flowing through transparent nozzles. Laser optical techniques, whose development started in FY 1976, will be used to measure droplet size, velocity, and distribution within the flow field (void fraction) for several nozzle-throat geometries as a function of various inlet and exhaust conditions. Various radii of curvature in the throat area and throat diameters will be investigated as the baseline method of droplet reduction since this is where the maximum pressure and temperature gradients exist.

Other strategies or techniques for droplet control will also be reviewed during the year. High-relative-

Fig. 3-25. Fiscal year 1977 schedule for total flow impulse turbine. The shaded bars denote test periods.

velocity remixing within the nozzle of previously separated liquid and vapor phases appears promising as a method of increasing droplet breakup. The potential of coupling electrostatic or ultrasonic energy into the droplets to increase breakup will also be assessed.

This task is divided into experimental and analytical portions, described below.

Light-Scattering Verification Tests. This subtask includes the tests necessary to verify the light-scattering technique that will be used for measuring droplet size and void fraction in two-phase nozzles. Droplet velocity will be measured by means of a laser-Doppler velocimeter.

A planar (constant-thickness flow path) transparent nozzle has been fabricated and demonstrated as a useful experimental tool. This nozzle has been used to verify the flow-visualization technique (shadowgraph), allowing a much greater understanding of the flow processes. It has also been applied to demonstrate the use of a laser-Doppler velocimeter for the measurement of droplet velocity in the high-velocity, high-droplet-concentration flow.

Because of severe light attenuation (due to multiple scattering) that occurs in the existing nozzle, the droplet-size measurement technique has not yet been demonstrated. Light-scattering theory is valid only for single scattering. For this reason, a metal nozzle has been fabricated with ports for light probes to allow adjustment of the optical depth. This arrangement will allow the determination of the range of nozzle flow conditions and optical thicknesses over which valid droplet-size measurements can be made.

Droplet-Breakup Tests. Droplet-breakup tests with light-scattering techniques include measurement of droplet characteristics (droplet size, void fraction, and velocity) as a function of the nozzle-throat geometry for various inlet and exhaust conditions.

Preliminary theoretical results indicate that the droplet size at the nozzle exit can be minimized by maximizing pressure or thermal gradients in the nozzle throat. These gradients are controlled by the throat geometry (radius of curvature and throat diameter). The experimental program for FY 1977 will be to investigate several throat geometries to determine the limits of droplet-size reduction through changes in nozzle geometry.

Development of the Boiling-Breakup Model. A mathematical model will be developed of the temperature nonequilibrium (i.e., boiling) droplet

breakup in a steam-water mixture flowing through a supersonic nozzle. To date, droplet breakup has been predicted by using the Weber-number criterion (i.e., aerodynamic forces overcoming the surface-tension forces that hold the droplet together and resultant breakup). There is reason to believe that the Weber-number criterion is inadequate for single-component flows, where breakup may occur due to internal boiling; that is, a temperature lag due to thermal nonequilibrium could cause breakup unless the internal pressure due to surface tension is high enough to prevent boiling.

The nonequilibrium model depends on a detailed calculation of the temperatures of the liquid and of the vapor in the throat region of the nozzle. The present one-dimensional calculational model (1D2FAZ) assumes temperature equilibrium between phases. Changes to this model will include the introduction of the equation-of-state functions to encompass the possibilities of superheated and compressed liquid and the introduction of an appropriate interphase heat-transfer coupling equation. It is anticipated that this will improve the prediction of droplet-size reduction in single-component flows and increase understanding of the nonequilibrium phenomena occurring in the nozzle.

This understanding will also provide some guidance for estimating nozzle efficiency when expanding lower enthalpy geothermal fluids.

The insight gained in the one-dimensional modification will establish the need for including nonequilibrium thermal effects in the development of the two-dimensional computer program.

Evaluations of the Boiling-Breakup Model. The boiling-breakup model represents a new concept in droplet-size control in single-component two-phase flows and requires evaluation of its applicability to low-quality steam-water nozzle flows for total flow energy-conversion schemes. During FY 1977 a series of calculations will be carried out using the computer program developed in light-scattering verification tests to determine the effect of nozzle design parameters and fluid properties on droplet size. The nozzle performance predicted will be compared with experimental results and with predictions made on the basis of the conventional Weber-number criterion.

Analysis of Phase Remixing in the Nozzle. Preliminary estimates indicate that a high-relative-velocity remixing of previously separated liquid and vapor phases will enhance droplet breakup (according to a critical Weber-number criterion).

However, these estimates do not include possible degrading effects to the nozzle flow—for example, a change in nozzle efficiency or a change in the nozzle mass flow rate. During FY 1977 the effect of phase remixing on the overall nozzle flow field will be analytically investigated to evaluate the concept as a possible candidate for droplet breakup.

Analysis of Electrostatic and Ultrasonic Techniques. Other methods that have been used for droplet-size control are electrostatic and ultrasonic techniques. Preliminary assessment of these methods is needed to determine their suitability for droplet-size control in the total flow energy-conversion scheme. During FY 1977 a literature search will be made to review the techniques and efficiency of ultrasonic and electrostatic methods. The result will be a preliminary assessment of the suitability of these methods in total flow applications.

Two-Phase-Flow Blading Design

The objective of this task is to develop the analytical models and solution techniques necessary to design the blades (and nozzles) for an advanced, highly efficient turbine expanding a geothermal steam-water mixture (total flow).

The effort invested in this task will result in the capability to give guidance on two-phase-flow design to potential industrial manufacturers of a total flow impulse turbine or any other axial-flow turbine operating on two-phase flow. The work will be primarily analytical in FY 1977 and will concentrate on the development of a two-dimensional two-phase-flow calculation technique that requires the concurrent development of a two-phase boundary-layer model.

The calculation technique for two-dimensional flow has a high probability of being successfully developed because of our previous analytical work. Our experience with a one-dimensional two-phase-flow calculation technique (1D2FAZ) developed in FY 1976 indicates that the numerical solution scheme can be extended to the two-dimensional case to adequately model the flow field. The major concerns are computation time, numerical stability, and boundary conditions. Stability problems can be reduced with increased computation time. We expect that the boundary conditions, though different from other fluid-dynamics problems involving only a continuum, will provide no major obstacles. The boundary-layer model has no major uncertainties

and should be ready for testing and application with the two-dimensional calculations.

The task is divided into an analytical and an experimental subtask. The code development will be accomplished in the analytical subtask, and the experimental subtask will be needed to verify its predictions by laboratory testing.

Two-Dimensional-Flow Code (2D2FAZ). Existing analytical fluid-dynamics methods for turbine design are not applicable to the design of an axial-flow impulse turbine expanding a steam-water mixture. The effects of energy and momentum coupling between the vapor phase and the liquid phase are significant and not accounted for in standard turbine design codes. In order to design a highly efficient flow path for a total flow turbine, additional analytical tools that incorporate these effects must be developed. Experimental measurements are both difficult and expensive and cannot provide predictive design capability unless a very large, costly, and time-consuming test matrix is utilized. A two-dimensional two-phase-flow calculation technique is being pursued that will also include the effects of shock phenomena, since the turbine design has both subsonic and supersonic flow conditions.

The development of the two-dimensional two-phase-flow calculation technique (2D2FAZ) will be based on a proved one-dimensional technique (1D2FAZ). The solution will be initially designed for calculations assuming thermal equilibrium between phases. Thermal nonequilibrium will be incorporated later if nozzle experiments and the extension of the one-dimensional technique to the nonequilibrium case indicate sufficient need.

The formulation requires the solution of eight equations at each point in the flow field. Four of the eight are partial differential equations requiring a special numerical technique that has not been applied to turbine flow passages even for single-phase flows. In order to properly handle arbitrary blade profiles, the technique is being formulated in non-orthogonal coordinates. The experience of other researchers, though limited, indicates that this can lead to mesh-related instabilities, which can, however, be overcome at the expense of computation time. Modeling of droplet-wall interactions will produce boundary-condition problems that have not been previously addressed.

Two-Phase Boundary-Layer Model. Blade design for two-phase flow will require a viable physical model for the two-phase boundary layer in addition to the 2D2FAZ model. The presence of the

droplets in the boundary layer alters the momentum- and energy-transfer processes affecting blade performance.

The two-phase boundary-layer model to be developed in FY 1977 will be an extension of classical and extremely practical boundary-layer integral techniques modified to include the presence of the liquid phase.

Wedge-Geometry Blade Tests. The wedge geometry will be used to compare experimental and predicted subsonic and supersonic results in the region of the blade leading edge. The wedge will be fitted with transparent flow-guidance walls to allow optical measurements (see discussion of light-scattering verification tests on page 41) and with static pressure measuring taps on the wedge surface. In addition, pitot probes may be used if appropriate.

Cascade-Configuration Blade Tests. The cascade configuration, consisting of several blades, is necessary for the experimental verification of a more complex flow field than the simple wedge. The cascade will also be fitted with transparent walls to allow optical investigation and will include static pressure taps on the blade surfaces.

Impulse-Turbine System Tests

In the past, all tests conducted as part of the impulse-turbine effort have been performed in the laboratory with clean water. Except for the single-nozzle system test that was made in late FY 1976, test work has dealt with turbine components (i.e., nozzles and assemblies) that simulated rotor blades. The object of this task is to begin integrating the key elements of the impulse-turbine system for continued laboratory testing and the commencement of testing in the field.

The major effort this year will be a field experiment to test several elements of the impulse-turbine system. One element will be a demonstration of the satisfactory performance of a candidate two-phase nozzle configured for optimum expansion of the chemically treated geothermal brine to a representative turbine exhaust pressure (i.e., approximately 0.2 atm). The nozzle inlet design conditions will be established by the pressure, temperature, and quality of the wellhead brine from the Magmamax No. 1 well at the LLL Geothermal Test Station at Niland, California. The other system aspects that will be demonstrated are scale control and solids characterization and control in turbine com-

ponents and in the condensing and cooling system. Candidate turbine materials will be evaluated at conditions simulating turbine operation (see Section 4).

An additional test on a single-nozzle system in the clean-water facility will be conducted next year on the existing wheel. The test will demonstrate the increase in turbine efficiency that results from the successful development of an improved nozzle design (reduced droplet size). The final test in this series will occur in FY 1978 and will incorporate both the improved nozzle and a new wheel with a two-phase blading design resulting from the 2D2FAZ code development work being conducted this year.

Field (Brine) Nozzle Performance Tests. The general performance of a two-phase nozzle expanding a representative chemically treated HT/HS geothermal brine to subatmospheric exhaust conditions will be demonstrated. The experiment will be conducted at the LLL Geothermal Test Station with fluid at wellhead conditions from the Magmamax No. 1 well.

An existing test trailer is being modified to accept a test chamber very similar in design to the chamber used for the laboratory nozzle tests. The wellhead product will be separated into its liquid and vapor phases, the brine will be treated with hydrochloric acid, and the phases will be remixed just before they enter the nozzle.

Mass flow rate and enthalpy will be measured on the separated vapor phase and the liquid phase after chemical treatment but before recombining. The vapor fraction (quality) can be determined from the flow rates of separated liquid and vapor. Conventional orifice meters will be used for single-phase-flow measurements. Calorimetric methods will be used to measure the enthalpy of the separated brine, which in combination with mass flow rates will allow determination of the total inlet enthalpy.

The condensing and cooling system is designed to maintain the nozzle test chamber at a constant pressure within the range of about 3 to 15 psia. This is accomplished by exhausting the nozzle chamber into a low-level barometric condenser and removing noncondensable gases with a vacuum pump. Variable backpressure is then obtained by a controlled air leak into the vacuum system. Thrust coefficients for a rectangular nozzle will be measured as a function of the backpressure for a series of nozzle inlet conditions. The inlet condi-

tions will vary with the wellhead pressure and the phase remix quality. The inlet pressure will range from about 250 psi to the well limit, while the inlet quality will be controlled between approximately 10 and 20%.

The choice of an equation of state for the isentropic flow calculation and the measurement of brine enthalpy and the vapor and brine mass flow rates will have a large effect on the accuracy of the thrust coefficient measurement. The experimental errors of each measurement are additive because the quantities appear as a product in the thrust coefficient equation. As a result of this, the field measurements of thrust coefficients will obviously be less precise than laboratory measurements. A preliminary estimate of the error band is about $\pm 15\%$. Because of the magnitude of the error, a flow test will be conducted before the performance tests to measure the pressure profile of a typical nozzle using brine. Comparison of the measured profile and the isentropic profile predicted by the assumed brine equation of state will provide preliminary information concerning the adequacy of this equation-of-state model.

An additional test will be conducted to help establish nozzle performance with brine. The field nozzle will be returned to the laboratory for testing in clean water, with inlet and exit conditions duplicating the field tests. A direct comparison can then be made between the two sets of test results.

Single-Nozzle System Test (Existing Wheel). Predictions of significantly increased wheel performance as a function of small droplet size have provided strong reason to focus the previously described experimental and analytical effort on reducing droplet size. Final confirmation of successful

droplet-size reduction will be obtained from a test of the new nozzle with the existing rotor to demonstrate improved wheel performance. A laboratory test of the improved nozzle in the nozzle box will first be performed to determine its thrust coefficient. The existing wheel test hardware will then be used with the improved nozzle, as in previous performance tests. Engine efficiency versus rotor speed will be determined, and wheel efficiency can be separated from nozzle efficiency.

Two-Phase-Flow Measurements. Determination of the performance of energy-conversion machines requires knowledge of the mass flow rate through the machine and the thermodynamic state points at inlet and exit. It is desirable to make direct measurements at the points of interest, if possible. However, in the case of two-phase flows, the tools for such measurements are not available.

Laboratory experiments have shown that it may be possible to determine flow rate by placing two meters in series—for example, two orifice meters or an orifice meter and a venturi. Continuing analysis of existing laboratory test data is planned for FY 1977.

Further development for direct measurement of two-phase flow rates and properties is not urgent, since the baseline brine-treatment concept requires phase separation, which will allow separate measurements by conventional devices.

A continuing effort on the evaluation of transducers for use in the hostile brine environment is a vital part of this subtask, particularly the pressure sensors that are used with the conventional devices.

G. L. Dittman

3.3 Alternative Energy-Conversion Systems

3.3.1 INTRODUCTION AND DESCRIPTION OF HYBRID CONCEPTS

In this discussion the term "alternative systems" means a combination of a liquid expander and one or two conventional vapor turbines. These hybrid systems combining a two-phase expander with vapor expanders are an improvement over conventional flashed-steam systems and an alternative to total flow and binary systems. The basic building

blocks for advanced flashed-steam systems (separators, scrubbers, and vapor turbines) are state-of-the-art technology, whereas the two-phase expander requires development.

This section describes an experimental radial-outflow reaction turbine (Fig. 3-26) that we are designing for laboratory evaluation and its potential

applications. The applications of the pure reaction turbine cover a broad range of wellhead conditions, from total flow for saturated water to an alternative system for one- and two-phase wellhead conditions.

We are interested in the development of the reaction turbine for three basic reasons:

1. It extends our total flow, two-phase turbine capability to low-enthalpy resources with water temperatures of up to 350°F (e.g., Idaho and Gulf Coast resources).
2. It can utilize the additional energy in compressed liquid (e.g., geopressured reservoirs).
3. When added to HT/HS or other two-stage flashed-steam systems, it can improve the overall conversion efficiency.

Fig. 3-26. Geothermal radial-outflow reaction turbine.

3.3.2 THE LLL GEOTHERMAL REACTION TURBINE

The LLL geothermal radial-outflow reaction turbine is distinguishable from other similar machines by virtue of hot water in the rotating ducts and two-phase steam reaction nozzles. The geothermal reaction turbine is shown in some detail in Fig. 3-26. Hot water is fed to the center of the rotating disk through a seal. The flow is then divided into separate radial ducts leading out to the reaction nozzles.

The nozzle configuration (Fig. 3-27) is a unique two-stage design. In the liquid nozzle most of the work done on the liquid is recovered, and a portion of the available thermal energy is converted into work in the two-phase steam nozzle. The step between the liquid nozzle exit and the steam nozzle entrance centerlines is designed to reduce "capture" of the liquid droplets on the steam-nozzle walls.

The design features and operational modes that are likely to make the LLL pure reaction turbine practical are the following:

1. Since only saturated or compressed liquid is admitted to the turbine, phase separation ahead of the steam nozzle is not a problem.
2. Fluid leaving the liquid nozzle is free from radial acceleration, and hence phase separation and resulting "capture" in the steam nozzle are minimized.
3. The two-stage nozzle permits efficient energy conversion over very large pressure ratios.

4. All proposed operational modes involve expansions for which the available energy is less than 40 Btu/lb, and therefore disk stresses can be kept within practical limits.

Fig. 3-27. Nozzle configuration.

3.3.3 TURBINE PERFORMANCE

The potential engine efficiency of the radial-outflow reaction turbine vs angular velocity is shown in Fig. 3-28. The steam conditions shown represent operation between the high- and low-pressure separators of an HT/HS two-stage flashed-steam power plant. Angles β and θ refer to steam and hydraulic nozzle angles with respect to radial lines. A family of performance curves is shown as a function of α ,

the capture term. This term represents the percent of the mass flow of liquid droplets at the nozzle exit that strikes disk surfaces and loses its relative velocity. Angular velocities beyond 2000 rad/sec would not be practical for the 16-in. disk diameter because of high stresses. An engine efficiency of 50% appears to be feasible at $\omega = 1500$ rad/sec (14,320 rpm) and $\alpha = 4\%$.

Fig. 3-28. Efficiency of radial-outflow reaction turbine engine. Conditions: 16-in.-diam rotor, 350-psia saturated liquid in, 20-psia exhaust (20% quality), slip of 60%. Nozzle efficiencies: liquid, 95%; two-phase steam, 75%.

3.3.4 DEVELOPMENT SCHEDULE

The development schedule for FY 1977 is shown in Fig. 3-29. A decision will have to be made on whether or not to proceed with turbine fabrication, after the completion of nozzle testing and evaluation. Depending on nozzle test results, the options available are as follows:

1. If the nozzle test results are favorable, proceed with turbine fabrication.

2. If the results are marginal, redesign the nozzles and test again.

3. If the results are unfavorable and no way can be seen to improve nozzle performance, the concept will have to be abandoned.

We expect, however, that the nozzle test results will be favorable and that the turbine can be tested near the end of FY 1977.

3.3.5 REACTION-TURBINE APPLICATIONS

Figure 3-30 compares the radial-outflow reaction turbine, used as a total flow expander for 300°F water, with the single-stage flashed-steam system. With a radial-outflow reaction turbine efficiency of

40%, the two systems are comparable; with an efficiency of 50%, there is a 25% increase in effective engine efficiency (system expander work divided by isentropic work between source and sink) over

Fig. 3-29. Fiscal year 1977 schedule for the development of the radial-outflow reaction turbine.

Total flow operation — effective engine efficiency = 46.6%

Single-stage flashed steam — effective engine efficiency = 37.4%

Fig. 3-30. The radial-outflow reaction turbine (RORT) in the total flow mode compared to the single-stage flashed-steam system at 300°F.

the flashed-steam system. Further gains in conversion efficiency for low-temperature resources are realized by the systems shown in Fig. 3-31. The reaction turbine teamed up with a vapor turbine shows a 12% gain in effective engine efficiency over the two-stage flashed-steam system. Another advantage of the hybrid system is its simplicity.

Figure 3-32 represents an advanced flashed-steam system for use with high-energy-reservoir systems (e.g., HT/HS geothermal wells with two-phase steam at the wellhead). The reaction turbine is used to expand liquid from the first separator to the second. This is also one of the more promising applications for the Lysholm expander. The Laboratory is currently testing a Lysholm expander in the laboratory to determine its suitability for hybrid use. Although a detailed economic study has not been made, the advanced system is expected to

pay for itself since the additional cost of the reaction turbine would be balanced against lower well costs (reduced mass flow rate) and extended reservoir life for a given power output. The system effective engine efficiency over a broad range of reservoir temperatures is shown in Fig. 3-33. Three curves are shown as a function of the two-phase expander (radial-outflow reaction turbine or Lysholm) efficiency. Zero percent represents the conventional two-stage flashed-steam system. Water rates for the three curves at the low- and the high-temperature ends are 191, 172, and 163 lb/kWh and 50, 46, and 43 lb/kWh, respectively. A significant improvement in performance is obtained by adding the reaction turbine to the two-stage flashed-steam system. System performance remains good over a broad range of wellhead conditions, including low temperature and low steam quality.

Hybrid system — effective engine efficiency = 53.3%

Two-stage flashed steam — effective engine efficiency = 47.7%

Fig. 3-31. Hybrid system containing the radial-outflow reaction turbine compared to the conventional double-flash process.

Fig. 3-32. The radial-outflow reaction turbine added to a double-flash system.

Fig. 3-33. Performance of advanced flashed-steam system.

3.3.6 SUMMARY

The radial-outflow reaction turbine offers considerable versatility in the conversion of geothermal energy into electrical power. It may be used as a total flow expander or added to a single-stage flashed-steam system for wellhead conditions of saturated or compressed liquid (e.g., Idaho and Gulf Coast resources). It may be added to the two-stage flashed-steam system for typical HT/HS wellhead conditions in order to increase the overall conver-

sion efficiency. Considerable improvement in performance is gained with only a small increase in complexity. The pure reaction turbine's inherent simplicity, ruggedness, and freedom from blade erosion make the machine a natural choice for the expansion of geothermal brine.

P. A. House

4. BRINE CHEMISTRY AND MATERIALS

4. BRINE CHEMISTRY AND MATERIALS

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4. BRINE CHEMISTRY AND MATERIALS

4.1 Introduction

This section describes progress during FY 1976 and FY 1976T toward developing brine-chemistry and materials-utilization technology for the high-temperature, high-salinity (HT/HS) brines of the Salton Sea Geothermal Field (SSGF). The objectives of the brine-chemistry and materials task group were twofold:

Technology Development Program: To demonstrate a method for scale and solids control and to establish a preliminary basis for materials selection

for the total flow impulse-turbine system.

Industrial Support Program: To define and implement a chemistry and materials program to support the Geothermal Loop Experimental Facility (GLEF) at Niland, California. This project is jointly undertaken by ERDA and the San Diego Gas & Electric Company.

A brief overview of both activities is given below. This is followed by a discussion of progress in each major task.

4.1.1 BRINE CHEMISTRY AND MATERIALS TECHNOLOGY FOR THE TOTAL FLOW IMPULSE TURBINE

A schematic diagram of the total flow impulse-turbine system, discussed in Section 3, is shown in Fig. 4-1 to illustrate principal brine-chemistry and materials issues. In the total flow system, wellhead brine is expanded through nozzles to convert the enthalpy of the brine into the kinetic energy of jets of high-velocity fluid. The jets then drive an axial-flow impulse turbine, which in turn drives an alternator to generate electricity.

Exploratory experiments during 1975 at the Sinclair No. 4 well test site in the Salton Sea Geothermal Field (see Section 5 for well locations) showed that the rate of scale deposition in test nozzles was about 1 mm/day. In addition, severe erosion of wear blades placed in the nozzle exhaust provided indirect evidence that solids were precipitating during nozzle expansion. These observations are consistent with the idea that the scaling and solids-precipitation processes are driven by the decreased solubility that accompanies cooling, and the fact that nearly all of the brine-temperature drop occurs in the nozzles. The production of suspended solids is undesirable because of increased erosion as well as possible plugging of injection-reservoir porosity.

Most of the brine-chemistry and materials effort was oriented toward solving the scaling and solids-deposition problems because it was obvious that the success of the total flow system or of any other conversion process for HT/HS brine was dependent on a solution to these problems. Of the various possi-

ble methods for scale and solids control, only two hold promise for simultaneously controlling both:

1. Brine modification to prevent precipitation of scale- and solids-forming species (i.e., acidification and oxidation).
2. Brine treatment to cause pre-precipitation of scale- and solids-forming species at wellhead conditions and to remove them before the brine enters the conversion system.

Other methods based on the prevention of scale accumulation (scrapers, flexing, boundary-layer isolation, scale-resistant surfaces, and threshold inhibitors) or periodic maintenance are less interesting because they do not solve the problem of solids entry into the conversion system. The second of the two methods listed above (pre-precipitation) was considered only as a backup alternative because of the advanced technology that would be required to remove the solids from the high-temperature wellhead brine. The effort was therefore principally concerned with the identification and testing of brine-modification methods to prevent scale and solids deposition, and with supporting tasks.

In anticipation of scale control by brine acidification, a task was established to provide a preliminary basis for selection of turbine materials. This effort was mainly focused on obtaining materials resistant to erosion/corrosion and stress corrosion and on preliminary testing in the brine environment. The principal candidates for turbine material were

Fig. 4-1. Simplified schematic of the total flow impulse-turbine system (only one nozzle shown for simplicity).

titanium-base alloys because of their favorable strength-to-density ratio and their relative resistance to environmentally induced failure in aqueous media.

As discussed in this report, the principal brine-modification method investigated was acidification. The total flow system is particularly suited to this scale-control approach since all of the temperature drop occurs in the nozzle, and the downstream plant components (turbine case, downstream separators and piping, and injection casing) need only

be resistant to acid-brine flows at the low temperature ($\sim 50^{\circ}\text{C}$) of nozzle exhaust. Because of this potential for using relatively low-cost low-alloy steels or polymeric materials for downstream components, tasks for evaluating low-alloy steels and polymeric materials for this application were initiated. Acidification at or near the nozzle would limit the need for using the relatively expensive materials required for acidified-brine flows at wellhead temperatures (up to 250°C). Thus capital costs for acid-brine-handling materials at elevated temperatures would not be prohibitive.

4.1.2 CHEMISTRY AND MATERIALS SUPPORT FOR THE GEOTHERMAL LOOP EXPERIMENTAL FACILITY

A condensed process flow diagram of the GLEF at Niland, California, is given in Fig. 4-2. The purpose of the GLEF project is to develop the performance data and brine-chemistry and materials information necessary to help provide a basis for a decision by FY 1979 to build a hybrid flashed-steam/binary cycle demonstration plant.

The GLEF incorporates a sequential four-stage flash process. The steam is scrubbed in bubble-cap

tray towers and then directed through heat exchangers, where the heat is transferred to a secondary working fluid. In the present operation, water is used as the working fluid and is expanded across a throttling valve to simulate the pressure drop across a turbine. The steam condensate can be cascaded to the next stage, combined with the spent brine, or used for spray pond makeup.

The FY 1976 and FY 1976T objectives of the

Fig. 4-2. Process flow diagram, Geothermal Loop Experimental Facility, Niland, California. (After the Ben Holt Company diagram for the San Diego Gas & Electric Company.)

brine-chemistry and materials component of the LLL Industrial Support Program included the following:

1. Characterization of brine and steam flows through the GLEF.
2. Development and use of an in-process scale-surveillance technique.
3. Development and use of sampling methods for suspended solids.
4. Baseline characterization of the physical and chemical nature of the scale and solids produced.
5. Definition of a GLEF operational plan to identify the optimum mode of operation for minimizing scale and solids deposition.
6. Implementation of a plant materials test and evaluation program.

4.2 Scale Studies

Evaporative concentration and cooling of depressurized hypersaline brine from the Salton Sea Geothermal Field results in rapid deposition of siliceous scale on surfaces exposed to brine. The scaling problem is intensified by the high flow rates typical of producing wells in the SSGF (nominally 1.8×10^5 kg/hr) because even a minuscule mass transfer (0.1 wt%) of dissolved constituents from brine to scale is sufficient to rapidly clog flow lines and render valves and other critical components of energy-conversion systems inoperable.

Since a primary program goal was the development of effective scale-preventive measures, it was obvious that some insights into scaling

The plant materials program was designed to emphasize materials studies applicable to possible future operation of the GLEF in an acidified-brine mode for scale and solids control. In particular, initial feasibility studies of prescaling as a technique for limiting the corrosion rate of carbon steel carrying acidified brine were begun in 1976. This approach may allow GLEF operation with acid-brine flows for an appreciable time without unacceptable corrosion. Furthermore, a program for testing a wide range of potential acid-brine-resistant materials (titanium alloys, Inconel 600, etc.) was planned for mid-1977. Such materials are being evaluated for possible use in the GLEF as linings to permit extended operation with acidified brine.

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phenomenology would be required. In view of the complexity of natural brines at high temperatures and pressures, a field-oriented experimental program was initiated with supporting laboratory studies of scale compositions and microstructures. The results of these activities were supplemented by appropriate literature reviews in order to identify effective control measures that might subsequently be evaluated in the field. In connection with the Industrial Support Program, a method for in-process scale surveillance was developed. Also initiated was a program to evaluate the scaling characteristics of the GLEF as a function of operational mode.

4.2.1 SCALE COMPOSITION AND MICROSTRUCTURES

Typical wells at the Salton Sea Geothermal Field produce two-phase mixtures of liquid plus steam at temperatures of 200 to 250°C and pressures of 200 to 450 psig. Dissolved solids at the wellhead range between 15 and 30% by weight. Although the brine is primarily a mixture of sodium, potassium, and calcium chlorides, trace constituents like silicon, heavy metals (e.g., iron, lead, copper, zinc), and sulfur account for the bulk of scale deposits and precipitates carried in high-velocity streams as suspended solids.

Siliceous scales formed at temperatures of 100°C or higher are composed of a variety of well-crystallized heavy-metal sulfides, with some metallic silver, entrained within or growing upon a

fine-grained, massive to microlaminated, iron-rich amorphous silica matrix. It is not unusual to also observe relatively high concentrations of aluminum (up to 6 wt%) in the matrix. In general, the silicon/iron mole ratio usually varies between 0.5 and 1.5 at temperatures higher than 100°C, but it trends rapidly toward a relatively pure silica end member in deposits from low-temperature (<100°C) brine effluents. Lower temperature scales, characteristic of those found in injection flow lines, consist of interbedded massive amorphous silica and calcium-, iron-, and manganese-rich carbonates. Carbonate deposition is promoted by the addition of ammonia- and carbonate-bearing condensate to brine effluents.

The sulfides are commonly observed in the form of dendritic structures oriented perpendicular to the direction of brine flow, as massive deposits growing on thin basal silica-rich layers, as small crystallites randomly dispersed throughout a silica-rich matrix, or interbedded as discrete bands within the matrix material. Sulfides are never observed adhering directly to metallic or polymeric substrates; basal scale layers are always either silica-rich or intimate intergrowths of amorphous silica and sulfide crystallites (Figs. 4-3, 4-4, and 4-5). These relationships suggest that initial silica deposition is required for the subsequent adhesion of sulfides. Sulfide morphologies are also indicative of diffusion-controlled growth rather than precipitation and subsequent incorporation in scale of large sulfide crystals ($\geq 1 \mu\text{m}$ in diameter). Once sulfide nucleation occurs within the silica matrix, further growth is sup-

ported by the diffusion of metal and sulfide ions at the scale-brine interface.

Additional evidence of the *in situ* growth of sulfides was provided by filtration experiments carried out at the Magmamax No. 1 site (see Section 5). Sulfides filtered from separated brine consisted of submicron PbS cubo-octahedra. However, scales formed from the same brine were enriched in CuFeS_2 , Cu_2S , and ZnS , as well as PbS, with morphologies ranging from relatively large crystallites up to $10 \mu\text{m}$ in diameter to massive deposits without observable grain boundaries.

Scale analyses by electron microscopy revealed that the silica matrix presents an ideal environment for sulfide nucleation, as it is comprised of 1- to 5-nm colloidal silica particles aggregated in the form of a porous gel-type network. Micrographs of

Fig. 4-3. Electron-microprobe analysis of scale formed on a polymeric nozzle. The matrix material (gray to black) is iron-rich amorphous silica and is sulfide deficient. The white grains are copper sulfides. Scale adhesion was promoted by the deposition of silica. Elemental analysis for region A (indicated by the vertical bar) and region B (indicated by the horizontal bar) is shown at right.

Fig. 4-4. Optical micrographs of typical morphologies near substrate-scale interfaces. Scale adhesion is promoted by the deposition of silica. Sulfides are never observed adhering directly to substrates.

Fig. 4-5. Optical micrographs of scale. Top: scale deposited in a plain carbon-steel elbow upstream of the GLEF first-stage separator. Scale adhesion is promoted by iron-rich amorphous silica that has infiltrated the magnetite-hematite corrosion layer. Subsequent deposits are a mixture of PbS (white) in an iron-rich silica matrix (black). Bottom: scale deposited in a titanium alloy nozzle: CuFeS_2 (white) in an iron-rich silica matrix (black). Scale adhesion was promoted by the deposition of sulfide-deficient silica.

acid-leached and nonleached scales and a schematic interpretation of the silica structure are provided in Figs. 4-6, 4-7, and 4-8. Ultrastructure analyses of low-temperature ($<100^\circ\text{C}$) scales indicate that silica deposited in the form of colloidal particles 56 to 80 nm in diameter (Fig. 4-9). The structures observed in scale were identical with those seen in silica gels formed from Dupont Ludox 25-nm colloidal silica (Fig. 4-10).

On the basis of these observations, it was hypothesized that the key to scale control, even in cases where sulfides comprise the bulk of deposits, is suppression of silica deposition. However, since the relationship between sulfide nucleation and the destabilization of silica sols was not known, it seemed appropriate to also consider the use of sulfide scale inhibitors as a means of depressing silica deposition rates.

Fig. 4-6. Transmission electron micrograph of the silica fraction of scale deposited in nozzles. Scale samples were etched with hot hydrochloric acid to leach sulfides. This treatment does not affect the silica structure. Thin edges of grains were then examined in the transmission electron microscope. The silica is in the form of a porous gel-type network. Gray areas are silica, white areas are porous. Individual silica particles cannot be resolved but are probably 1 to 5 nm in diameter.

Fig. 4-7. Transmission electron micrographs of acid-leached (left) and nonleached (right) fragments of scale formed in nozzles. Both samples exhibit a porous network-type structure characteristic of aggregated colloidal silica.

4.2.2 SCALING RATES

Scaling rates were measured at three sites in the Salton Sea Geothermal Field (Sinclair No. 4, Magmamax No. 2, and Magmamax No. 3) by flowing mixed-phase brine, at wellhead conditions, through long (~70 cm), gradually tapered expansion tubes instrumented with evenly spaced thermocouples. The maximum temperature gradient between the inlet and exhaust regions of these tubes was on the order of 3°C/cm, depending on the production characteristics of the geothermal well at which an experiment was carried out (Fig. 4-11). At the completion of a run, the tubes were returned to the laboratory for analysis. Polished transverse metallographic sections, cut from each thermocou-

ple position, were then used for scale-thickness measurements, scale mineralogy by reflected-light microscopy, and quantitative chemical analyses by electron-microprobe techniques. In this way, the average scaling rate was correlated with the temperature of deposition and the solid phases that formed scale.

Magmamax No. 2 and No. 3 are injection wells; Magmamax No. 2 was shut in immediately after its completion, but Magmamax No. 3 was used for some extended period as a disposal well prior to being shut in. It was not possible to adequately flow either well before the start of the scaling-rate experiments, because facilities were not available for

Fig. 4-8. Schematic interpretation of silica microstructure.

Fig. 4-10. Transmission electron micrograph of a silica gel formed from Dupont Ludox 25-nm colloidal silica (1 mm = 8.34 nm).

Fig. 4-9. Transmission electron micrographs of low-temperature ($<100^{\circ}\text{C}$) silica-rich scale deposited in the downstream flange of the GLEF injection pump. Silica is in the form of colloidal particles 56 to 80 nm in diameter (see Fig. 4-10).

Fig. 4-11. Typical temperature gradient in expansion tube for scaling rate tests (Magmamax No. 2 geothermal well).

storing more than about 20,000 gallons of brine effluents per well. There was therefore no way to determine whether the brines produced were representative of *in situ* fluids. Most likely they were not. An additional problem was encountered at the Magmamax No. 3 site, where the bottom of the well was found to be filled with a smectite sludge several hundred feet thick. This material is believed to have originated as an alteration product of bentonitic drilling mud or injected solids. The sludge was removed by flowing the well at a low rate for several days and trucking excess brine effluents to the disposal ponds at the Sinclair No. 4 site, 1.6 km to the south. Scaling-rate data for Sinclair No. 4 brine are considered to be most reliable because the well was flowed, on a semicontinuous basis, for several months before the start of the experiment. Whereas the Magmamax wells had to be throttled back to reduced flow rates, the large brine-storage capacity of the ponds at the Sinclair No. 4 site permitted higher flow rates (up to approximately

1.8×10^5 kg/hr). Flow rates through the expansion tubes, however, were identical for all of the experiments (0.9 kg/sec).

Operating conditions and experimental results are summarized in Table 4-1. The highest scaling rates were encountered at Sinclair No. 4, even though brine from the Magmamax No. 2 well had the highest silica content. This anomaly is believed to be a result of suspended solids (submicron clays and colloidal silica) recovered and analyzed with brine from Magmamax No. 2. The average diameter of these particles may have been too large to permit their deposition as scale from high-velocity streams, so that measured scaling rates were essentially identical with those obtained from Magmamax No. 3 brine with a total silica content of less than 300 ppm.

Average scaling rates were computed in terms of scale mass deposited per unit time, with corrections made for the increased cross-sectional area of the expansion tubes downstream from their inlets.

Table 4-1. Results of slow-expansion scale-deposition experiments

Parameter	Site		
	Sinclair No. 4	Magmamax No. 2	Magmamax No. 3
Depth (m)	1219	1052	1036
Total dissolved solids (wt%)	30.0	24.4	17.8
SiO ₂ (ppm)	594	877	217
Iron (ppm)	1575	1910	Not available
Expansion tube flow rate (kg/sec)	~ 1.4	~ 1.4	~ 1.4
Quality (%)	15	10	10
Run time (hr)	5.75	1.83	3.00
Temperature (°C):			
Inlet	240	195	174
Exit	110	99	82
Pressure (psig):			
Inlet	425	230	200
Exit	1 atm	1 atm	1 atm
Scale thickness (μm):			
Throat	150	12	8
Exit	2000	29	56
Average scaling rate (μm/hr):			
Throat	26	7	3
Exit	348	16	19
Scale composition:			
Iron-rich amorphous silica	High	High	High
Copper sulfides	High	High	Trace
Lead sulfides	Trace	High	High

These data are summarized in Fig. 4-12. Rates have been normalized with respect to scale thicknesses measured at the exhaust end of each tube to permit plotting all of the data on a single graph. The shapes of the three curves are identical and can be interpreted in terms of several independent scaling processes operating simultaneously.

The flat, high-temperature portions of the rate curves are indicative of thin layers of scale that extend back toward the inlet regions of the expansion tubes. Although these scales may have formed at temperatures too high for the solubility of amorphous silica to have been exceeded, all of the scales contain silica. We suggest that this scale represents steady-state deposition from mixed-phase brine and is induced by the partial evaporation of surface films and brine droplets carried in the vapor phase. Each measured rate is actually the result of two separate processes: the deposition of silica and the deposition of heavy-metal sulfides. Slight differences in the relative rates of these processes account for the differences in the observed resultant curves.

The sharp break and rapid increase in scaling rate profiles that occurred at lower temperatures are reflected by an increase in the silica content of the scale, with a corresponding decrease in the relative abundance of sulfides. These inflection points can be interpreted as the temperature at which the solubility of amorphous silica is exceeded. The Sinclair No. 4 inflection point occurred at the highest temperature because the brine was most concentrated with respect to dissolved silica and iron. Significant differences in scale mineralogy were also observed. Sinclair No. 4 scale was enriched in copper sulfides, whereas the primary sulfide in Magmamax scales was galena (PbS).

Fig. 4-12. Average scaling rates as a function of temperature: (a) 2° expansion tube experiment of Magmamax No. 3 (3 hr); (b) normalized scaling-rate curves.

4.2.3 SCALE CONTROL BY BRINE MODIFICATION

A review of the aqueous chemistry of silicon was completed in order to determine the feasibility of stabilizing brines saturated with amorphous silica by adding an appropriate chemical reagent. It was found that the solubility of silica increases with increasing temperature but is independent of solution pH up to a pH of about 8.5. Under these conditions, the principal aqueous species is the uncharged monomeric molecule of silicic acid, H_4SiO_4 . At higher pH, silica becomes more soluble because the

dissociation products of silicic acid are soluble. It was concluded, however, that it was not feasible to solubilize silica by increasing brine pH, because massive precipitation of carbonates, sulfides, oxides, hydroxides, and silicates would occur in the pH interval between 5.0, the nominal wellhead brine pH, and 8.5. Attention was then directed to mechanisms governing silica precipitation.

Complex polymerization-condensation kinetics are involved in the precipitation of amorphous

silica. In supersaturated solutions, monomeric silicic acid polymerizes by forming siloxane bonds and splitting off water molecules, ultimately resulting in the production of colloidal particles. Since colloidal silica particles in solutions with pH values greater than about 2 have slight negative surface potentials, high salinities tend to promote destabilization and rapid aggregation. However, these reactions are all pH dependent. Although data are lacking for highly concentrated brines like those produced at the SSGF, published studies dealing with lower salinity fluids suggest that acidification of geothermal brines might be an effective method of inhibiting silica deposition. For instance, the standard technique for measuring dissolved-silica concentrations colorimetrically involves sample acidification immediately after collection to minimize or prevent polymerization.

Another potentially useful scale-control procedure is based on the premise that an oxidizing agent (e.g., oxygen or hydrogen peroxide) can be used to increase the oxidation-reduction potential of brine that is still at wellhead conditions. This process should minimize the deposition of heavy-metal sulfides because the sulfide ion would be converted to free sulfur. Furthermore, if sulfide nucleation is related to the aggregation of colloidal silica, a significant reduction in silica deposition rates might also be realized.

The two scale-control methods identified above, acidification and oxidation, would increase the corrosion rate and aggravate other corrosion-induced material-failure mechanisms. In the total flow system, however, the reagent would be added immediately upstream of the nozzle, and thus only a very limited quantity of expensive material (such as Hastelloy C-276 or titanium alloy) would be needed to handle acidified- or oxidized-brine flow at wellhead temperatures. After the modified brine is expanded, the temperature is low enough to permit consideration of polymeric materials or low-alloy steels (e.g., for turbine case and downstream piping). In the case of more conventional conversion processes based on steam flashing, for example, the use of relatively expensive materials could be economical if applied as linings on piping and vessels for the brine-handling part of the plant.

A substantial effort was allocated in 1976 to test and evaluate brine-modification methods (only pH reduction was evaluated in 1976) because of the very great need for scale and solids control in SSGF brines and because it was judged that an economic solution to the materials problems could be found. Emphasis was placed on evaluating the economics of the method as well as its effect on scale and solids production. The results of the 1976 test program are discussed in subsequent sections.

4.2.4 SUMMARY OF SCALING MECHANISMS AND SCALE-CONTROL STRATEGIES

Sulfide Scaling Mechanisms

Sulfide scaling mechanisms can be summarized as follows:

1. Sulfides do not deposit directly on polymeric or metallic substrates.
2. Initial silica deposition is required before sulfides will adhere.
3. Nucleation of sulfide crystallites occurs within the porous silica-rich matrix structure.
4. Large sulfide nuclei ($>1\ \mu\text{m}$) that precipitate from brine do not subsequently become incorporated into high-temperature scales ($>100^\circ\text{C}$).
5. Continued growth of sulfides is supported by the diffusion of metal and sulfide ions at the brine-scale interface.
6. Sulfide scaling may be eliminated if silica deposition can be prevented.

Silica Scaling Mechanisms

Silica deposition can occur from brines that are, on the average, undersaturated with respect to the solubility of amorphous silica because flashing causes rapid formation of colloidal silica (1 to 5 nm in diameter) as brine droplets and surface films evaporate.

Depolymerization of colloidal silica is not rapid, especially after sol aggregation induced by the formation of metal adsorption complexes and further cementation by the deposition of soluble silica species. Adsorption complexes can also include heavy-metal sulfide nuclei, and hence suppressing sulfides by modifying brine pH might also lower silica deposition rates.

When brine becomes, on the average, supersaturated, silica deposition rates increase rapidly.

Scale adhesion is promoted by siloxane bonding to substrates and by the formation of coherent monolayers.

Scale-Preventive Measures

Two primary scale-control strategies, based on chemical modification of high-temperature brine, were defined.

Acidification. Brine acidification may be effective because brine pH controls the kinetics of silica

polymerization and silica-sol stability. If silica deposition is prevented, sulfide nucleation and growth on substrates cannot occur. In addition, the precipitation of heavy-metal sulfides and carbonates is limited at lower pH.

Oxidation. Because oxidation converts the sulfide ion to free sulfur, it thereby prevents the formation of heavy-metal sulfides. Silica deposition rates may also be reduced if heavy-metal sulfide adsorption complexes promote the destabilization and aggregation of colloidal silica.

4.2.5 SCALING CHARACTERISTICS OF GLEF

Scale Surveillance Through the Use of Radiographs

One of the early objectives of the LLL Industrial Support Program is to characterize scaling rates as a function of operational mode in the GLEF, shown in schematic form in Fig. 4-2. Such data are required to assess the economic feasibility of operating a flashed-steam system with shutdown periods for periodic scale removal. Internal methods, such as probes or depth gauges, would in themselves promote local scaling and not give a true scaling rate on GLEF piping and components. Thus radiographic techniques were investigated as external, *in situ* means of tracking scaling rates.

A 1.2-MeV, 15-Ci cobalt-60 source was used after it was found that an 0.4-MeV iridium-192 source did not provide sufficient penetration. The principle is quite simple. The source and a film plate are positioned on opposite sides of the subject. The differences in the gamma absorptivity of brine, scale, and steel result in sufficient contrast to produce a radiograph from which projected thicknesses can be measured. A 12- by 16-in. film plate is used and is the limiting factor in subject size. Source strength, exposure time, solid source angle, film and source position, and opacity of the subject are all important factors in the quality of the radiograph. In general, scale deposition on the inside walls of pipes, fittings, and stationary valves can be viewed radiographically with a resolution of about 1 mm.

Figure 4-13 is a radiograph reproduction of a 10-in. pipe that receives brine flow from the first-stage separator. Scale thickness as determined from this radiograph was 25 mm. Table 4-2 lists the scale thickness at various sampling points in the GLEF,

as determined by radiographs taken at the end of the first operational phase totaling 300 hr. Also listed are the measurements at or near the radiographic site.

Fig. 4-13. Reproduction of radiograph of a 10-in.-diameter pipe downstream of the first-stage separator in the GLEF. Inner scale layer is about 25 mm thick.

Table 4-2. Scale thickness as determined by radiography, GLEF, May-June 1976

Sampling point	Scale thickness by radiograph (mm)	Actual scale thickness in vicinity of radiographic site (mm)
Output brine pipe:		
First-stage separator	2	1-3
Second-stage separator	< 1	1-3
Fourth-stage separator	15	16-17
Downstream piping:		
Second-stage control valve	5	1-3
Injection pump	7	12-16
Fourth-stage control valve	1	< 1
Brine level control valve, injection pump	10	12-16
Piping just upstream of injection wellhead, Magmamax No. 3	< 1	< 1
Piping near production wellhead, Magmamax No. 1	2	Not measured
Upstream pipe elbow, first-stage control valve	< 1	< 1

Radiographs taken later, after additional hours of operation had been logged, indicated continued layered scale buildup inside the brine piping. The layers are believed to result from plant stoppages followed by cooling and/or drainage of the brine from the lines. The ripple texture is probably caused by turbulent flow conditions in the pipe. These results show that radiography is a reliable method for the in-process surveillance of scale buildup in full-size pipes.

This technique continues to be used periodically to measure scale thicknesses in GLEF piping as a means of determining scaling rates without affecting the process flow streams.

Recently, pipe spools containing venturi-type flowmeters were installed in the brine effluent piping. We also used these spools for scale monitoring and inspection. Between December 15, 1976, and January 31, 1977, the GLEF total run time without condensate recombination was 934 hr, the highest utilization to date. During this period, scale thickness was measured in the above-mentioned spools following first-, second-, and third-stage separations. The data are presented in Fig. 4-14. The set of data at 660 hr was obtained by radiography and the set at 934 hr by direct measurement. The spools were clean at the start of this operation on December 15. Although stage temperature decreased from 185°C in the first to 149°C in the second and 118°C in the third, no correlation between temperature and scaling rate is apparent. The scale-deposition rate appears to be roughly constant during this

period. Scale mineralogy and chemical composition analyses were not available at the time of this writing. However, previous analyses on earlier scale sampling have been described. This type of scaling data together with cleaning costs being obtained by

Fig. 4-14. Scaling rates in GLEF brine effluent pipes. Operation with Magmamax No. 1 brine without condensate decontamination.

the San Diego Gas & Electric Company will be used to assess the economic feasibility of periodic scale removal.

Scale Production in the GLEF

Because of numerous plant upsets, scale deposited on the walls of GLEF piping and equipment during operation represents scale produced over a wide range of operating conditions. These scales may or may not represent the amount or type of scaling that would occur in the GLEF during a prolonged period of steady operation. Nevertheless, the mineralogical and chemical analyses of these scales add greatly to our understanding and ability to interpret the interaction of scaling with brine chemistry, changes in brine temperature and pressure, and other conditions imposed by a multistage flash process.

Frequent interruptions in GLEF operation resulted in alternating bands of light- and dark-colored layers in the scale, as illustrated in Figs. 4-15 and 4-16. In the separators there were at least two scaling regions. Above the normal operating liquid level, scaling on the walls of the separators was a few millimeters thick compared to approximately 5 to 10 mm in the lower half, which was exposed to the liquid. This variation is not surprising in that the upper half of the separators is exposed to relatively clean steam with entrained brine plus an undetermined amount of flashing that takes place internally. The fact that continuous drainage can occur helps to reduce the buildup of scale in the upper half of the separator. Instead of continuously building up, scale continuously flakes off the wall, accumulating on the bottom of the separators.

As expected, brine scaling in the steam scrubbers was minimal, although a layer of corrosion products was apparent, not only on scrubber surfaces but on other steel surfaces as well. These corrosion products become an integral part of the brine scale.

The heaviest scaling occurred in the brine effluent piping of the fourth-stage separator and in points beyond. Brine from the fourth stage flows to the injection pump, which was heavily scaled. Just downstream of the injection pump, 12 to 16 mm of scale was observed at 300 hr on the walls of the 10-in. discharge pipe. At approximately 100 m further downstream in the surface-injection piping, heavy scaling was still evident in the butterfly valves used to isolate short bypass spool sections (Fig. 4-17). Several hundred feet of 10-in. injection piping, used to discharge spent brine from the

facility, contained 7 to 8 cm of scale accumulated over 2400 hr of operating time. The scale thickness decreases with distance in the approximately 1 km of surface-injection piping. The piping near the injection well was not heavily scaled. Apparently either the amount or the adherence of scale-forming constituents decreases as the spent brine passes through about a kilometer of surface-injection piping. This does not imply that the brine is depleted of suspended solids. As it reaches the injection well, the spent brine does indeed contain a considerable amount of suspended solids, as described in Section 4.5.

Scale Composition and Mineralogy

Scale samples were collected and analyzed periodically during the 2400 hr of GLEF operation. Temperatures and pressures at sampling points in the GLEF can be estimated from the data given in the process flow diagram. It should be emphasized again that the operating conditions at every location were highly variable.

In the mixed-phase brine immediately downstream of the first-stage control valve, where large temperature and pressure drops occur, the scale deposited on the pipe walls was predominantly a galena crystalline phase. The galena was dispersed in an iron-rich amorphous silica matrix. This scale could be chipped off the pipe wall in small flakes with moderate effort. The thickness was approximately 2 mm, the coloring gray to black, and the scale quite hard and brittle. The underlayer consists of magnetite/hematite—steel corrosion products. Galena is by far the main sulfide mineral found in the Magmamax No. 1 scale, whereas scale from the Sinclair No. 4 well and No. 1-IID well were mainly copper sulfides, bornite, and digenite, also dispersed in an iron-rich amorphous silica matrix.

Scale found in the lower half of the first- and second-stage separators was primarily an iron-rich amorphous silica, with galena present as the principal crystalline phase. There was much less galena than in scale deposited just downstream of the first-stage control valve. The high iron content may be in part mixed corrosion products. These scale samples are light brown to black in color, softer than the galena-rich scale, and when lightly ground resemble fine-grained dirt. This kind of scale also coats the separator brine effluent lines as described above and at a rate illustrated in Fig. 4-14.

In the third-stage separator and in locations further downstream, low-temperature-scaling species predominate—namely, amorphous silica

Fig. 4-15. Scale from the fourth-stage separator in the GLEF. Sample M1-VII-3, June 23, 1976. Thickness of sample, 9 mm.

Fig. 4-16. Scale from injection-pipe flange connection to output of injection pump, GLEF. Sample M1-P2-DS-1, June 17, 1976. Thickness of sample, 12 mm. This sample represents scale buildup after approximately 4 mm was scraped from the wall earlier in the operation. Total thickness of undisturbed deposits was 16 mm.

Fig. 4-17. Scale in butterfly valve (10-in. diameter) isolating short bypass pipe spools in reinjection line about 100 m downstream of the injection pump in the GLEF, after approximately 300 hr of operation.

deposited from a solution that has reached supersaturation. For the most part the scale is softer and layered. The dark scale consists of halite intermixed with an iron-rich amorphous silica. Trace amounts of galena may be present. The thick lighter layers consist of amorphous silica and halite. Large volumes of ponded brine from the facility's emergency brine pond were pumped into the fourth-stage separator on at least two instances because the separator was a convenient point of entry to the injection pump. How this affected scaling in the fourth stage and beyond has not been established.

Downstream of the injection pump and approximately 400 m beyond in the piping, the scale is a light, highly layered, silica-rich deposit as much as 8 cm thick after a total of 2400 hr of cumulated operation. It should be noted that at times the condensate from the first-, second-, and third-stage heat exchangers was combined with the brine at the input to the injection pump. Analysis of the condensate shows amounts as high as 1440 ppm (as CaCO_3) of CO_3^{2-} and/or HCO_3^- , which very likely contributed to the presence of the carbonate phase in the dark-layered scale; the carbonate phase consisted of kutnahorite $[\text{CaMn}(\text{CO}_3)_2]$ in an iron-rich amorphous silica matrix. Calcite-aragonite was also detected in scale at locations where steam condensate may have contacted the brine, especially in the impellers and bowls of the injection pump, which uses fourth-stage steam condensate as shaft-bearing purge water. Barite is present also as a result of the reaction of sulfate in irrigation water used to prime the well and barium in the brine.

The scale collected from the steam scrubbers showed a high iron content, which is consistent with visual observation of surface corrosion in the scrubbers. There was no brine-type scale of any significance in the scrubbers. Magnetite and hematite have been detected in scale at other locations in the facility, generally as the scale underlayer adjacent to steel surfaces.

Table 4-3 lists the elemental composition of scale samples from the GLEF. Samples collected after

Table 4-3. Composition of scale deposited in the GLEF, measured by atomic absorption and/or wet chemical analysis, May-June 1976

Element	Composition (wt%)						
	M1-PV301-			M1-V11-3A		M1-P2-DS-2B	
	DS-1	M1-V4-2	M1-V7-2	"Dark"	"Light"	"Dark"	"Light"
Silicon	7.38	14.17	14.93	16.04	20.30	17.79	15.28
Iron	10.36	22.50	9.94	9.39	1.24	8.87	0.73
Manganese	0.77	1.38	1.68	1.84	0.27	2.68	0.12
Calcium	0.09	0.27	0.99	0.30	0.44	1.02	0.04
Lead	43.90	6.70	5.10	0.45	0.16	0.54	0.07
Sodium	0.56	2.89	4.09	2.77	2.54	1.36	2.60
Potassium	0.32	0.80	0.65	0.75	0.49	0.47	0.53
Aluminum	0.26	0.27	0.22	0.018	0.018	0.015	0.017
Zinc	0.05	0.76	0.82	0.38	0.09	0.55	0.04
Copper	1.56	0.10	0.15	0.13	0.081	0.11	0.097
Barium	<0.005	<0.005	0.26	0.04	0.67	0.17	0.24
Sulfur	5.11	1.33	0.56	0.044	0.06	0.10	0.043
Antimony	1.21	0.10	0.06	0.02	<0.005	0.04	<0.005
Magnesium	0.054	0.24	0.095	0.017	0.012	0.009	0.008

additional run time had similar compositions. The sampling points are described in Table 4-4.

Table 4-5 lists the weight percentages, normalized to 100%, of ten major scale constituents found by wet chemical analysis in several scale samples and in the brine. The degree of fractionation of these elements from the brine is clearly indicated. The scale samples were highly enriched in lead, iron, and silicon and depleted in calcium, with respect to the composition of the brine. Silicon enrichment increases from upstream to downstream conditions, whereas lead decreases. The iron content of the scale appears to be fairly constant in all positions, except for the light-colored portion of the scale in samples M1-V11-3A and M1-P2-DS-2A. Since samples M1-V11-3 A/B and M1-P2-DS-2 A/B were separated in position by only the injection pump, it is not surprising that the two lighter colored samples are very similar in composition, as are the two darker portions of these two samples. Sodium and potassium were excluded from Table 4-5 because it is believed that their presence in the scale is due to conditions not usually encountered during normal, continuous operation.

It is of interest to calculate the maximum amount of scale that could be deposited at some position in the GLEF, provided we can assume that all the scale is identical in composition with the

scale sample. The maximum amount of scale per unit weight of brine is

$$M_s \leq \frac{X_b^i}{X_s^i}, \quad (4-1)$$

where M is the mass of scale per unit mass of brine, X_b^i is the weight fraction of species i in the brine, and X_s^i is the weight fraction of species i in the scale.

The most enriched species in the scale is i . For example, from Table 4-5, the i th species is lead for sample M1-PV-301-DS-1, giving $M_s = 0.00018$; iron for sample M1-V4-2, giving $M_s = 0.0011$; and silicon for the remainder of the samples, giving $M_s = 0.0010$ to 0.0014 . Copper and aluminum were not considered because of their low concentration in the brine. The scale mass that adheres to GLEF equipment and piping is but a small fraction of the suspended solids and a minute fraction of what is available in the brine.

Most of the suspended solids are injected. The actual mass distribution of specific species in the deposited scale and in the solid precipitates with respect to their position in the GLEF is difficult to determine even during steady operation. A prolonged period of steady operation will better enable us to determine the rate of scale production, the scale composition, and the temperature and pressure relationships associated with the principal scaling phases.

Table 4-4. Scale samples taken in the GLEF facility

Sample No.	Sampling date	Sampling point
M1-PV301-DS-1	6/22/76	6- to 16-in. expansion pipe downstream of PV301, first-stage control valve
M1-V4-2	6/23/76	Bottom, first-stage separator
M1-V7-2	6/23/76	Bottom, second-stage separator
M1-V11-3	6/23/76	Middle, fourth-stage separator
M1-P2-DS-2	6/17/76	Connecting pipe flange to injection pump output
M1-PV-301-US-2	6/22/76	Block valve upstream of first-stage control valve
M1-V8-2	6/22/76	First-stage scrubber, bottom tray
M1-LV714-DS-1	6/22/76	Downstream, fourth-stage control valve
M1-V9-2	6/22/76	Second-stage scrubber, bottom tray
M1-RJ-3	6/30/76	Injection wellhead pipe
M1-V11-2	6/22/76	Bottom, fourth-stage separator
M1-RJ-2	6/22/76	Injection line, second bypass spool
M1-LV711-DS-1	6/22/76	Downstream, second-stage control valve
M1-MX3-1	6/23/76	Downhole pressure-sensing tubing, Magmamax No. 3

Table 4-5. Normalized concentration of 10 chemical constituents of scale deposited in the GLEF, May-June 1976

Sample No.	Concentration (wt%)									
	Si	Fe	Mn	Ca	Pb	Al	Zn	Cu	Ba	Mg
Magmamax No. 1 brine	0.93	1.18	3.17	91.80	0.36	<0.005	1.66	0.005	0.54	0.37
M1-PV301-DS-1	11.45	16.08	1.20	0.14	68.14	0.40	0.08	2.42	<0.01	0.08
M1-V4-2	30.54	48.50	2.97	0.58	14.44	0.58	1.64	0.22	<0.01	0.52
M1-V7-2	43.67	29.08	4.91	2.90	14.92	0.64	2.40	0.44	0.76	0.28
M1-V11-3B, dark	57.07	32.83	6.43	1.05	1.57	0.06	1.33	0.45	0.14	0.06
M1-V11-3A, light	87.20	5.33	1.16	1.89	0.69	0.08	0.39	0.35	2.88	0.05
M1-P2-DS-2B, dark	56.02	27.93	8.44	3.21	1.70	0.05	1.73	0.35	0.54	0.03
M1-P2-DS-2A, light	89.87	4.29	0.71	2.35	0.41	0.10	0.24	0.57	1.41	0.05

GLEF Operation Plan

Because the characteristics of scale buildup in the GLEF depend heavily on the mode of operation, a test plan and schedule have been developed to obtain scaling data in order to be able to assess the technical and economic feasibility of a 50-MW demonstration plant based on the GLEF process. It contains the required tests for one-well and two-well operation in several probable operational modes, including the potential mode where brine

modification becomes necessary. This plan is tentative and may change to accommodate new information and constraints imposed by ERDA and/or the San Diego Gas & Electric Company.

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4.3 LLL Field Test Station

High-salinity geothermal fluids at high temperature and pressure are chemically complex and not easily duplicated in the laboratory. Since a major objective of the LLL Geothermal Energy Development Program is the development of brine-tolerant conversion systems for use at the Salton Sea Geothermal Field, a suitable field test station was needed for evaluating brine chemistry and materials-related problems such as scaling and cor-

rosion. Design philosophies for a field test station were dictated by the necessity of producing a multipurpose mobile test bed, easily reconfigured to test various components of a complete energy-conversion system. Mobility was desirable to maintain the option of testing more than one geothermal source. Provisions were also required for sampling, analysis, and characterization of fluids produced during experiments.

4.3.1 DESIGN AND OPERATION

An operating facility was brought on line at the Magmamax No. 1 well site in late June 1976. A simplified flow diagram for the test bed is shown in Fig. 4-18. Two-phase (vapor-liquid) well fluid is admitted to a high-efficiency separator at a rate controlled by a steam-flow control valve located near

the steam exhaust vent. Liquid level in the separator is maintained automatically by a feedback control loop. A typical experimental configuration is shown in Fig. 4-19. Three independent stations are available for receiving pure brine or pure steam, or any desired mixture of brine and steam, with provi-

Fig. 4-18. Simplified schematic diagram of the geothermal test bed.

sions for the injection of chemical additives to test brine-chemistry modification schemes for the control of scale and solids formation and the corrosion of materials at any desired pH.

Sufficient fluid must be withdrawn from the well to maintain flow. For the current source, Magmamax No. 1, this amounts to a minimum flow rate of 24,000 lb/hr. Since this is more than is required by the experiments, the excess is bypassed to the exhaust stack and injection system. The injection system consists of a flash tank and transfer pump, a 20,000-gallon holding tank, and a diesel-powered pump for transferring the brine from the holding tank to an injection well (Magmamax No. 3).

The initial experiments were configured to test scale and solids control in turbine components: nozzles expanding pure brine from wellhead conditions (215°C , 300 psig) to 100°C and 15 psig into static wear blades mounted within atmospheric pressure chambers that simulated turbine cases (Fig. 4-20). Main brine and steam lines were fabricated from plain carbon steel in accordance with ASME codes. Experimental stations were designed to facilitate reconfiguration for different runs.

The LLL field test station consists of three trailers:

1. A flat-bed type that carries the three experimental stations and the plumbing for well fluid.
2. A control and machine-shop trailer that contains the system control instrumentation and a small work area.
3. A chemistry-laboratory trailer that contains analytical instrumentation.

The placement of these trailers and ground-mounted peripheral equipment is shown in Fig. 4-21.

The actual construction of the field test station entailed a number of nontechnical and quasitechnical considerations in addition to the basic engineering design. Not the least of these was the acquisition of land, the provision of process water and electric power, and the various indemnities and agreements pertaining to the use of a suitable geothermal source under the control of a second party. In these respects, the cooperation of the San Diego Gas & Electric Company and the Magma Power Company (leaseholders and developers) was invaluable.

Fig. 4-19. Schematic of brine-modification test system.

Fig. 4-20. Scale, erosion, and stress-corrosion test configuration. The test specimen shown in the upper left fits in the elbow (simulated turbine chamber).

Fig. 4-21. Physical location of major utilities of the LLL field test station. Key: A, Magmamax No. 1 well; B, chemistry laboratory trailer; C, treated-water storage; D, 10-in. line to SDG&E; E, water supply pond; F, office trailer; G, control trailer; H, experimental trailer; I, spent-brine surge tank; J, injection pump.

4.3.2 FIELD EXPERIENCE AND RESULTS

Experimental runs have normally been 20 hr in duration, this period being adequate to provide a substantial (30%) closure of a 1/4-in. nozzle throat by scale when operating on untreated brine and to deposit up to several mils of scale on test blades. It appears that 100 hr is the maximum continuous operating period in any case, due to scale formation in level-control valves. Preliminary results indicate that scaling and suspended solids production can be controlled if separated brine is acidified, while still

at wellhead temperature and pressure, with sufficient hydrochloric acid to lower the pH of the expanded brine (100°C, 15 psig) to 4.5 or less (see Sections 4.4 and 4.5). Acid consumption rates are summarized in Fig. 4-22. These data were derived from volumetric measurements of acid injection and brine flow rates. The steep slope of the titration curve over the pH interval between 4.5 and 2.5 complicates acid injection and control systems for maintaining constant pH. Long-term *in situ*

measurements of electrochemical corrosion potentials, pH, oxidation-reduction potential, and susceptibilities of materials to droplet-induced erosion are possible when scaling and solids precipitation from expanded brine are inhibited. Improved acid-metering pumps as well as chemical methods for pH control will be evaluated in the future.

Future activities will be directed toward the following:

1. Scale and solids control at higher steam qualities at the nozzle inlet (10% mass fraction vapor) to simulate operation under total flow conditions.
2. Scale and solids control under subatmospheric expansion conditions (3 to 4 in. Hg absolute).
3. *In situ* electrochemical corrosion tests at high temperature and pressure.
4. Testing of oxidizing agents and threshold inhibitors for scale control.
5. Evaluation of scale control and corrosion in flashed-steam system components with acidified brine. A schematic of the flashed-steam assembly that will be installed and tested by mid-1977 is shown in Fig. 4-23. The results of these tests will be used as a basis for deciding whether GLEF brine acidification is feasible.
6. Scale control in titanium heat exchangers exposed to separated and acidified brine.
7. Screening of materials for service in either unmodified or chemically modified brine.

Fig. 4-22. Acid-consumption measurements for pH control (separated Magmamax No. 1 brine).

4.3.3 FACILITY ALTERATIONS

In addition to the basic test program outlined in the preceding section, it is planned to make some modifications to the LLL field test station in order to increase both its versatility and ease of operation. These modifications include the following:

1. Reducing the nozzle exhaust pressure to 3 to 4 in. Hg absolute (to simulate turbine chamber pressure) by adding pumps and an ejector to the receiver.
2. Upgrading the accuracy and convenience of the chemical feed system.

3. Adding the capability to perform stepwise pressure reduction to intermediate pressures.

4. Improving the quality of facility instrumentation and control systems.

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Fig. 4-23. Schematic of flashed-steam device that will be used to evaluate scale control and corrosion with acidified brine.

4.4 Scale-Control Tests

Brine-modification experiments carried out during the summer and fall of 1976 at the Salton Sea Geothermal Field confirmed that siliceous scale formation is a pH-dependent process. Previous work had indicated that the acidification of high-salinity geothermal brine at wellhead temperature and pressure might effectively block scaling pathways. The rationale for scale control was based on the premise that acidification reduces rates of silica polymerization and gelling (processes promoted by the formation of iron and other multivalent-ion ad-

sorption complexes on surfaces of colloidal silica) and also reduces sulfide activity products.

Scaling of simulated turbine components was inhibited when separated brine from the Magmamax No. 1 well (nominal conditions: 200 to 230°C; 220 to 320 psig; pH 5.4 to 5.8) was acidified with sufficient hydrochloric acid to reduce the pH of expanded brine (100°C) to values between 1.5 and 5.0. Acidification also significantly reduced the formation of suspended solids in low-temperature (<100°C) brine effluents (Section 4.5).

4.4.1 EXPERIMENTAL DETAILS

Scaling of turbine components was investigated by flowing single-phase brine (liquid), produced by a steam separator operated at wellhead conditions, into mixed-phase converging-diverging nozzles

with high-velocity exhaust jets directed at inline static wear blades. The brine was expanded to atmospheric pressure and low temperature (<100°C). Nozzle and wear-blade assemblies of

Ti-6Al-4V alloy were mounted in 90° elbows of low-carbon steel that simulated turbine chamber walls and also provided means for obtaining liquid samples of expanded brine effluents for pH monitoring, chemical analysis, and characterization of suspended solids (see Fig. 4-20).

Three experimental stations were run simultaneously, but at least one was always operated as a control, flowing unmodified brine. Acidification was accomplished by injecting a 2 to 6 N solution of reagent-grade hydrochloric acid. The acid was mixed with brine in shrouded 304 stainless steel tubes, about 100 cm long, upstream of the nozzles. Initially, the pH of brine effluents was measured after cooling to 30°C. It was later found that *in situ* measurements at 100°C (1 atm) were reliable, provided that brine pH was ≤ 4.5 . At higher pH, electrodes scaled rapidly and became inoperable.

A summary of the operational parameters (i.e., temperature, pressure, and pH) for each brine-

modification experiment is provided in Table 4-6. Differences between separator and nozzle temperatures and pressures reflect gauge errors ($\pm 5\%$) and are not significant. Fluctuations in average pH are reported as one standard deviation and represent departures induced by system perturbations; they do not represent measurement precision. The precision of pH measurements was $\pm 4\%$ or better, as indicated by data obtained for the control station operated with unmodified brine. Deviations from average pH values observed during acidification experiments were caused by a combination of two factors: (1) failure of commercial metering pumps used for acid injection and (2) pH excursions near an inflection point for the brine-carbonate buffered system. For instance, it was not possible to maintain a pH of 3 because this value fell on the steep part of the titration curve for the buffered system (see Fig. 4-22). Planned changes in the acid injection and pH-monitoring systems will permit significantly improved pH control.

4.4.2 SCALING BY UNMODIFIED BRINE

Chemical data for brines produced from the Magmamax No. 1 well are summarized in Section 4.5. In general, total dissolved solids varied from 17 to 18 wt% in pure brine produced by the separator to 22 to 23 wt% in expanded brine effluents. Nominal scaling rates were established for nozzles, wear blades, and elbows exposed to raw brine, so that effects of brine modification could be determined. The possibility that acid injected during an acidification experiment might have a small but significant effect as a brine diluent was also investigated. During initial experiments, water, in amounts proportional to acid requirements necess-

ary to lower brine pH to a value of 2, was injected into brine and scaling characteristics noted; scale deposition was unaffected.

Nozzles

Scale formation in nozzles is a consequence of evaporative concentration induced by steep temperature and pressure gradients. Calculated temperature and quality profiles for 8:1 expansion ratio nozzles are shown in Fig. 4-24. With increasing input quality the gradients become even steeper than

Table 4-6. Summary of operating parameters in brine-modification experiments

Experiment	Duration (hr)	Average station pH				Nozzle inlet conditions	
		1	2	3	4	Temperature (°C)	Pressure (psig)
1	20.00	5.7	5.7	—	6.0	224	240
2	22.30	1.5 ± 0.3	5.8 ± 0.1	5.7 ± 0.2	6.3 ± 0.1	200	235
3	19.83	2.2 ± 0.7	2.4 ± 1.0	5.6 ± 0.2	6.0 ± 0.1	220	263
4	18.00	3.9 ± 1.2	3.6 ± 1.3	5.5 ± 0.1	5.7 ± 0.1	221	261
5	25.75	4.2 ± 0.5	5.0 ± 0.6	5.6 ± 0.1	5.7 ± 0.1	230	319
6	20.00	3.2 ± 1.0	3.1 ± 1.0	5.4 ± 0.1	5.5 ± 0.1	225	275

those shown. Although the curves indicate a smooth transition to atmospheric pressure, hydrodynamic conditions in the nozzle exhaust region are complex, and an abrupt discontinuity in temperature and quality gradients probably occurs within that area. Nozzle scaling is a particularly insidious problem because slight changes in geometry can catastrophically reduce performance efficiencies.

A typical scaling profile for Ti-6Al-4V alloy nozzles after an average exposure of 20 hr is shown in Fig. 4-25. Maximum scale deposition was observed at the throat region of the nozzles (up to 600 μm) and in their stainless steel inlet tubes ($\sim 145 \mu\text{m}$) (Fig. 4-26). Letter designations in Fig. 4-25 are keyed to optical micrographs of scale deposited at the same points (Figs. 4-27 through 4-32). Scale adherence to the metal substrate was promoted

Fig. 4-24. Estimated temperature and quality profiles for an 8:1 expansion ratio nozzle. Input conditions (isentropic calculation): 325 psia, 218°C, 0.5% steam quality. The letter designations are keyed to optical micrographs of scale deposited at the same points (Figs. 4-27 through 4-32).

Fig. 4-25. Scaling profile in Ti-6Al-4V nozzle after 21 hr of operation. Brine inlet into nozzle was separated (unmodified) brine. The letter designations are keyed to optical micrographs of scale deposited at the same points (Figs. 4-27 through 4-32).

by thin basal layers of fine-grained, iron-rich amorphous silica. The primary heavy-metal sulfides were PbS , CuFeS_2 , ZnS , and Cu_2S . The metallic silver content of the scale increases downstream of the throat region and reaches a maximum value of about 1 wt% adjacent to the nozzle exhausts. Sulfide morphologies are indicative of diffusion-controlled growth, as discussed in Section 4.2.

Wear Blades

Static wear blades, fabricated from Ti-6Al-4V alloy, were coated with scale after exposure to high-velocity, low-temperature ($< 100^\circ\text{C}$) brine streams for average periods of 20 hr. However, scale thickness across blade surfaces was not uniform. Maximum scale accumulation occurred at the blade centers adjacent to their leading edges ($< 70 \mu\text{m}$), with thicknesses decreasing toward the peripheral regions (Fig. 4-33). The scales consisted of Cu_2S , metallic silver, and PbS in an iron-rich amorphous silica matrix. No evidence of blade erosion or corrosion was observed (see Section 4.8.3).

Epoxy

White phase is CuFeS_2

1 mm = $3.75 \mu\text{m}$

Iron-rich amorphous silica

Epoxy

Iron-rich amorphous silica

Epoxy

Iron-rich amorphous silica

Stainless steel

Fig. 4-26. Scale deposits in mixing tubes, upstream of nozzles, carrying high-temperature ($>200^\circ\text{C}$), low-quality brine from the steam separator.

Light phase is PbS

Epoxy

1 mm = $8 \mu\text{m}$

Flow

Light phase is CuFeS_2 ;
matrix is iron-rich
amorphous silica

Epoxy

Fig. 4-27. Optical micrograph of scale in region A (Figs. 4-24 and 4-25). Basal scale layer is sulfide deficient. Sulfide assembly changes from CuFeS_2 to $\text{PbS} + \text{CuFeS}_2$ in response to changing pressure regions in nozzles.

Fig. 4-28. Optical micrograph of scale in region B (Figs. 4-24 and 4-25). Scale adhesion is promoted by the deposition of sulfide-deficient iron-rich amorphous silica (1 mm = 8.78 μ m).

Fig. 4-29. Optical micrograph of scale deposited in Ti-6Al-4V alloy nozzle in region between B and C (Figs. 4-24 and 4-25). The scale consists of PbS (white) and minor quantities of Cu_2S in a matrix of fine-grained, iron-rich amorphous silica (1 mm = 6.25 μ m). The brownish phase at the top is epoxy; the light phase at the bottom is the metal.

Fig. 4-30. Scale from section C (Figs. 4-24 and 4-25), consisting mostly of PbS with some Cu_2S and minor quantities of native silver in an iron-rich amorphous silica matrix.

Fig. 4-31. Scale in sections D and E (Figs. 4-24 and 4-25) is sulfide-deficient iron-rich amorphous silica. The transition from sulfide-bearing to sulfide-deficient scale is shown at the right (section D). The sulfide assemblage is the same as for section C.

Fig. 4-32. Scale from section F (Figs. 4-24 and 4-25), consisting mostly of PbS with some native silver in an iron-rich amorphous silica matrix.

90° Elbows

The potential for scale deposition in a turbine chamber flushed with low-temperature ($<100^\circ\text{C}$) expanded brine effluents was simulated in 4-in.-diameter carbon-steel (type 1018) 90° elbows.

Deposits varied from 0.9 to 0.22 mm after average operational periods of 20 hr at pH values between 5.0 and 5.8. Scale compositions were similar to those observed on wear blades, with the exception that galena (PbS) was more abundant in the elbows.

Fig. 4-33. Typical thickness pattern of scale deposited on Ti-6Al-4V wear blades after 20-hr exposure to expanded high-salinity geothermal brine.

4.4.3 BRINE-MODIFICATION EXPERIMENTS

Scale deposition in acid-brine mixing tubes, nozzles, wear blades, and 90° elbows was either eliminated or significantly reduced when brine was acidified to pH values of 5 or less.

Mixing Tubes

Acid and brine were mixed upstream of the nozzles in horizontal stainless steel tubes. These tubes were left in place for up to 80 hr and then replaced. A comparison of scaling characteristics of tubes carrying acidified and unmodified brine is shown in Fig. 4-34. Up to 0.2 mm of chalcopyrite-bearing iron-rich amorphous silica was found in the tube carrying raw brine. However, when brine was acidified, scaling was eliminated over all but the first 2 in. of the tube. We concluded from this observation that acid-brine mixing was complete slightly downstream of the point of acid injection.

Nozzles

Two polymeric nozzles, fabricated from Teflon PFA, were exposed to brine for 20-hr periods (Fig. 4-35). One unit was operated with modified brine at pH 3.0, while the other was operated as a control with unmodified brine. The nozzle exposed to unmodified brine (pH 5.6) was coated over its entire length with a scale layer a few tenths of a millimeter thick. Scale deposition from acidified brine was

completely eliminated. Weight loss in the nozzle exposed to acidified brine was negligible, and no obvious signs of erosion were observed.

Similar results were obtained when nozzles made of Ti-6Al-4V alloy were exposed to acidified brine (Fig. 4-36). When exposed to unmodified brine (pH 5.5 to 5.8), nozzles showed scaling over their entire lengths, yet only a slight reduction in brine pH (to 5.0) was necessary to significantly reduce scale deposition. After several acidification runs over the pH interval from 1.5 to 5.0, we concluded that the scaling of metallic nozzles is controllable. However, thin layers of scale (few hundredths of a millimeter thick) were observed to form in nozzle exhaust regions in every case.

Initially, it was felt that exhaust-region scales resulted from the evaporation of brine films that crept back into the nozzles from the faceplates, a phenomenon that had been reported during laboratory tests of nozzles in the clean-water test facility at LLL. To test this possibility, a nozzle was fitted with a Teflon PFA faceplate and run in acidified brine for 36 hr. It was thought that the Teflon would not wet, and hence brine films could not penetrate to the nozzle interior. We observed, however, that although the Teflon insert remained clean, the nozzle exhaust region was scaled as before.

It was finally concluded, after discussions with members of the Turbine Design Group, that the metal nozzles, having excellent thermal conductivity characteristics, were hotter at their exhaust

Fig. 4-34. Scaling characteristics of acid-brine mixing tubes.

Fig. 4-35. Scaling characteristics of Teflon PFA nozzles after 20-hr exposure at pH 3.0 and pH 5.6.

than was the brine in contact with them. Hence brine was simply evaporating at the boundary layer. Similar scales did not form in PFA nozzles because of the much lower thermal conductivity of polymeric materials. This problem can be solved by either using composite (metallic-polymeric) nozzles or perhaps by cooling nozzle exhaust regions. The latter possibility will be tested in the field.

Wear Blades

Figures 4-37, 4-38, and 4-39 illustrate the effects of acidification on scale adhesion and accumulation on Ti-6Al-4V alloy wear blades. Scaling was controlled at pH values of 4.0 or less. The peripheral areas of blades exposed to brine at pH values of 3 or more are scaled. This deposition occurred outside the primary impingement area of the expanded brine stream and represents evaporation of thin films in the splashback zone. At pH values of 3 or less, scaling in the splashback zones is also eliminated. The composition of scale deposits in splashback zones was similar to that of deposits formed from unmodified brine, with the exception that paratacamite $[\text{Cu}_2(\text{OH})_3\text{Cl}]$ was commonly ob-

Fig. 4-36. Scaling in nozzles of Ti-6Al-4V at three different pH values for an exposure of 20 hr. Significant reduction in scaling is obtained at pH 5.0, and very little occurs at pH 1.5.

served after acidification runs. Since in an operational turbine all exposed blade surface area will be swept by brine, we concluded that blade scaling is controllable at pH values of 4.0 or lower.

Elbows

Scale deposition in turbines can be serious because of the close tolerances required between blades and housing. We found that maximum scale accumulation can be limited to 0.5 in./yr when brine is acidified to pH 4.5 or lower. At pH values below about 3.0, scale accumulation becomes negligible. However, scaling rates of between 2.4 and 3.8 in./yr were observed after exposure to unmodified brine. These results are summarized in Fig. 4-40.

Fig. 4-37. Scale accumulation on a Ti-6Al-4V wear blade exposed to expanded unmodified brine (pH 5.7) for 20 hr (separated brine at nozzle inlet). Scale thickness varies as indicated in Fig. 4-33. The flow direction is from bottom to top; the leading edge is at the bottom.

4.4.4 SUMMARY AND CONCLUSIONS

During the summer of 1976, a field test station, located at the GLEF test site in the southwestern part of the Salton Sea Geothermal Field, was used to test acidification for scale control. Experimental results indicated that scaling could be prevented in simulated turbine components when separated brine was acidified with hydrochloric acid to pH values below 5.0 while still at high temperature and pressure. Rates of suspended-solids formation were also reduced in expanded brine effluents cooled to

85°C (at atmospheric pressure). Results indicated that concentrations of suspended solids could be reduced from about 500 ppm to less than 20 ppm when brine was acidified to pH values of 4.6 or less (see Section 4.6.3). The initial brine-modification experiments used pure brine, produced by a steam separator that isolated the vapor and liquid fractions that formed as brine flowed from the geothermal reservoir, up the wellbore, and to the surface. Subsequent work will involve remixing of

Fig. 4-38. Scale accumulation on Ti-6Al-4V wear blade exposed to pH 3.1 brine for 20 hr (separated brine at nozzle inlet).

Fig. 4-39. Scale formation on Ti-6Al-4V wear blade was entirely eliminated at pH 2.3 and lower (separated brine at nozzle inlet).

Fig. 4-40. Scale deposition in a simulated turbine chamber.

acidified-brine and vapor fractions before introduction to the nozzle to evaluate scale control and acid consumption under total flow inlet conditions.

The cost of hydrochloric acid required for acidification is discussed in Section 4.5.2. Briefly, hydrochloric acid cost, derived from direct measurements of hydrochloric acid consumption for separated brine, would add about 1.1 mills/kWh, or about 6%, to the cost of energy at the bus bar. For total flow inlet to the nozzle the cost would be greater. As discussed in Section 4.5.2, the most conservative estimate possible at present leads to 1.7 mills/kWh, or about 9% of the cost of energy at the bus bar. Direct measurements of acid requirements for total flow are now in progress.

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4.5 Brine Chemistry and Suspended Solids

4.5.1 CHEMISTRY OF GEOTHERMAL BRINES AT THE GLEF SITE

Wellhead samples of brine from Magmamax No. 1, No. 2, and No. 3 wells showed considerable differences in chemical composition (Table 4-7). Clay minerals (smectite) and barium sulfate were found in solids recovered from both injection wells. As noted earlier, these constituents are probably artifacts of the past history of the wells, as neither was flowed extensively after completion. Barite is probably a result of reaction between barium in the brine and sulfate in injected irrigation water. The smectite probably represents a hydrothermal altera-

tion product of bentonitic drilling muds or injected solids. These contaminants undoubtedly seriously biased measured concentrations of silicon, barium, and possibly other brine constituents. Values shown in Table 4-7 are for wellhead samples, uncorrected for flashing; steam qualities were estimated to be about 10%.

The chemical composition of samples taken with a traversing probe from a vertical section of pipe at the wellhead of Magmamax No. 1 indicated that compositional variations caused by stratification or

Table 4-7. Composition of wellhead geothermal brine samples from Magmamax No. 1, No. 2, and No. 3 wells*

	Injection		Production, Magmamax 1
	Magmamax 3	Magmamax 2	
Date taken	3/31/76	3/18/76	8/10/76
Temperature (°C)	175	195	215
Pressure (psig)	~ 200	~ 200	235
Composition (ppm by weight):			
Lithium	134	192	141
Sodium		53,600	42,000
Silicon	101	410	202
Potassium		16,600	8,600
Iron		1,910	256
Copper		8	1
Rubidium	64	98	64
Barium	189	258	118
Boron	21	4	
Magnesium		148	80
Zinc			361
Strontium			388
Aluminum			< 1
Fluorine	149	22	
Chlorine	103,000	142,000	121,000
Calcium		27,200	20,000
Manganese	64	1,290	690
Lead		102	78
NH ₃	—	—	30–60
CO ₂	—	—	1–2 (wt%)
H ₂ S	—	—	10–30
pH			5.2
Oxidation–reduction potential (mV vs H ₂)			237
Density (g/cm ³)	1.13	1.19	1.15
Total solids (g/kg brine) by evaporation	178	244	208

* With the exception of noncondensable gases, concentrations have not been corrected for flashing. Estimated steam quality is 10%.

other inhomogeneities in flow were negligible, provided that the samples were taken during a period of constant, continuous flow. A comparison of results for these wellhead samples with those for a sample taken from the brine outlet of the LLL field test unit separator, operating at wellhead conditions, indicated that the wellhead samples were rich in the liquid phase of the brine. Results for the composition of these samples are biased about 10% high, depending on the actual steam quality of the brine. In order to obtain reliable and reproducible results for elemental compositions it is necessary to

analyze both liquid- and vapor-phase samples from a separator. The steam quality must also be determined by measuring the mass fractions of liquid and vapor. Then the composition of the whole brine can be accurately calculated.

A change of about 16% was observed in the total solids content of four brine samples taken from the LLL separator over a 6-week period of intermittent operation (Table 4-8). The reason for the change in the composition of the separated brine could not be determined with certainty because both the temperature and the flow rate at the wellhead changed

between samples. A more accurate evaluation of the time-dependent changes in brine composition will require an accurate measurement of the liquid / vapor mass ratio exhausted from the separator. This work is now in progress.

All noncondensable-gas samples were taken in stainless steel vacuum bottles filled to line pressure. The results of mass-spectrometry analyses for these samples are shown in Table 4-9. These results indicate that the noncondensable gases from each well are primarily carbon dioxide. The main difference is in the hydrogen content. Gas from the Magmamax No. 2 well is considerably richer (4.7%) in hydrogen than gas from the Magmamax No. 1 well (<0.05%).

The carbon dioxide content of samples taken from the LLL separator operating at Magmamax No. 1 wellhead conditions averaged about 135 g

CO₂/kg steam. Carbon dioxide concentrations in the whole brine were recalculated to an average value of 1.35 wt% based on an estimated steam quality of 10%.

Results for total carbonate content of separated Magmamax No. 1 brine (~125 ppm at 215°C and 242 psi) indicated that most of the carbon dioxide is flashed off with the steam in the separator, the bicarbonate ion being the primary dissolved carbonate acid-consuming species in the brine. The amount of acid required to acidify Magmamax No. 1 brine to a given pH was determined by room-temperature titrations. Brine samples from the separator were cooled by passage through a stainless steel condenser and collected in plastic bottles. The addition of 101 mg of anhydrous hydrochloric acid per kilogram of brine (101 ppm) was required to acidify the brine to a pH of 4.0. The carbon dioxide

Table 4-8. Changes in brine composition during production of Magmamax No. 1*

	Date taken			
	6/29/76	6/30/76	8/8/76	8/10/76
Temperature (°C)	200	214	230	215
Pressure (psig)	225	240	320	235
Composition (ppm by weight):				
Lithium			128	135
Sodium	40,900	42,100	41,200	42,700
Silicon	181	187	190	200
Potassium	6,900	7,000	6,600	6,500
Iron	202	161	199	180
Copper	1	1	1	1
Barium	54	85	115	118
Magnesium	125	125	95	99
Zinc	188	183	275	285
Strontium			360	373
Tin	23	23		
Aluminum				<1
Chlorine	101,000	105,000	111,000	112,000
Calcium	17,400	16,900	17,900	18,200
Manganese	502	494	565	570
Antimony	4	4		
Lead	22	22	60	59
pH		5.7	5.8	6.1
Oxidation-reduction potential (mV vs H ₂)			192	177
Density (g/cm ³)	1.12	1.12	1.13	1.14
Total solids (g/kg brine) by evaporation	169	171	197	196

* Steam quality 10%. Concentrations have not been corrected for flashing. Brine samples were obtained from the LLL separator.

Table 4-9. Noncondensable-gas composition of Magmamax brines by mass-spectrometry analyses

Sample	Date	Temp. (°C)	Pressure (psig)	Composition (vol%)					
				CO ₂	H ₂	N ₂	CH ₄	C ₂ H ₆	O ₂
Magmamax No. 2, wellhead	3/18/76	195		94	4.7	0.32	0.83	0.08	—
	3/18/76	195		93	4.7	0.4	1.1	<0.03	—
Magmamax No. 1:									
	LLL separator	6/29/76	225	96	<0.05	0.73	1.0	<0.03	0.2
	LLL separator	6/30/76	240	97	<0.05	0.2	0.5	<0.03	<0.02
	GLEF first-stage separator ^a	5/27/76	110	98	0.34	0.25	1.4	<0.03	0.03
	GLEF exhaust stack ^a	6/16/76	15	98	0.13	0.3	1.0	<0.03	0.03

^a Samples taken at the San Diego Gas & Electric Company's Geothermal Loop Experimental Facility (GLEF).

equivalent is 122 mg/kg brine and is in good agreement with analytical results for total carbonate in separated brine (125 ppm).

The concentration of dissolved hydrogen sulfide in unflashed Magmamax No. 1 brine was ≤ 30 ppm (by weight). The concentration of total sulfide in separated brine is 1 ppm; most of the hydrogen

sulfide is fractionated into the vapor phase when the brine is flashed. During several months of intermittent operation, hydrogen sulfide concentrations in noncondensable gases from Magmamax No. 1 ranged between 1500 and 2800 ppm by volume, which implies that hydrogen sulfide levels in the whole brine are not constant.

4.5.2 ACID REQUIREMENTS AND COSTS FOR pH CONTROL

In Fig. 4-41 the direct volumetric measurements of the quantity of hydrochloric acid necessary for pH reduction (see Section 4.3.2) are compared to estimates made on the basis of room-temperature titrations. The difference between the curves derived from direct measurements made at temperature on separated brine and the room-temperature titrations is due to temperature effects. The difference between the two curves is minimal near the inflection point, however, and both curves indicate a requirement of ~ 120 ppm of hydrochloric acid for pH reduction.

Direct measurements of acid consumption have not yet been made for total flow inlet to a nozzle. Titration of a wellhead sample (see Fig. 4-41), however, leads to an estimate of 180 ppm HCl, or 50% more than that required for separated brine. The additional acid requirement for the wellhead sample is believed to be due to ammonia and carbon dioxide from the noncondensable gases redissolving to form ammonium carbonate as the sample is cooled.

Fig. 4-41. HCl requirements and costs of reducing the pH of separated Magmamax No. 1 brine.

The data in Fig. 4-41 indicate that the hydrochloric acid costs for pH reduction are about 1.1 and 1.7 mills/100 lb brine for separated brine and for total flow, respectively. If one assumes a water rate of 100 lb of brine per kilowatt-hour (a high estimate for most conversion systems for HT/HS geothermal brines), the hydrochloric acid costs add 1.1 and 1.7 mills/kWh to the energy cost for a plant

in which condensate is not injected (NH_3 removal) and a plant in which the total flow is ultimately injected, respectively. The latter case applies to a total flow plant as well as more conventional plants in which condensate streams are recombined with the brine flow (e.g., the ERDA/San Diego Gas & Electric Company's hybrid flashed-steam/binary cycle system).

4.5.3 SUSPENDED-SOLIDS SAMPLING AND CHARACTERIZATION

When high-salinity brine from the Salton Sea Geothermal Field is cooled, sparingly soluble constituents precipitate. Most of these solids remain in suspension as brine flows through energy-conversion equipment. Unfortunately, process equipment handling high-velocity brine and solids can be rapidly and severely damaged by erosion.

In addition, injection of low-temperature brine effluents (the only environmentally acceptable means of brine disposal) with suspended solids could cause plugging of well casings and destruction of formation porosity, thereby shortening the useful lifetime of injection wells. It is therefore necessary to characterize suspended solids so that potential problem areas can be evaluated and control techniques formulated and tested.

Sample Descriptions

Two wells, Magmamax No. 2 and Magmamax No. 3, have been designated as injection wells for brine effluents from the Geothermal Loop Experimental Facility (GLEF) of the San Diego Gas & Electric Company. Hot brine is supplied to the facility by the Magmamax No. 1 and Woolsey No. 1 wells. Both injection wells have been flowed and sampled in order to establish a baseline so that the effects of subsequent injection could be evaluated.

Suspended solids were filtered from cooled ($<100^\circ\text{C}$) brine effluents produced by both injection wells. Sludge produced during the initial stages of Magmamax No. 3 operation was also obtained for analysis. A sampling apparatus for filtering solids from flowing brine at temperatures and pressures of up to 300°C and 600 psi was subsequently fabricated and tested. Suspended solids were recovered with this device at the Magmamax No. 1 wellhead, from single-phase brine produced by the steam separator in the LLL field test station and from the GLEF injection line. Most of the solids

were retained on a $10\text{-}\mu\text{m}$ filter. A scale sample from the downstream flange of the GLEF injection pump was also obtained for a comparative study (see Section 4.2). All samples were analyzed for their chemical and mineralogical composition and particle size distribution.

Solids Characterization

As noted previously, suspended solids found in samples of brine recovered from the injection wells were mixtures of barite (BaSO_4) and iron-rich amorphous silica, with smaller amounts of heavy-metal sulfides. Barite was probably formed by reaction between barium in the brine and sulfate in irrigation water pumped into the wells prior to extended shut-in intervals. This problem could be eliminated by pretreating irrigation water to remove the sulfate ion. A smectite sludge was recovered from the initial flow output from Magmamax No. 3. Elemental analyses indicated that the smectite clay was probably also present as a trace constituent in Magmamax No. 2 solids. These clays most likely represent hydrothermal alteration products of bentonitic drilling muds or previously injected solids.

Particle-size analysis with the scanning electron microscope indicated that 15% of the particles were in the 0.2- to $2.0\text{-}\mu\text{m}$ size range, with the remainder in the 2.0- to $20\text{-}\mu\text{m}$ range (Fig. 4-42). However, when suspensions were filtered, almost all of the particles were retained by a $10\text{-}\mu\text{m}$ filter. The bridging of filter pores by the larger particles probably accounts for the high collection efficiency.

Samples of solids recovered from high-temperature ($<200^\circ\text{C}$) brine at the Magmamax No. 1 wellhead consisted primarily of cubo-octahedral crystallites of galena (PbS), 135 to 373 nm in diameter (Fig. 4-43).

Fig. 4-42. Scanning electron micrographs of solids recovered from injection wells. Top: smectite recovered as sludge from Magmamax No. 3; center and bottom: barite recovered from Magmamax No. 2. The magnifications shown are the electron-microscope magnifications.

Samples of solids recovered from the GLEF injection line were composed primarily of iron-rich colloidal silica with a gellike structure (Fig. 4-44). Individual particles ranged from 40 to 160 nm in diameter. These particles were cemented at points of contact and had a high tendency to aggregate. Small amounts of heavy-metal sulfides (primarily PbS and ZnS) were also present in samples taken from the bottom of horizontal pipe sections, indicating that solids were stratified according to density. Elemental analyses shown in Table 4-10 indicate that calcium, iron, and manganese carbonates were also present as minor constituents.

Scale samples from the downstream flange of the GLEF injection pump were analyzed for comparison with suspended solids. This material consisted mostly of 56- to 80-nm iron-rich colloidal silica with interbedded layers of calcium and iron- and manganese-rich carbonates (Fig. 4-9). The carbonates most probably deposited when high-pH (9 to 10) condensate was remixed with flashed brine prior to injection.

Concentration of Suspended Solids in Brine Effluents

For constant flow conditions and brine chemistry, the production rate, size distribution, and composition of suspended solids is primarily dependent on temperature, pH, and pressure. Residence times are also important because an induction period is necessary for the nucleation and growth of particulates. Thus the quantity of suspended solids produced from a given brine depends to some extent on operating conditions.

The average concentration of suspended solids recovered from high-temperature ($<200^{\circ}\text{C}$) brine, produced by a steam separator operating at wellhead conditions, was less than 30 ppm. These solids consisted exclusively of submicron crystallites of PbS. Low-temperature ($<100^{\circ}\text{C}$) brine effluents, after passage through the GLEF, contained about 480 ppm suspended solids. These solids were mostly iron-rich amorphous silica, with minor quantities of heavy-metal sulfides (primarily PbS and ZnS). Calcium, iron, and manganese carbonates precipitate from brine that has been chemically modified by the addition of high-pH and carbon-rich condensate. For a 10-MW power plant utilizing brine at a rate of 8×10^5 lb/hr, the injection of suspended solids (silica plus sulfides) will be 9200 lb/day.

Fig. 4-43. Scanning electron micrographs of solids recovered from high-temperature ($>200^{\circ}\text{C}$) brine at the Magma-max No. 1 wellhead. Solids consist primarily of cubo-octahedral crystallites of galena (PbS), 135 to 373 nm in diameter. The magnifications shown are the electron-microscope magnifications.

Fig. 4-44. Transmission electron micrographs of iron-rich silica solids recovered from the GLEF injection line. Silica is in the form of colloidal particles aggregated into a gel-type structure. Individual particles have a structure identical with that observed for silica in high-temperature scales (see Section 4.2).

Table 4-10. Semiquantitative x-ray fluorescence analysis of solids recovered from the GLEF injection line

Element	Concentration (wt%) ^a			
	MX-3-L-12 ^b		MX-3-L-14 ^c	
	65 μm ^d	10 μm ^d	65 μm ^d	10 μm ^d
Silicon	50	43	32	30
Sulfur	1.7	0.9	0.7	0.4
Calcium	10	5.4	4.4	1.9
Chromium	0.9	0.4	6.4	4.6
Manganese	3.0	4.6	4.1	3.0
Iron	28	37	48	57
Nickel	2.2	0.3	—	—
Copper	0.5	0.6	0.8	0.3
Zinc	1.6	2.1	1.2	0.8
Arsenic	0.3	0.6	0.5	0.8
Strontium	0.03	0.09	0.03	0.05
Molybdenum	0.01	0.009	0.03	0.04
Silver	0.009	0.06	0.003	0.003
Cadmium	0.003	0.006	—	—
Tin	0.01	—	0.003	0.004
Antimony	0.003	0.15	0.03	0.04
Barium	0.13	0.6	0.08	0.14
Lead	1.4	4.5	1.0	1.1

^a Normalized to 100%.

^b Taken from the GLEF injection pipeline at the Magmamax No. 3 wellhead with a traversing probe positioned 0.5-in. off the bottom of the 10-in. pipe. Brine temperature 91°C; brine pressure 150 to 300 psi.

^c Taken from the GLEF injection pipeline at the Magmamax No. 3 wellhead. The sample probe was 0.75-in. below the top of the pipe. Brine temperature 91°C; brine pressure 200 to 300 psi.

^d Filter size.

Solids Control

The time elapsed before solids will plug an injection well depends largely on the porosity and on the fracturing that exists in the formation. However, there can be little doubt that plugging will even-

tually occur. Methods must therefore be developed to either prevent the formation of solids in process brine or to remove solids from the spent brine. Recent brine-modification experiments indicate that the acidification of high-temperature (<200°C) brines is an effective means of suppressing solids formation, as discussed in Section 4.5.4.

4.5.4 pH DEPENDENCE OF SOLIDS PRECIPITATION

The rate of suspended-solids production in Magmamax No. 1 brine was determined as a function of pH during acidification experiments conducted in October and November 1976. In these experiments, separated high-temperature (220°C), high-pressure (250 psi) brine was acidified and expanded through nozzles to atmospheric pressure. Samples used to determine suspended solids production were taken from elbows in the exhaust system, about 16 in. downstream from the nozzles. The temperature of

the brine at the sampling point was about 95°C. All samples were transferred to a constant-temperature bath at 85°C immediately after being taken. To determine the rate of solids production, the samples were removed from the constant-temperature bath at timed intervals and immediately filtered through glass frits with a nominal pore size of 4 to 5.5 μm . The solids were then washed with distilled water, dried at 110°C, and weighed. Figure 4-45 shows samples of cool brine resulting from the ex-

Fig. 4-45. Samples of cooled brine acidified before expansion (pH 2.4 and 3.1) and not modified before expansion (pH 5.6).

Fig. 4-46. Solids filtered from acidified brine (top, pH 3.1) and unmodified brine (bottom, pH 5.6).

pansion of acidified brine (pH 2.4 and 3.1) and unmodified brine (pH 5.6). Figure 4-46 shows the solids that remained after filtration of 3 liters of acidified (pH 3.1) and unmodified brine (pH 6). These figures qualitatively illustrate the strong effect of acidification on the reduction of suspended solids.

Initial quantitative experiments were conducted over intervals of up to 24 hr with samples in the pH range from 1.6 to 5.8. Results are shown in Fig. 4-47. These data indicate that the precipitation of suspended solids from Magmamax No. 1 brine in this pH range is essentially complete in 4 hr or less. They also show that brine acidification to a pH of 4.6 greatly inhibits the production of suspended solids. The amount of solids produced at pH 4.6 is one-tenth of that produced in unmodified brine (pH 5.8). These results were confirmed by additional experiments conducted over shorter time intervals; results are shown in Fig. 4-48.

Fig. 4-47. Rate of suspended-solids production at 85°C in separated Magmamax No. 1 brine at intervals of up to 24 hr.

Fig. 4-48. Rate of suspended-solids production at 85°C in separated Magmamax No. 1 brine during a 4-hr interval.

The quantity of suspended solids produced as a function of pH in a 4-hr time interval is shown graphically in Fig. 4-49. This figure emphasizes the decrease in solids production as the brine is acidified to pH 4.6. It shows that over 400 ppm of solids precipitated from unmodified brine (pH 5.8). However, brine acidification to pH 4.6 reduced solids production to 30 ppm.

The solubility of precipitated solids in acid solutions was also investigated. In this experiment, a 5-gallon sample of brine was taken from the Magmamax No. 1 well and allowed to cool to ambient temperature. Aliquots of the brine together with its suspended solids were then treated as shown in Table 4-11. These data indicate that the unmodified brine contained 580 ppm of suspended solids. They also show that approximately one-third of the solids redissolved when the brine was acidified to concentrations as high as 1.0 M HCl plus 0.1 M HNO₃.

In conclusion, the acidification of separated Magmamax No. 1 brine to pH 4.6 inhibits the formation of suspended solids and seems to be a promising technique for the control of solids production. However, solids do not redissolve readily in hot acid solutions (1.0 M HCl and 9.1 M HNO₃). Therefore, it does not seem practical to try to remove solids from cold brine by redissolving them with acid before injection.

Fig. 4-49. Suspended-solids production in separated Magmamax No. 1 brine as a function of pH.

Table 4-11. Response of suspended solids of acid treatment^a

Treatment	Concentration (mg/kg brine)
Filtered and washed with H ₂ O	580
Acidified to pH 4.1, allowed to stand 5 hr at room temperature, filtered, and washed with H ₂ O	615
Acidified to pH 2.0, allowed to stand 5 hr at room temperature, filtered, and washed with H ₂ O	460
Acidified to pH 2.0, allowed to stand 3 hr at 90°C, filtered, and washed with H ₂ O	400
Leached 1 hr in 1 M HCl, 0.1 M HNO ₃ at 50°C, filtered, and washed with H ₂ O	390

^a All samples were taken from a 5-gal polyethylene container of separated brine from the Magmamax No. 1 well. All samples were dried at 110°C.

4.5.5 SUSPENDED-SOLIDS PRODUCTION AT GLEF

The suspended solids in the brine effluent from each stage were sampled during the noncascade mode of operation with Magmamax No. 1 as the producing well. The average concentrations based on two or more samples from each location are shown in Table 4-12. The concentration increases progressively downstream to a value of 139 ppm at the injection wellhead. Although solids analysis is incomplete, preliminary data indicate that the composition is silica, with a high and increasing iron content and decreasing lead content. However, at the injection wellhead, the suspended solids are principally silica. In a previous analysis at the injection wellhead, the suspended solids concentration was 480 ppm when operating with a combination of condensate and injected brine. At that time the solids composition was high in iron, unlike the more recent sampling. However, the iron content in the suspended solids from the separators is very high.

The difference may be a direct result of high-pH condensate recombination that precipitates an iron species (e.g., hydrated ferric oxide) or coprecipitates iron and silica.

Figure 4-50 is a plot of the total-suspended-solids data for GLEF process streams. Data on total sus-

pended silica are more meaningful but were not available at the time of this writing. The same plot shows amorphous-silica solubility data and silica concentration in the various brine streams of the GLEF process. This information suggests that supersaturation with respect to silica occurs in the third stage. Until the data on silica concentration in the suspended solids become available, it is not known whether a significant increase in silica actually occurs in the third stage.

Fig. 4-50. Suspended-solids concentration in GLEF process streams.

4.5.6 CHEMISTRY OF PROCESS STREAMS AT GLEF

Measurements of pH as a function of acid consumption were conducted on both the brine and condensate from all four stages of the GLEF. Magmamax No. 1 was the producing well, and condensate was not combined with the brine. As predicted in thermochemical calculations, progressively less

acid was required by the brine as the temperature dropped with multiple flashing. To lower the pH of the first stage requires approximately 60 ppm hydrochloric acid, well within economic limits.

The condensate, however, consumes about 10 times as much acid as the corresponding brine. This

Fig. 4-51. Brine pH reduction in all four stages of the GLEF as a function of hydrochloric acid usage. (Brine from the Magmamax No. 1 well.)

is a combined effect of the greater solubility of carbon dioxide in the condensate and the absorption of ammonia. The first-stage condensate contains 313 ppm of ammonia, and the fourth-stage condensate contains about 96 ppm.

Figures 4-51 and 4-52 show pH reduction as a function of hydrochloric acid usage for the brine and for the condensate, respectively. The slopes of the curves are characteristic of $\text{CO}_2/\text{HCO}_3^-$ and

Fig. 4-52. Condensate pH reduction as a function of hydrochloric acid usage.

NH_4OH titrations. These data are currently being analyzed to determine optimum operating modes and acidification schemes for scale control in the GLEF.

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4.6 Chemical Modeling of Geothermal Systems

A chemical modeling study was undertaken to predict scaling, gas distributions, and buffering characteristics of geothermal brines. This is necessary to provide a theoretical basis for understanding the experimental results, optimizing process control, and predicting the effects of brine chemistry changes. The work involved developing the LLL brine-chemistry computer code SOLCAL (*solubility calculator*), which performs equilibrium calculations for high-salinity, two-phase fluids over

the pH and temperature ranges encountered in their processing.

The code requires as input a brine composition, a quality-temperature function, effective activity coefficients for the ions, and equilibrium constants for the chemical reactions considered (Fig. 4-53). The composition and quality can be measured. Activity coefficients and equilibrium constants are taken from the literature and extrapolated as required to brine conditions.

4.6.1 SOLIDS PRECIPITATION AND HYDROGEN SULFIDE DISTRIBUTION

The output information is activity products for scale-forming solids, phase distributions of gases and their aqueous species, and estimates of pH and buffering capacity under varying conditions. A

typical set of activity and solubility product curves for PbS , a major scale-forming material in the Magmamax No. 1 brine, is shown in Fig. 4-54. It is evident that the reservoir pH must be low and that pre-

Fig. 4-53. Input required for the SOLCAL code for brine-chemistry calculations.

Fig. 4-54. Galena (PbS) activity and solubility product curves for Magmamax No. 1 brine.

Fig. 4-55. Distribution of hydrogen sulfide species for Magmamax No. 1 brine.

precipitation of this substance is caused primarily by pH increases during cooling. Although the SOLCAL code treats only individual precipitation reactions, it correctly predicts deposition behavior wherever crystalline solids are formed. Figure 4-55

shows the distribution of hydrogen sulfide species, an important consideration with respect to sulfide scale formation and potential corrosion problems. These examples illustrate the usefulness of the calculational capability.

4.6.2 TITRATION CALCULATION AND pH VARIATION WITH TEMPERATURE

Chemical brine modification by acidification has been found to be of value in controlling scale formation, and it is therefore of considerable importance to evaluate acid-consuming reactions. Figure 4-56 shows a computer simulation of a titration experiment, in which a liquid sample of brine is taken at any one of several high temperatures, cooled to room temperature without a change in total carbon dioxide content, and titrated with hydrochloric acid. The reaction considered was the neutralization of the bicarbonate ion, and the agreement with field measurements supports the concept that buffering and pH changes in the fluid are primarily due to conversions between carbon dioxide and aqueous carbonate species. Figure 4-57 shows a computation of brine pH, based on the assumption that it is completely determined by these carbonate reactions. The results are in reasonable agreement

with observation, although the effects of other known reactions have not yet been included. The results suggest that downwell pH may be as low as 4.5 for Magmamax No. 1 brine. Improvement in the code will be made to take into account the effects of dissolved ammonia on fluid pH. These results will be important in assessing the injection process and in selecting materials for production-well casings.

It is concluded that considerable information on geothermal fluid systems can be obtained from a relatively simple computational model. This is possible largely through careful selection of the most important reactions and close interaction with field experimentation.

D. D. Jackson

Fig. 4-56. Acid requirements for reducing the pH of separated Magmamax No. 1 brine, computed by SOLCAL.

Fig. 4-57. Computation of brine pH as a function of temperature.

4.7 Geochemical Code Calculations

The Helgeson-Herrick code has been used to predict chemical equilibria in complex, Salton Sea-type, high-salinity geothermal brine to determine its usefulness for brine problems. The code was employed to survey the effects of changing both brine pH and oxidation state for some initial brine compositions. Emphasis so far has been

focused on determining the phases that precipitate from these brines at 60, 100, 150, 200, and 250°C as a function of pH and oxidation potential; the latter is used to establish a boundary condition (i.e., either very reducing or very oxidizing). Precipitation reactions at intermediate temperatures cannot be considered, because the code does not follow

continuously cooling regimes. Furthermore, in its present form, the code cannot be used to estimate absolute amounts of precipitation, nor can it consider relative differences in chemical reaction rates.

Accurate chemical analyses were available for brine produced by the Sinclair No. 4 and Magmamax No. 1 wells. These compositions were then recalculated to nominal reservoir states by assuming appropriate wellhead qualities. An example of

output from a typical computer run is shown in Table 4-13 for the case of reducing Magmamax No. 1 brine.

In general, the number of different mineral precipitates increases significantly as temperature decreases and pH increases (Table 4-14). Siliceous scales consist of various kinds of crystalline heavy-metal sulfides dispersed within, or growing on, a fine-grained amorphous silica matrix. However,

Table 4-13. Compositions of brines from the Salton Sea Geothermal Field

Species	Sinclair No. 4 ^a			Magmamax No. 1 ^b		
	ppm	Moles/ kg fluid	Moles/ kg water	ppm	Moles/ kg fluid	Moles/ kg water
Al	2.000E + 00	7.412E - 05	9.515E - 05	1.593E + 02	5.904E - 03	7.510E - 03
Ba				7.017E + 02	5.109E - 03	6.499E - 03
B				3.358E + 02	3.106E - 02	3.951E - 02
Ca	2.250E + 04	5.614E - 01	7.206E - 01	1.982E + 04	4.945E - 01	6.290E - 01
Cl	1.300E + 05	3.667E + 00	4.707E + 00	1.049E + 05	2.959E + 00	3.764E + 00
CO ₂	4.000E + 03	9.089E - 02	1.167E - 01	2.583E + 04	5.869E - 01	7.465E - 01
Cu	3.000E + 00	4.721E - 05	6.061E + 05	1.205E + 00	1.896E - 05	2.412E - 05
F				1.722E + 02	9.064E - 03	1.153E - 02
Fe	1.150E + 03	2.059E - 02	2.643E - 02	2.411E + 02	4.317E - 03	5.491E - 03
Pb	7.800E + 01	3.765E - 04	4.833E - 04	3.444E + 01	1.662E - 04	2.114E - 04
Li				1.468E + 02	2.116E - 02	2.691E - 02
Mg	5.900E + 01	2.427E - 03	3.115E - 03	9.643E + 01	3.966E - 03	5.045E - 03
Mn	9.500E + 02	1.729E - 02	2.220E - 02	6.578E + 02	1.197E - 02	1.523E - 02
K	1.160E + 04	2.967E - 01	3.808E - 01	9.480E + 03	2.424E - 01	3.084E - 01
SiO ₂	4.213E + 02	7.012E - 03	9.001E - 03	5.123E + 02	8.526E - 03	1.085E - 02
Ag	5.000E - 01	4.635E - 06	5.950E - 06	4.305E - 01	3.991E - 06	5.076E - 06
Na	5.070E + 04	2.205E + 00	2.831E + 00	4.999E + 04	2.174E + 00	2.766E + 00
Sr				4.589E + 02	5.237E - 03	6.662E - 03
S	6.000E + 00	1.871E - 04	2.402E - 04	3.248E + 01	1.013E - 03	1.288E - 03
Zn				2.428E + 02	3.714E - 03	4.724E - 03
TDS	2.170E + 05			1.880E + 05		

^a Wellhead quality 15 wt%; pH ≤ 5.0.
^b Wellhead quality 10 wt%; pH ≤ 5.0.

Table 4-14. Calculated number of phases precipitating from Magmamax brine under reducing conditions

pH	Number of phases precipitating				
	250°C	200°C	150°C	100°C	60°C
2-3	14	24	28	31	26
3-4	37	38	42	43	37
4-5	49	50	50	49	43
5-6	66	59	60	58	47
6-8	70	71	73	72	55
8-10	61	54	59	73	60

Table 4-15. Predicted and observed sulfide precipitation from Magmamax No. 1 brine under reducing conditions

T(°C)	pH (calculated)	Sulfides	
		Predicted	Observed
250	4-5	FeE, PbS	No observation
200	4-5	FeE, PbS, ZnS, CuFeS ₂	CuFeS ₂ + PbS + ZnS + Cu ₂ S + Fe-rich amorphous silica matrix (S present); Ag content above background (218-210°C)
150	4-5	FeS, PbS, ZnS, CuFeS ₂ , FeS ₂ , Cu ₅ FeS ₄ , ZnS (hexagonal)	Sulfide mineral deficient; Fe-rich amorphous silica matrix (S present)
100	5-6	ZnS, PbS, Cu ₅ FeS ₄ , FeS, Cu ₂ S, FeS ₂ , ZnS (hexagonal), Ag ₂ S	PbS + Cu ₂ S in Fe-rich amorphous silica matrix (S present); Ag content is high (130-110°C)
60	5-6	Cu ₂ S, CuFeS ₂ , Cu ₅ FeS ₄ , ZnS, PbS, FeS ₂ , ZnS, (hexagonal), FeS, Ag ₂ S, CuS	No observation

most of the predicted phases (largely silicates) are not observed in scale, although the predicted metal ions are observed in the matrix in the form of adsorption complexes on colloidal silica.

The failure of predicted substances to appear is not surprising and can be attributed primarily to the code's inability to consider kinetic data. This shortcoming can be partially resolved by "calibrating" the code, for a given chemical system, by interacting with scale-deposition experiments. When this is done, important scaling reactions can be predicted with some confidence, and valuable insights are gained with respect to scaling processes (Table 4-15).

For instance, with lower pH, the code predicts and field observations confirm that the heavy-

metal sulfide content of siliceous scales decreases. Other calculations indicate that heavy-metal sulfides can be eliminated by raising the oxidation potential of brine, but at the risk of precipitating oxides or sulfates.

We are currently studying the feasibility of using the Helgeson-Herrick code to model brine-rock interactions that might cause chemical plugging of reservoir rocks adjacent to injection wells. Although there are many problems associated with its use, this code can be a valuable analytical tool, useful in understanding complex chemical systems.

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4.8 Turbine Materials Selection and Evaluation

In the total flow process the turbine system will be exposed to high-velocity, high-salinity brine containing entrained particulates and liquid droplets. High static stresses due to centrifugal forces will be developed in the rotating turbine wheel. These stresses are directly proportional to the density of the material, and for a titanium alloy wheel they may exceed 400 MPa (58×10^3 psi). Superimposed will be cyclic stresses arising, in part, from the cyclic impact of the exhaust from the nozzles. Critical parts requiring dimensional stability such as nozzles and turbine blades may suffer unacceptable

wear, especially due to erosion.

The Niland geothermal brines are extremely corrosive. The survival, at least of low-cost materials, in these environments is undoubtedly due to the protective nature of scale deposits. Scale deposition, however, must be eliminated from turbine components, which will likely exaggerate the corrosion problems. To address these problems, we have acquired a number of materials and are evaluating them for their resistance to erosion, corrosion, and stress-corrosion cracking (SCC).

4.8.1 SELECTION CRITERIA AND TESTING METHODS

The selection of candidate structural materials for screening, testing, and evaluation is based on a number of criteria. For critically stressed components, materials having a high strength-to-density ratio are needed. For example, using a safety factor of 2 for the turbine wheel, a minimum yield strength of 800 MPa (116×10^3 psi) is required for titanium-base alloys. With a density increase of about 1.8 times relative to titanium alloys, iron-, nickel-, and cobalt-base alloys will require a corresponding minimum yield strength of about 1440 MPa (209×10^3 psi).

The behavior of materials in other chloride-bearing environments indicates that of these alloys, the titanium-base alloys are the most likely to resist failure by stress-corrosion cracking. Nickel- and cobalt-base alloys are also promising candidates. Martensitic and ferritic iron-base alloys are likely to be susceptible to hydrogen embrittlement due to hydrogen sulfide, while austenitic iron-base alloys are likely to be susceptible to chloride stress-corrosion cracking. At the expected turbine-wheel temperatures (nozzle exhaust) of less than 100°C, resistance to general pitting and crevice corrosion in chlorides generally decreases in going from titanium-base to nickel- or cobalt-base, to iron-base alloys.

It therefore appears that the most likely candidate would be a titanium-base alloy. Since there has been extensive experience with the production and use of Ti-6Al-4V and since there is no definite evidence that some other titanium-base alloy would be superior, we have elected to consider this alloy as our prime candidate. We are examining a number of other titanium-base alloys. As other backup alloys, two cobalt-base (MP35N and Haynes 25) and two nickel-base (Hastelloy C-276 and Inconel 718) alloys are being examined.

The principal tests that are currently being used for the titanium-base alloys and the other five alloys mentioned above are for evaluation of resistance to erosion and stress-corrosion cracking. However, a number of structural alloys of lower strength than that required for the turbine wheel are also being examined for their resistance to stress-corrosion cracking.

As a backup for potential erosion problems in critical areas of the turbine, we are examining a number of materials as coatings or inserts. The coatings have been applied to the substrate test specimens by a variety of methods. To date, only

some of the acquired materials have been screened or tested for erosion and stress-corrosion cracking, and these are described below.

Erosion Tests

Erosion tests are made on wear blades with overall dimensions of $12.70 \times 44.45 \times 66.68$ mm, with a wedge-shaped leading edge tapered to have an included angle of 20° and a tip radius of 250 μ m. A nozzle and wear-blade assembly is shown in Fig. 4-58. The nozzle can either be of a monolithic type or used with a removable insert; in both cases the nozzle has an expansion ratio of 8:1. Assemblies have been used at both the LLL freshwater facility and the LLL geothermal field facility, with the blades being exposed to two-phase high-velocity nozzle exhaust fluids. The extent of wear at the leading edge is determined by the use of a shadowgraph comparator with a magnification of 10 $\times$. It is capable of detecting deviations from flatness to ± 2.5 μ m. Cross sections of both the wear blades and the nozzles are examined metallographically.

Fig. 4-58. Nozzle and wear-blade assembly.

Stress-Corrosion Cracking

Preliminary screening tests for stress-corrosion cracking were performed at LLL in simulated brine heated to approximately 100°C. The test solution was based on a Sinclair No. 4 well analysis. To a basic solution of 2.8 M NaCl-0.41 M KCl-0.37 M CaCl the following were added: 32 ppm S²⁻ (as Na₂S • 9H₂O), 1100 ppm Mn²⁺ (as MnCl₂ • 4H₂O), 1680 ppm Fe³⁺ (as FeCl₃ • 4H₂O), and 80 ppm Mg²⁺ (as MgCl₂ • 6H₂O). The S²⁻ content continually decreases by the escape of H₂S. The solution was continuously purged with argon during the exposure of titanium-base alloys or aerated on exposure of iron-, nickel-, and cobalt-base alloys.

We used 150-mm-long U-bend specimens (25-mm bend radius) for testing iron-, nickel-, and cobalt-base alloys. In an attempt to obtain information on crevice corrosion in the stressed samples, two samples of each alloy were bent together to the U-shape in a press over a 25-mm-diameter mandrel

and bolted together in place. Thus the outer sample was exposed in tension to the brine and in compression to the crevice condition, with the reverse conditions for the inner sample. Testing of the titanium-base alloys was done by four-point loading of prenotched bent-beam sheet specimens and by tensile straining of sheet specimens to failure over a wide range of strain rates.

Evidence of stress-corrosion cracking in the field environment is obtained on specimens that have been constrained in a bent-beam mode in a fixture attached to the wear blades, as shown in Fig. 4-20. Two specimens are placed on each side of the wear blade, one specimen being superimposed on the other in each set. The front (overlying) specimens receive the direct impact from the nozzle exhaust, while the rear (underlying) specimens are protected from such direct impingement. This arrangement offers the possibility of separating the effects of erosion from those of corrosion or stress-corrosion cracking in the nozzle exhaust environment.

4.8.2 RESULTS OF EROSION TESTS

LLL Freshwater Facility

Table 4-16 lists the test conditions and results obtained after the exposure of several wear blades at the LLL freshwater facility. Although the exposure periods are short, they do indicate some differences between the soft commercially pure titanium and the harder materials.

Field Exposure Tests

Some early work at the Sinclair No. 4 well showed that severe erosion was obtained on a 304 stainless steel nozzle wear blade exposed to a two-phase exhaust fluid velocity of about 488 m/sec (1600 ft/sec). Aside from such early tests, materials exposed in the field have been limited to tests that

Table 4-16. Exposure of wear blades in LLL freshwater facility

<i>Test conditions</i>		
Boiler temperature	275°C	
Boiler pressure	7.93 MPa (1150 psi)	
Nozzle inlet pressure	2.76 MPa (400 psi)	
Fluid velocity at nozzle	488 m/sec (1600 ft/sec)	
<i>Test results</i>		
Material	Exposure (hr)	Wear at blade tips
Commercial purity Ti	3.5	63 μm (0.0025 in.)
Ti-6 Al-4V carbonitrided	8.0	Nil
Sintered B ₄ C, 98% density	3.5	Nil
Sintered ZrC ₂ , 98% density	3.5	Nil

have been directed primarily to chemistry studies. Two such chemistry test series have recently been made:

1. Brine acidification for scale control.
2. Acid consumption evaluation.

Wear blades, nozzles, and SCC samples exposed in these two test series have been partially evaluated. In the first test series, seventeen Ti-6Al-4V nozzle and wear-blade assemblies were exposed for 20 hr to flowing brine (liquid-phase inlet) chemically modified to produce pH values ranging from 1.5 to 5.7 (unmodified). The brine was expanded to atmospheric pressure with a nozzle exit velocity of approximately 244 m/sec (800 ft/sec) and at a temperature of approximately 100°C.

Visual examination of all exposed nozzles and plates suggested that no erosion had taken place. The dimensions of three nozzles (pH 2.4, 3.9, 5.6) were found to be identical with the original specifications within the allowable machining tolerances of $\pm 2.5 \mu\text{m}$. The leading edges of five wear blades (pH 1.5 to 5.6) were examined with a shadowgraph comparator. A maximum deviation

from flatness along the edge of $25 \mu\text{m}$ was obtained, which is within machining tolerance. Erosion tests under conditions more representative of the operation of a total flow turbine (two-phase inlet, subatmospheric expansion) will be conducted during 1977.

In the second recent field test series, eight nozzles and wear-blade assemblies, each containing two pairs of SCC specimens, were exposed for periods ranging from 7.5 to 110 hr. As in the earlier test series, the brine was expanded to atmospheric pressure ($\sim 244\text{-m/sec}$ velocity at $\sim 100^\circ\text{C}$). Table 4-17 lists the wear blades with the test conditions. Preliminary visual observations of leading-edge erosion (see Table 4-17) were made by placing a straightedge along the tip of the blade edge and using feeler gauges. A light source indicated the presence of any wear between straightedge and blade tip. With the exception of the 2.25Cr-1Mo steel (which was added as a sample that was expected to erode) and Hastelloy C-276, erosion was not apparent. Figures 4-59 and 4-60 show wear blades of 2.25Cr-1Mo (37-hr exposure) and Ti-6Al-4V (110-hr exposure), respectively, with attached SCC specimens.

4.8.3 PRELIMINARY RESULTS ON STRESS-CORROSION CRACKING

Laboratory Tests

Table 4-18 lists the alloys that were exposed to the aerated simulated Niland brine for 6430 hr in the form of U-bend specimens. This is the first group of alloys in the iron-, nickel-, and cobalt-base series that was ready for testing; it represents only a small part of the materials in this series that are

being field tested. In fact, these alloys include only one (Haynes 25) of the high-strength materials in this category that we now have on hand. Nevertheless, the results of these tests are of value since they do show large differences in corrosion resistance between the various exposed alloys. These results will be helpful in selecting cladding or liners for piping and vessels handling acidified brine. Additional

Table 4-17. Erosion tests in chemically modified brine expanded to a velocity of $\sim 244 \text{ m/sec}$ and $\sim 100^\circ\text{C}$ at atmospheric pressure

Alloy	Condition	Exposure (hr)	Average pH	Erosion at edge (μm)
Ti-6Al-4V	α - β annealed and stress relieved	110	2.9	Nil
Ti-6Al-4V	α - β annealed and stress relieved	22.5	3.7	Nil
Ti-6Al-4V	Carbonitrided at 1000°C	59.5	4.5	Nil
Ti-0.3Mo-0.8Ni	Mill annealed	25	2.5	Nil
Hastelloy C-276	Mill annealed	37	2.9	~ 25
MP35N	Cold-rolled 50% and aged at 538°C for 4 hr	37	3.1	Nil
Haynes No. 25	Cold-rolled 25%	7.5	2.7	Nil
2.25Cr-1Mo steel	Quenched and tempered	37	2.6	~ 400

Fig. 4-59. Wear blade and SCC bent-beam specimen of Fe-0.13C-2.20Cr-0.95Mo showing erosion/corrosion after exposure for 37 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH 2.6).

Fig. 4-60. Wear blade and SCC bent-beam specimens of Ti-6Al-4V after exposure for 110 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH 2.9).

tests of these materials at temperatures of up to 200°C are planned for 1977. Examples of the two extremes of corrosion attack are shown in Fig. 4-61: Haynes 25, which was relatively unaffected, and 18Cr-2Mo-Ti stabilized, which was severely damaged.

The level of the test solution was kept at just above the curved portion of the U-bend. Damage was primarily in the form of pitting and fissures or cracks in the sample area exposed to the liquid phase (stressed portion of sample) and pitting in the sample area exposed to the vapor phase

Table 4-18. Alloys exposed in the form of U-bend specimens to aerated simulated Niland brine for 640 hr

Alloy	Constituent					Other main constituents	Crystal structure
	Cr	Ni	Mo	Mn	C		
Haynes No. 25 ^{a,b}	19.85	10.42	—	1.61	0.10	14.43 W, 2.33 Fe	fcc
Alloy 6X ^b	20.30	24.30	6.54	1.69	0.02	0.05 AP, 0.04 Nb 0.03 N	fcc
29Cr-4Mo ^b	29.40	0.11	3.95	0.02	0.005	0.06 AP, 0.014 N	bcc
316 SS ^c	17	13	2.5	—	—		fcc
Nitronic 33 ^b	17.83	3.34	—	13.87	0.046	0.29 N	fcc
304 SS ^c	18	10	0	—	—		fcc
Alloy 439 ^c	18	—	—	—	—	Ti-stabilized	bcc
26Cr-1Mo ^b	25.59	0.11	1.03	0.01	0.0010	0.0010 N	bcc
18Cr-2Mo-Ti stabilized ^c	18	—	2			Ti-stabilized	bcc

^a Cobalt base; all others are iron base.

^b Actual composition.

^c Nominal composition.

(relatively unstressed). Relatively thin, adherent oxide films or stains had formed to various degrees on all external surfaces. However, the two inner surfaces in contact with each other in each case remained mostly clean and bright, except along the edges and where pits had formed. Table 4-19 lists the relative ranking of the exposed alloys based on observations made with the stereomicroscope up to

a magnification of 32 $\times$, in order of resistance to attack. We have arbitrarily referred to pits along the inner surface as crevices, although this term may not always reflect the actual corrosion mode. In many cases, it was difficult to distinguish between "cracks" and corrosion "channels," and therefore the term "fissures" is used to include both morphologies. This question will be resolved later

Fig. 4-61. U-bend specimens (25-mm bend radius) exposed for 714 hr to aerated simulated Niland brine at 100°C. Left: Haynes 25; right: 18Cr-2Mo-Ti stabilized. Note the relatively unaffected Haynes 25, while 18Cr-2Mo-Ti stabilized is severely attacked. In both photographs the specimen at the left is the outer specimen; that at the right is the inner specimen.

Table 4-19. Relative ranking of some "corrosion-resistant" alloys exposed to aerated simulated Niland geothermal brine for 640 hr.

Alloy	Liquid-phase exposure			Vapor-phase exposure	
	Pitting	Fissures	Crevice	Pitting	Crevice
Haynes No. 25	1	1	1	1	1
Alloy 6X	2	3	3	2	1
29Cr-4Mo	3	2	2	6	5
316 SS	4	6	4	3	3
Nitronic 33	5	5	5	4	4
304 SS	6	7	9	5	9
Alloy 439	7	(a)	7	7	7
26Cr-1Mo	8	(a)	8	9	8
18Cr-2Mo-Ti stabilized	9	4	6	8	6

* Pitting obscured identification of fissures.

by more detailed metallographic examination of polished sections.

It is significant to note that, of these alloys, only Haynes 25 did not show any evidence of pitting, crevice attack, or stress-corrosion cracking. In view of the promising results previously reported for 26Cr-1Mo for geothermal environments, we were surprised at the poor performance of this material; yet our own experience with 26Cr-1Mo tubing in the field is consistent with our laboratory results, which show this alloy to be highly susceptible to corrosion in the simulated brine.

Table 4-20 lists the titanium-base alloys that were exposed as prenotched bent-beam samples in simulated Niland brine. Two sets of loading periods may be noted: 455 and 1360 hr for all alloys and 1370 and 2275 hr for the Ti-6Al-4V alloy. No evidence of any corrosion attack was detected at the end of the first period. In an attempt to induce stress-corrosion cracking, the specimens were periodically step-loaded in the test solution to produce fresh surfaces at slip offsets caused by such

deformation. With the specimens still in the test fixtures, they were examined periodically under the stereomicroscope. After the specimens were reintroduced into the brine solution, the existing notches were newly scribed each time with a diamond-tip scribe to ensure a freshly exposed surface at the root of the notch. No evidence of stress-corrosion cracking could be detected in any of the samples after the second exposure, although some very minor pitting was observed in several of these alloys.

In a further attempt to screen the titanium-base alloys for stress-corrosion cracking, a number of samples from four of the alloys were strained to failure in tension in the simulated Niland brine at 100°C over a range of strain rates. Specimens were also tested in air at 100°C at an intermediate strain rate. No evidence of stress-corrosion cracking was indicated by the measured mechanical properties (yield strength, ultimate tensile strength, elongation). Figure 4-62 shows schematically the results we obtained and those reported in the

Table 4-20. Exposure of six titanium-base alloys in simulated Niland geothermal brine at 100°C under constrained bent-beam loading conditions^a

Loading conditions at surface	Exposure (hr)	
	All alloys tested	Ti-6Al-4V only
Preloaded to 90% of yield strength	455	1370
Preloaded in excess of yield strength	455	1370
Intermittently step-loaded in solution in test cell an additional 10 to 15% strain	1360	2275

^aAlloys tested: Ti-8Al-1Mo-1V, Ti-6Al-4V, Ti-6Al-6V-2Sn, Ti-3Al-8V-6Cr-4Mo-4Zr, Ti-6Al-2Sn-2Zr-2Mo-0.25Si, Ti-5Al-5Sn-2Zr-2Mo-0.25Si.

Fig. 4-62. Schematic curves illustrating results obtained for titanium alloys in (a) simulated Niland brine, continuously argon purged at 100°C and (b) those reported in the literature showing susceptibility to stress-corrosion cracking in chlorides at 25°C. Arrows in (a) indicate strain rates.

literature for titanium-base alloys tested in what seems to have been a less aggressive environment (3 to 5% chlorides at 25°C) than ours. In Fig. 4-62b the differences between the two curves provide a measure of the alloy's susceptibility to stress-corrosion cracking. No significant differences were shown by our tests.

Field Exposure Tests

We are currently evaluating the SCC specimens that were exposed in the last series of field tests

conducted during 1976. Table 4-21 lists the alloys examined, the test conditions, and the preliminary observations. Two samples of each alloy or alloy condition were mounted in pairs as described earlier. The comments listed in this table refer only to the tensile surface of the outer samples, which were in the direct path of the nozzle exhaust. A cursory examination of the inner samples showed that erosion or pitting was usually much less for an inner sample than for the corresponding outer sample.

Figures 4-63, 4-64, and 4-65 show polished sur-

Table 4-21. Exposure of bent-beam sheet samples in nozzle exhaust of chemically modified brine^a

Alloy	Condition	Exposure (hr)	Avg. pH	Exposed sample condition
Ti-6Al-4V	α - β annealed, water quenched, and stressed relieved	110	2.9	Several cracks in notch ~ 2-3 μ m deep, one 20 μ m deep
Ti-6Al-4V	α - β annealed, air cooled, and stress relieved	110	2.9	Several cracks in notch ~ 2-3 μ m deep, one 20 μ m deep
Ti-4Al-3Mo-1V	Mill annealed	22.5	3.7	Very few pits ~ 3-7 μ m deep
Ti-6Al-4V ^a	α - β annealed, air cooled, and stress relieved	22.5	3.7	No cracks found
Ti-8Al-1Mo-1V	Duplex mill annealed	25	2.5	Many cracks ~ 25-50 μ m deep
Ti-6Al-4V	Mill annealed	25	2.5	Crack ~ 15 μ m deep at root of notch
Fe-26Cr-1Mo-(Ti)	Mill annealed	37	2.9	Some pits ~ 5-10 μ m deep Many pits ~ 15-50 μ m deep Many pits ~ 15-50 μ m deep Many pits ~ 15-50 μ m deep
304 SS	Mill annealed	37	2.9	
MP35N	40% cold-rolled and aged at 538°C for 4 hr	37	3.1	
316 SS	Mill annealed	37	3.1	
2.25Cr-1Mo steel	Quenched and tempered	37	2.6	Severe pitting corrosion/erosion
410 SS	Quenched and tempered	37	2.6	Severe pitting corrosion/erosion
4130 Mo modified	Quenched and tempered	7.5	2.7	Many pits up to 70 μ m deep
4130	Quenched and tempered	7.5	2.7	Many pits up to 75 μ m deep, several up to 230 μ m deep
Fe-18Cr-2Mo-(Ti)	Mill annealed	59.5	4.5	Some pits ~ 3-5 μ m deep
Fe-29Cr-4Mo	Mill annealed	59.5	4.5	Some cracks ~ 10-15 μ m deep

^a Extra low interstitials.

faces of several of the specimens listed in Table 4-21. A 25-mm length of the center portion of each specimen was mounted so that the large-dimension surface (notched tensile surface) would be perpendicular to the viewing surface (thickness surface).

It is clear that the Ti-6Al-4V alloy shows the best resistance to pitting, erosion, and general corrosion. Very little difference was seen between 25- and 110-hr exposures. Although cracks in this alloy did form at the notch, it must be kept in mind that all these specimens were loaded appreciably above yield. (Specimens were loaded directly into the test fixtures with a jig so that no springback would be obtained.) It is encouraging to note that no cracks

were found in the extra-low-interstitial (ELI) grade of the Ti-6Al-4V alloy. This is consistent with the known greater resistance of the ELI grade to environmental stress cracking. The Ti-8Al-1Mo-1V alloy, which is known to be susceptible to stress-corrosion cracking in chlorides, was added as a control sample, and indeed it showed cracks along the whole length of the surface; the cracks were oriented perpendicular to the tensile stresses (Fig. 4-65). We observed extensive pitting along the surface of the outer sample for alloy MP35N (Fig. 4-64). The relatively unaffected surface of the inner sample suggests that this "pitting" is primarily the result of erosion.

Figure 4-66 shows the surface for molybdenum-

Fig. 4-63. Crack initiation in prenotched region in a Ti-6Al-4V specimen after exposure for 110 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH ~ 2.9). No evidence of erosion. Large crack (~ 20 - μm deep) at root of notch has opened up. Specimen in as-polished condition. Views (a) and (b) at notch; (c) at region remote from notch.

Fig. 4-64. Significant erosion (or corrosion-assisted erosion) and possibly some crack initiation in an MP35N specimen after exposure for 37 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH ~ 3.1). Specimen is in as-polished condition. Views (a) and (b) at notch; (c) at region remote from notch.

modified 4130 steel (0.75 Mo + 0.035Nb), in which pitting is primarily due to corrosion, although certainly assisted by erosion. Numerous fingerlike intrusions of the corrosion product into the metal can be seen. The surface of the inner sample (not shown) was only slightly less degraded. It is clear that the low-alloy iron-base materials such as the 4130 steel and 2.25Cr-1Mo cannot be used even for containment purposes if exposed to the direct impact of the nozzle exhaust.

It is of interest to point out that the elbows used for holding the nozzle and wear-blade assembly

suffered excessive erosion/corrosion at effluent splash points around the wear blades. One of these elbows became perforated. The elbows were made from 4130 and 1018 steels.

It is likely that some differences in the degradation of the SCC specimens can be attributed to environmental differences that at present we cannot identify. For example, referring to Table 4-21, the Fe-26Cr-1Mo-Ti stabilized and 304 stainless steel SCC samples suffered noticeably less degradation than did the MP35N and 316 stainless steel samples. The first two were exposed together on the

Fig. 4-65. Erosion and stress-corrosion cracking in a Ti-8Al-1Mo-1V specimen after exposure for 25 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH ~ 2.5). Note that cracks apparently do not always initiate at a notch. Specimen is in the as-polished condition. Views (a) and (c) at notch; (b) and (d) at region remote from notch.

same wear blade as were the last two but in a different station (elbow). Both sets were exposed during the same period (37 hr). We would have expected the MP35N to be superior to the Fe-26Cr-1Mo-Ti stabilized alloy and the 316 stainless steel to be superior to the 304 stainless steel, but the reverse trend was observed. These and other questions will be addressed in completing the analyses of the SCC samples and wear blades exposed in these last two field test series.

To date, the Ti-6Al-4V alloy appears to have the

Fig. 4-66. Extensive erosion and corrosion (note corrosion product) in a molybdenum-modified 4130 steel (0.75 Mo + 0.035 Nb) after exposure for only 7.5 hr to the nozzle exhaust of chemically modified liquid brine nozzle inlet expanded to atmospheric pressure (~ 244 m/sec, $\sim 100^\circ\text{C}$, pH ~ 2.7). Specimen in as-polished condition, prenotched. Note the relatively unattacked "protected" compressive surface in view (a). (Specimen supplied by R. F. Hehemann, Case Western Reserve University.)

best combination of resistance to erosion in the Niland geothermal nozzle exhaust effluent at 100°C . In future tests, we plan on exposing additional samples of this alloy (and other titanium alloys with $\leq 6\%$ Al content) in various heat-treated conditions, as well as several high-strength iron-, nickel-, and cobalt-base alloys both as wear blades and as SCC samples.

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4.9 Plant Materials Selection and Evaluation

A plant materials selection and evaluation program has been initiated with the objective of identifying candidate materials for the brine-handling portion of geothermal power plants utilizing the HT/HS brines of the Salton Sea Geothermal Field. The emphasis will be on materials for use with brines acidified to prevent scaling and solids-precipitation problems. Both low-cost materials (e.g., low-alloy steels) and more expensive materials suitable for use as cladding or liners for

carbon-steel components and for small components such as valves are considered. The early emphasis is on using the relatively rapid electrochemical corrosion measurement methods to establish the effect of pH on corrosion rates, to study the protection afforded by scale, and to screen materials for corrosion resistance in low-pH brines. These early results are described in this section. Plans for 1977 include direct corrosion tests on candidate materials.

4.9.1 ELECTROCHEMICAL CORROSION TESTS

A program is presently under way in which electrochemical measurement techniques (Fig. 4-67) are being used to study the corrosion behavior of various materials in high-salinity geothermal brine and to provide additional characterization of

the brine itself. The specific objectives of this investigation are the following:

1. To determine the feasibility of the linear polarization-resistance technique for measuring

Fig. 4-67. System for measurement of corrosion parameters and brine characteristics.

general corrosion rates of materials in actual geothermal brine.

2. To use the linear polarization-resistance technique to rapidly compare the corrosion rates of alloys that are candidates for plant structural materials.

3. To ascertain the effects of prescaling on corrosion rates.

4. To determine the feasibility of the on-line measurement of brine pH, brine oxidation-reduction potential, and the corrosion potentials of the test materials.

Measurements of pH and oxidation-reduction potential at the LLL field test station provide experience for handling the problems that may be encountered when these parameters are monitored in more advanced facilities. Measurements of corrosion potentials yield information for predicting pitting- and galvanic-corrosion phenomena.

The initial field tests reported here were conducted in flowing single-phase brine at atmospheric pressure and approximately 100°C. The test brine

was obtained from the nozzle-exhaust effluent of the LLL field test station, which was operated with brine from the Magmamax No. 1 well. Under the existing conditions of steam separation, the test brine had a relatively low concentration of total sulfide.

Figure 4-67 is a schematic diagram of the apparatus and instrumentation used to measure the corrosion and brine parameters. The test cell, through which the brine flowed continuously, was fabricated from polycarbonate plastic. Corrosion rates were measured by means of a Petrolite Instruments Company corrosion-rate meter and probe assemblies with interchangeable electrodes. The electrodes are fabricated from the test materials. The oxidation-reduction and corrosion potentials of the corroding specimens were measured against the saturated calomel electrode (SCE) by means of a digital voltmeter. The components shown in Fig. 4-67 were required to operate in the field and in the cell at temperatures of up to 100°C. Multiple-cell assemblies and a switching circuit made possible the simultaneous testing of several materials.

4.9.2 EFFECT OF pH AND SCALING ON CORROSION RATES

Several corrosion-rate test runs were made in which the specimen material was first exposed to unmodified brine (pH 5.5) and then to acidified brine. Figure 4-68 shows the corrosion rate of mild steel when the brine remained acidified throughout the run (curve A) compared to the behavior observed when the material was first exposed to unmodified brine (curve B). The rapid initial decrease in corrosion rate in the latter case, compared to the relatively constant value in the acidified brine (curve A), is probably partly caused by the accumulation of corrosion product but is believed to be due mainly to the protective nature of the silica scale formed at pH 5.5 in this separated brine.

The specimens of curves A and B were both preheated before exposure to the brine. Curve C shows the effect of not preheating the material. As can be seen, the scale formed on the specimen that was not preheated was significantly more protective. Electron-microprobe analysis confirmed that a silica-rich scale formed on both specimens exposed to unmodified brine.

As illustrated in Fig. 4-68, when the scaled specimens were exposed to acidified brine without interrupting the run, there was a rapid rise in corrosion rate, revealing that the scale is not "perfectly" protective. However, the corrosion rate again decreased with time more rapidly than did the rate for unscaled material. It is known that the silica scale is porous, and it is possible that in acidified brine the scale does not dissolve and the pores fill with corrosion product, thus causing the rapid decrease in corrosion rate.

In any event, though the data are only preliminary, it appears that a significant degree of protection against general corrosion in acidified brine can be afforded by first exposing material to the low-temperature unmodified brine. This result suggests that it may be possible to protect the GLEF from corrosion in acidified brine by prescaling. A test of this will be made using the small-scale flashed-steam assembly shown schematically in Fig. 4-23.

Fig. 4-68. Effect of effluent-brine pH on the corrosion rates of mild steel.

4.9.3 EFFECT OF ALLOY COMPOSITION ON CORROSION RATES

The corrosion resistances of several commercial steels containing chromium and/or molybdenum, a cobalt-base alloy, and a titanium-base alloy were evaluated in acidified brine at 90 to 100°C. Corrosion rates were measured by the linear polarization-resistance technique. The test specimens were preheated with water to ~70°C before introduction of the effluent brine into the test cell. The velocity of the brine in the test cell was maintained at ~6 cm/sec.

The alloys tested, their nominal chemical compositions, and heat treatments are listed in Tables 4-22 and 4-23. In addition to the chromium-molybdenum steels, which are under consideration as low-cost plant materials for downstream compo-

nents of the total flow impulse-turbine system (turbine case, piping, etc.), more highly alloyed, and hence costlier, materials were also subjected to a determination of corrosion rates. Some of these materials are under consideration for turbine construction and as cladding or liners for steel components. These materials and their characterizations are also listed in Tables 4-22 and 4-23. After the appropriate heat treatment, each test specimen was polished with silicon carbide papers (240-, 400-, and 600-grit), ultrasonically cleaned in a detergent solution for 30 min, and then carefully handled during assembly of the test probe.

Results of the corrosion-rate tests of the chromium-molybdenum alloys are summarized in

Table 4-22. Low- to moderate-cost materials (iron-based) tested for corrosion resistance in geothermal brine

Alloy (commercial name)	Composition (wt %)				Heat treatment(s)
	Cr	Mo	C	Others	
Ingot iron			0.08		As received
AISI 1018 steel			0.18	0.70 Mn, 0.20 Si	As received
Soo-90	0.95	0.20	0.30	0.50 Mn, 0.30 Si	As received
A-204 Grade B		0.53	0.23	0.45 Mn, 0.26 Si	Quenched: 1700°F for 1 hr, water quenched; quenched and tempered: 1700°F for 1 hr, followed by 1175°F for 2 hr, water quenched
A-387 Grade 12	0.89	0.47	0.14	0.45 Mn, 0.20 Si	Same
A-387 Grade 64	2.20	0.95	0.13	0.44 Mn, 0.15 Si	Same
5Cr-0.5Mo	5.58	0.54	0.084		Same
AISI 410 SS	12.27		0.075	0.26 Ni	Quenched: 1800°F for 1 hr, water quenched; quenched and tempered: 1175°F for 2 hr, water quenched

Table 4-23. Expensive materials tested for corrosion resistance in geothermal brine

Alloy	Composition	Heat treatment
AISI 304 SS	Fe base + 19 Cr, 10 Ni	1900°F for 1 hr, water quenched
18Cr-2Mo stabilized	Fe base + 18 Cr, 2 Mo, 0.48 (Nb + Ti)	1500°F for 1 hr, water quenched
Haynes 25	Co base + 20 Cr, 10 Ni, 14 W, 3 Fe	1100°F for 5 hr, air cooled
Ti-6Al-4V	Ti base + 6 Al, 4 V	As received (mill annealed)

Fig. 4-69. The corrosion rate is the integrated average of the corrosion rate measured as a function of time during the test period of 8 to 15 hr. Chromium improves the resistance of steel to general corrosion because a more protective oxide, Cr_2O_3 , forms. The Cr_2O_3 is thermodynamically stable in the pH range of 2 to 5, which is the range of interest for brine acidification to prevent scaling. Molybdenum, as an alloy additive to steel, improves the resistance to pitting and crevice corrosion in chloride environments.

Figure 4-69 indicates that additions of chromium and molybdenum significantly lower the corrosion rates in geothermal brine. However, the data are scattered, and this variation may be due to the differences in heat treatments, lack of good pH control, and other experimental nonreproducibility.

Although all of the chromium-molybdenum steels were tested in both the as-quenched and the quenched-and-tempered conditions, no definite correlation between corrosion rate and heat treatment was noted. Generally, the quenched-and-tempered condition is preferred because of more desirable mechanical properties. The pH ranged between 2 and 4.5 for each test, but the manner in which the pH excursion occurred may have influenced subsequent corrosion rates. As noted previously, steps are being taken to improve pH control.

Figure 4-69 also indicates the cost of chromium and molybdenum additions relative to carbon steel (unity). It appears that the use of chromium-molybdenum steels with sufficient corrosion resistance in low pH, low-temperature en-

vironments would increase the cost of materials by a factor of between 2 and 3.

Another possible upper limit to the amount of alloy addition is the change in corrosion morphology from general corrosion (metal wastage) to localized corrosion (pitting and crevice attack). Localized corrosion is unpredictable and cannot be incorporated into design considerations. Examination of AISI 410 stainless steel exposed to acidified brine revealed significant pitting attack, although the overall corrosion rate was low. The linear polarization-resistance technique is valid only for determining general corrosion rates. Pitting was most severe for the quenched-and-tempered condition but was observed for the as-quenched condition as well. One other alloy, Fe-18Cr-2Mo-Ti stabilized, showed microscopic pitting, but no pitting was detected on any other alloy (10 $\times$ magnification). As expected, Haynes 25, AISI 304 stainless steel, and Ti-6Al-4V had very low corrosion rates (less than 2 mils/yr).

Susceptibility to pitting corrosion decreases as the chromium, and especially the molybdenum, content of the stainless steel increases. Thus, below 12% alloy addition, general corrosion occurs and the rate decreases with an increase in alloy addition. Above 12% alloy addition, pitting corrosion occurs, and this form of attack may continue to perhaps about 30% Cr + Mo. Alloys containing more than 30% Cr + Mo may be immune to pitting attack.

4.9.4 MEASUREMENTS OF OXIDATION-REDUCTION POTENTIAL AND pH

The oxidation-reduction potential of the brine during the corrosion test runs varied slowly in the range of +0.10 to +0.34 V versus the normal hydrogen electrode, with the mean value being about +0.20 V. This is in good agreement with values of +0.15 and +0.20 V found previously for cooled wellhead brine. This oxidation-reduction potential is believed to be determined primarily by the Fe(II)/Fe(III) equilibrium, with Fe(II) predominating in these solutions.

In the measurement of pH with a glass electrode, there was agreement within ± 0.2 pH unit between

Fig. 4-69. Effect of alloy composition on corrosion rate. (Decrease in the relative price of steel with 10% alloying element reflects the high production of AISI type 410 stainless steel.)

the on-line measurements at 100°C and off-line measurements at 30°C with a different apparatus. It was found that both the pH and oxidation-reduction potential measurements were reliable for at least 100 hr of exposure as long as the pH of the brine was less than 4.6. Above that value, scaling soon rendered the electrodes inoperative. In an operating plant, good control of pH at lower values, short exposure times, or periodic cleaning of the electrodes will be required. Because there is less scaling, a higher temperature of exposure would also be beneficial.

4.9.5 POLYMERIC MATERIALS

Since the 1975 field tests, work has continued in the laboratory in three areas: continued screening of materials for brine resistance at 300, 250, and 106°C, examination of exposed surfaces with the

help of contact-angle and roughness measurements, and the preparation of both coated and homogeneous specimens for forthcoming field tests.

Continuation of the 300°C static brine tests for almost 1400 hr in some cases has shown that the better materials, once stabilized after 50 to 100 hr, remain unaffected for the long term. In screening tests in boiling brine at ambient pressure, many materials that failed at higher temperatures are stable, which should give designers more options in selecting materials for downstream plant use.

In the 106°C tests, contact-angle measurements and roughness determinations are being made before and after the test in an attempt to detect the onset and character of incipient changes. It is hoped that chemical erosion (roughness), surface chemical reaction (e.g., hydrolysis), and deposition of foreign species (scaling) can be separately identified.

In the field tests there are some 10 different locations where polymeric materials will be or are being exposed to brine. More than 280 samples (including replicates) have been prepared by a variety of methods or otherwise obtained for testing. A brief summary of the kinds of tests to be (or being) done follows, starting at the well or inlet end of a plant.

1. Pipes lined with Teflon TFE and Teflon PFA are ready to be installed between well and nozzle.

2. A sample-bearing rod supported lengthwise in the center of a pipe will allow exposure to unexpanded high-temperature brine flow. This arrangement will allow 15 samples to be tested at once. Machined homogeneous and coated panels are ready. Polymer-concrete samples from Brookhaven will be exposed here also.

3. Test nozzles have been made from materials that performed best in the 1975 field exposures (Havig H-Resin/C-composite, Ryton PPS/glass, Teflon PFA, and carbon). These nozzles have the more desirable 8:1 expansion ratio instead of the earlier 2:1 ratio and a smaller throat diameter. Two of the Teflon PFA nozzles have been used during the brine-acidification tests. After 20 hr the first had gained only 10 mg (essentially no scaling), and the throat had increased only 11 mils in diameter;

whether this was due to resin flow, nozzle expansion to fill the holder, or erosion could not be determined. The second nozzle run in unmodified brine scaled, as did titanium nozzles coated with a Teflon FEP-based primer only and with Fluorad FC-721, a fluorinated polymethacrylate.

4. Wear blades have been given coatings of potential value as anti-scalants. In an initial test a 0.05- μ m coating of Fluorad FC-721 developed a thin coating of scale. Thicker, conventional fluorocarbon coatings have been applied to other blades for test.

5. Coated steel panels are attached immediately behind the wear blades for test, simulating turbine or turbine chamber surfaces. Nine panels coated with six materials have been tested for up to 37 hr. Panels coated with Ryton/Teflon TFE and Teflon FEP were the cleanest, having from none to a very thin partial cover of almost transparent scale.

6. Sealants will be tested in this same "post-wear-blade" position in the form of lap-shear specimens. Before-test and after-test tensile values will be compared.

7. Steel pipe elbows carrying the expanded brine from the nozzle area have been lined with Ryton PPS and with Teflon FEP and tested on stream for 40 hr. Approximately 90% of the Ryton PPS became partially or completely detached, but only about 15% of the Teflon FEP coating was missing, where the most erosive part of the stream had impacted. Little or no scaling was in evidence. The manufacturer of Ryton PPS has developed a much improved method of bonding this coating to steel, which will be tried.

8. Teflon TFE sleeves are used to protect pipe and direct the brine flow from the steel elbows to a collection tank. Some scale collects on sleeve surfaces but remains loose and is readily knocked off.

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4.10 Failure Analysis of Components

The analysis of failures caused by corrosion and erosion, and the steps required to prevent additional failures are important tasks for successful operations at both the GLEF and the field test station. Of importance also is that the information to

be gained in analyzing these failures will contribute greatly to the bank of information that we are accumulating from the screening and testing of potential candidate materials in geothermal environments.

4.10.1 GEOTHERMAL LOOP EXPERIMENTAL FACILITY

Elbow and Valve Failures

Several components from the GLEF were extensively eroded and/or corroded and in some cases perforated through the walls. These consist of two elbows 152 mm (6 in.) in diameter, one 254- to 152-mm (10- to 6-in.) reducing elbow, and a control valve. The failures can be attributed largely to flashing of the brine causing precipitation of particulates and formation of droplets. Preliminary visual examination of these components suggests that erosion is the primary cause of the failures: gouges or striations running parallel to the flow direction are seen. However, deep localized pits are also present, which indicates that corrosion is an important contributing factor. The entrained droplets may contain high concentrations of carbon dioxide or hydrogen sulfide and become entrapped at incipient pits; with buildup of acidic conditions, pitting becomes self-perpetuating and is accelerated at such points. Erosive action from particulates will further contribute to the acceleration.

Figure 4-70 shows the valve body on the downstream side of the valve and the connecting flange upstream from the first-stage separator at the GLEF. Excessive wear is readily apparent. Figure 4-71 shows erosion striations in an elbow that had been perforated and repaired by welding. Unfortunately, proper analysis of this elbow is difficult because of the presence of the filler metal. The

Fig. 4-70. Erosion in downstream end of valve body of control valve and connecting flange (152 mm diameter) upstream from the first-stage separator at the GLEF.

analysis of the remaining two (unrepaired) elbows and a more detailed evaluation of the valve body are pending. These parts consist of plain carbon structural steels. The replacement valve, which also failed, is presently being repaired with Stellite 6B hard-facing material.

Failure of Downhole Pressure-Sensing Tubing

Pressure-sensing tubing used for the surveillance of downwell pressure changes during the reinjection of brine effluents had failed while in use at Magmamax well No. 3. The tubing (2.44-mm o.d., 0.76-mm wall) was fabricated from Fe-26Cr-1Mo. After being submerged for some 30 days with some 50 hr of intermittent flow, the tubing failed and separated at the 396-m-depth level in the well. Since nearly 6000 m of this tubing was on hand ready for such use, it was imperative that the source of this failure be established and any necessary remedial action taken. A final report is in preparation. A brief review of this report and of additional findings is given below.

Figure 4-72 shows low-magnification views of Fe-26Cr-1Mo cut from the tubing at the 396-m-depth failure. Note the presence of numerous deep pits on the specimen immediately adjacent to the

Fig. 4-71. Erosion of elbow connected downstream to control valve for first-stage separator at the GLEF.

Fig. 4-72. Low-magnification views of Fe-26Cr-1Mo specimens. (a) Cut 1-m length tubing section taken adjacent to failure at 396-m well depth; specimen cracked on first bend 10 cm from failure in well. Note numerous deep corrosion pits. (b) Specimen 50 cm from failure in well shows relatively ductile behavior on bending. Note absence of any deep pits as seen in (a).

failure (Fig. 4-72a). The specimen easily cracked when bent as shown. By contrast, the specimen taken approximately 50 cm from the failure point was relatively ductile and showed little pitting (Fig. 4-72b). Figure 4-73 shows polished cross sections of the tubing immediately adjacent to the failure; pits are present only on a portion of the surface extending longitudinally along the tubing. Figure 4-74 shows some of the details of an etched section. Several features can be seen here: heavy decoration of the grain boundary by precipitates, a cold-worked structure, and a sawtooth-like attack. The precipitation suggests that the material may be in a sensitized condition; the cold-worked structure may be indicative of a lack of ductility; the sawtooth attack is suggestive of being on the bor-

derline (on a voltage-current density polarization curve) of stress-corrosion cracking. Evidence of stress-corrosion cracking in the form of cracks and branching was absent. The absence of any intergranular attack is surprising in view of the grain-boundary precipitates.

It is important that the content of carbon and of nitrogen be kept to low maximum values and that the alloy be rapidly cooled through the sensitization-temperature ranges; otherwise excessive precipitation of chromium-rich carbides and nitrides will occur. We therefore contacted the tubing manufacturer and the supplier of the alloy to determine whether proper precautions were taken to prevent contamination by carbon or nitrogen during the processing of this material. Samples of the

Fig. 4-73. Polished sections from fractured end of Fe-26Cr-1Mo tubing that failed at the 396-m well depth: (a) longitudinal section; (b) transverse section. Note pits are present along only a portion of the surface parallel to the axis of the tubing.

(a)

150 μm

(b)

30 μm

Fig. 4-74. Longitudinal section of Fe-26Cr-1Mo tubing exposed at the 209-m well depth level. Specimen taken from portion of tubing that failed during rewinding on removal from the well. Electrolytic etch in 40% HNO₃-60% H₂O. Note transgranular sawtooth-like attack and heavy grain-boundary precipitation in (b).

failed tubing as well as of the unexposed tubing were analyzed for carbon and nitrogen by us and by the alloy supplier. The results indicated that the alloy was not contaminated during processing and that the problem could have been due to faulty temperature control during final heat treatment. Since corrective action had to be taken immediately to allow the use of some 300 m of this tubing, we heat-treated some unexposed tubing according to recommendations provided by the alloy supplier; this tubing was then put in service. After an exposure of only several weeks, this heat-treated tubing also failed.

A piece of the original unexposed tubing was sent to the alloy supplier, who heat-treated a section of it using the procedure recommended to us. The original and heat-treated conditions were evaluated; the results are listed in Table 4-24. The ingot analysis is given as 10 ppm carbon, 50 ppm oxygen, and 115 ppm nitrogen. The specifications for carbon and nitrogen are 100 and 150 ppm maximum, respectively; that for oxygen is not given. The supplier claims that no detrimental effects should be obtained below 200 ppm nitrogen. The values we obtained are 20 ppm carbon and 140 ppm nitrogen prior to annealing and 30 ppm carbon and 140 ppm nitrogen after annealing, well within the allowable limits.

As a replacement material, we are recommending the use of Hastelloy C-276, which can be produced in continuous coiled lengths of small-sized tubing. Other possibilities are MP35N, Fe-29Cr-4Mo, and several titanium-base alloys.

Sampling Coil

Some concern existed as to possible failure of a 304 stainless steel spiral-wound, water-cooled sampling coil. The coil had been used 100 hr for sampling brine at both the GLEF and the LLL field test station. Examination of sections of the tubing showed areas of corrosion and crack initiation. Figure 4-75 shows an area along the inside diameter that includes both a stress-corrosion crack and a pit; the latter is possibly due to a combination of erosion and corrosion. Substitute materials (Inconel 625, tantalum, etc.) are being obtained for the new sampling coil.

Table 4-24. Results reported by supplier for samples of Fe-26Cr-1Mo pressure-sensing tubing used by the San Diego Gas & Electric Company.

Test	Original sample	Annealed sample
Streicher corrosion rate test	0.00557	0.00139
Weld hardness, R_B	99.6	93.4
Base metal hardness, R_B	98.9	85.4
Tensile strength, ksi	94.0	62.0
0.2% offset yield strength, ksi	75.7	47.0
Elongation, %	2.7	<22.5
Carbon content, ppm	6.0	—
Oxygen content, ppm	202.0	—
Nitrogen content, ppm	131	—

Fig. 4-75. Area along the inside diameter of 304 stainless steel tubing, showing stress-corrosion cracking and pitting. The tubing was used as a sampling coil for about 100 hr of exposure to flowing brine.

4.10.2 LLL FIELD TEST STATION

Acid-Mixing Tube Failure

A shrouded 304 stainless steel tube (6.35-mm o.d., 0.9-mm wall) that served as the remix line in a field experiment failed after 3 hr of exposure. The experiment involved injecting the previously separated vapor component into the flowing acidified brine (230°C). The failure occurred about 50 cm upstream from the point of vapor injection, just downstream from the point of acid injection; therefore the failure cannot be related to the presence of the vapor-phase constituents, but rather to the acidification.

Figure 4-76 shows a longitudinal section near the failure in which cracks can be seen propagating away from the inner surface of the tubing. Cracking is predominantly transgranular. Pitting corrosion is also present. Evidence of crack branching can be seen in Fig. 4-76b, which is a high-magnification view of one of the large cracks shown in Fig. 4-76a. The crack morphology is typical of chloride stress-corrosion cracking. Decoration of the grain boundaries with precipitates indicates that the material is in a sensitized state; however, it is unlikely that this

Fig. 4-76. Longitudinal section adjacent to failure of 304 stainless steel remixing tube. Note several stress-corrosion cracks in view (a), one of which is shown at an enlarged magnification in view (b). Note pitting (P) on surface and branching (B) of a primary crack.

Fig. 4-77. As-polished sample of carbon-steel pipe, showing perforating pit in surface. Note continuous corrosion layer and small pits on surface. Key: A, pipe wall; B, shallow pit; C, continuous corrosion layer; D, patch-plate welded perforation; E, scale deposit; F, sample mount; G, mount material; H, metal sulfides.

contributed significantly to the cracking. Why this particular tubing failed and not any of the others is as yet unknown. The failure illustrates the lack of reliability of austenitic stainless steels even in short-term use. Such alloys as Hastelloy C-276, zirconium, and Inconel 600 are preferred choices for the containment of high-temperature acidified brine.

Surface-Pipeline and Well-Casing Failures*

The surface pipeline, which served to transfer brine from the Sinclair No. 4 well to the former site of the LLL field testing laboratory, and casing from this well had been perforated by pitting corrosion. The pipeline had been repaired many times by welding patch plates over the perforations. Several meters of corroded surface pipe and about 30 cm of corroded casing were received by us for evaluation. The chemical analysis of the two materials is listed in Table 4-25.

Figure 4-77 shows a composite of a polished section through one of the pits that had perforated the wall of the surface pipe; the perforation had subsequently been patched. Metallographic examination of some 20 samples showed several such perforating pits and that the inside surface of the pipe was covered with a continuous adherent layer of corro-

sion product with numerous shallow pits. Examples of such pits can be seen in Figs. 4-77 and 4-78. The corrosion product, in turn, is covered with a deposit of silica-rich scale containing heavy-metal

Fig. 4-78. General corrosion and pitting in surface, carbon-steel pipe. View (a) shows continuous surface corrosion product layer with initial stages of pitting (a). View (b) shows bowl-shaped pit in same specimen as in view (a). Note cracked scale deposit (B). View (a) etched; view (b) as polished.

*From a paper presented by A. Goldberg and L. Owen at the Electrochemical Society Meeting, Las Vegas, Nevada, October 1976.

Table 4-25. Chemical analysis of corroded surface-pipe and wellhead-casing materials

Material	Composition (wt%)								
	C	Mn	P	S	Si	Cr	Ni	Mo	Cu
Surface pipe	0.02	0.87	0.020	0.016	0.15	0.05	0.02	0.03	0.10
Wellhead casing	0.43	1.12	0.005	0.025	0.02	0.09	0.01	0.04	0.05

sulfides. Analysis of the corrosion product showed that it consisted almost entirely of magnetite (Fe_3O_4). A transition region was present between the scale deposit and the corrosion product, with fluctuations in the iron and silica contents; the iron content generally decreased and the silicon content correspondingly increased on traversing from the corrosion product to the scale. An example of such a transition region is shown in Fig. 4-79. This region could have formed as a result of interaction between the scale and corrosion product or through

the dissolution of corrosion product and its subsequent coprecipitation with the scale.

A common feature of the metal-corrosion product interface was the presence of numerous fingerlike intrusions or channels of corrosion product penetrating into the metal surface. Such selective attack is revealed in Figs. 4-80 (surface pipe) and 4-81 (casing). We were unsuccessful in our attempt to unequivocally relate this selective attack either to the steel alloy microconstituents (pearlite, ferrite, or carbide) or to the nonmetallic inclusions. In both pipes, areas could be selected where either pearlite or proeutectoid ferrite had apparently been selectively attacked.

The material in the pit shown in Fig. 4-77 consists primarily of scale. It is thought that when the pipe wall was breached, brine erupted throughout the opening formed by pit perforation, eroding away the original material in the pit. Following repair of the pipe, the eroded pit filled with siliceous heavy-metal sulfide scale while further corrosion of the pit walls took place. It is interesting to note that, aside from the few perforating pits, the surface pipe suffered relatively mild attack. It is not known whether the wellhead casing had a larger or smaller frequency of perforation of deep pits than did the surface pipe, but the severity of general corrosion and overall pitting corrosion was greater for the casing.

It should be noted that examinations by the San Diego Gas & Electric Company of mild steel piping used for 2 years of intermittent field tests in the same area (Niland, California) where the Sinclair No. 4 well is located revealed no severe corrosion, only general corrosion with some shallow pits. The brines in the area are relatively reducing and at a pH ranging from 5 to 6. Based on the Pourbaix diagram, both iron and Fe_2O_3 should dissolve in the brine solution. We believe that the siliceous scale deposits play an important role in inhibiting the corrosion of these plain carbon steels. However, if the scale is penetrated, then attack of the underlying metal will be accelerated, since conditions for crevice attack are present.

Fig. 4-79. Transition zone between corrosion product and scale deposit in wellhead carbon-steel casing, within a pit and along surface corrosion-product layer. As-polished specimens.

Fig. 4-80. Apparent selective attack of the surface carbon-steel pipe. Note fingerlike intrusions or channels of corrosion product penetrating into steel pipe. View (a) as polished; view (b) etched with 2% Nital.

Fig. 4-81. Apparent selective attack on the wellhead carbon-steel casing. Note very fine fingerlike intrusions or channels of corrosion product penetrating into steel pipe. View (a) as polished; view (b) etched with 2% Nital.

Unfortunately, a log of the operation of the well was not available to us. It is known, however, that operation was intermittent, and it would be expected that during such periods the brine level would drop in the well with infusion of air. In addition, on at least one occasion, the surface pipes had been flushed with irrigation water. If brine had locally penetrated the scale during periods of shut-down, the corrosion in these areas would be greatly accelerated by the presence of infiltrated oxygen. It is likely that the corrosion is cathodically controlled; the accelerated corrosion of carbon and low-alloy steels in seawater due to aeration is well established.

Without adequate knowledge of the environmental conditions, it is meaningless to propose any

detailed corrosion mechanism. However, it is reasonable to assume that corrosion of the steels occurred in the usual sequence of iron dissolution to the ferrous ion and the subsequent hydrolysis of the metal ions to ferrous hydroxide with local decrease in pH. Ferrous hydroxide, being relatively unstable, in turn converts to the magnetite that we have identified as the main constituent of the corrosion product. If the anodic dissolution reaction occurs in regions where movement of the products of the hydrolysis is restricted, conditions for pitting (or crevice corrosion) will ensue. The presence of oxygen will accentuate such conditions.

During shutdowns, thermal expansion differences between scale and metal could result in cracking of the scale during cooling. Therefore the

combination of fractured scale and oxygen addition could cause the accelerated localized attack, eventually leading to perforation of the pipe wall. These pipe failures point out the importance of maintaining a low oxygen content (low oxidation-reduction potential), especially the prevention of excessive

oxygen infusion into the plant line during periods of shutdown.

A. Goldberg
E. O. Snell

5. EARTH SCIENCES PROGRAM

5. EARTH SCIENCES PROGRAM

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5. EARTH SCIENCES PROGRAM

5.1 Introduction

Resource assessment and management plans are prerequisites to the commercial development of known geothermal resource areas in California's Imperial Valley. Fundamental questions are the sizing of the power plant and the design of arrays of production and injection wells. Specifically, for a given resource, what are the optimum well spacings and depths for desired plant capacities? This analysis obviously requires information on the subsurface distribution of movable heat and the potential flow characteristics of wells. Other matters of particular concern involve the chemical and physical properties of injected effluents, insofar as they influence subsurface porosity and permeability characteristics, and the potential for man-made local subsidence.

5.2 Geological Studies

Petrographic analysis of drill cuttings from wells in the southwestern part of the Salton Sea Geothermal Field (Fig. 5-1) has resulted in the categorization of the sedimentary sequence:

Depth (m)	Sedimentary sequence
0 to 325	Cap rock
325 to 900-1100	Hydrothermally altered reservoir rock with relatively high porosity (15-30%)
900-1100 to 4064	Hydrothermally altered reservoir rock with relatively low porosity ($\leq 15\%$)

Although laboratory measurements of core samples from two wells (Woolsey No. 1 and State of California No. 1) indicate that intergranular porosity decreases with depth, fracture porosity may contribute significantly to the total porosity of the system. The geologic picture that emerges from spontaneous-potential (SP) log correlations is that of a structural basin whose axis lies to the northwest of Magmamax Well No. 2.

The Earth Sciences effort is primarily concerned with the development of an accurate resource assessment and utilization plan in support of the eventual commercial exploitation of the Salton Sea Geothermal Field. Our immediate objectives include interpretation of the subsurface geology at the Salton Sea Geothermal Field and collecting data to improve estimates of the economically recoverable thermal energy. We are also developing simulation techniques for studying fluid and heat extraction from geothermal reservoirs, performance characteristics of production and injection wells, and the relationships between the compressibility of reservoir rocks and the potential for surface subsidence.

L. B. Owen

Terminology

Technically, there are no unaltered sediments in the cuttings that were examined. The presence of thermal springs at the surface indicates that hot brines have penetrated the entire sedimentary section, and it is reasonable to expect that they have permeated the rocks along the route to the surface whenever they have been able to do so. The brine-induced alteration effects in the uppermost reservoir rocks are principally silicification and clay-mineral reactions. An example of the latter is the reaction in which kaolinite and montmorillonite are transformed to chlorite and/or illite (Muffler and White, 1969; Kendall, 1976a). With the exception of pyrite mineralization, the alteration of rocks above 800 m in the Magmamax wells and above 1000 m in the Woolsey well is subtle and can be detected only by means of careful x-ray diffraction and detailed petrographic analyses. The point to be emphasized is that these alteration effects have not changed the petrophysical properties (e.g., porosity and permeability) of the reservoir rocks any more than what is normally expected during the process of lithification via burial diagenesis.

Fig. 5-1. Well locations in the Salton Sea Geothermal Field. Drill cuttings from Magmamax Nos. 2 and 3 and Woolsey No. 1 were analyzed. In addition, porosity measurements were made on ore samples from Woolsey No. 1 and State of California No. 1. Based on USGS topographic map; well information provided by the California Division of Oil & Gas.

Since it is convenient to differentiate between the uppermost reservoir rocks and deeper units that have suffered changes in their petrophysical properties, the terms "altered" and "unaltered" will be used. The transition to altered rock is recognized on the basis of the first appearance of epidote. The epidote isograd corresponds reasonably well with Randall's (1974) definition of the "top of the metamorphic zone" as determined by means of well log analysis.

Major Structural Limits

The cap rock extends from the surface to a depth of approximately 325 m in the three wells. The uppermost 180 m of the cap rock consists of unconsolidated clay, silt, sand, and gravel. The interval from 180 to 325 m consists of anhydrite-rich evaporites in a carbonate-clay matrix and has low porosity and permeability.

There is a sharp transition between the cap rock and the underlying sequence of unaltered clastic sediments. The unaltered reservoir rocks extend from a depth of 325 m to approximately 825 m in the Magmamax wells and from 325 to 1000 m in Woolsey No. 1. The eastward thickening of the zone of unaltered rocks in the study area is a result of the gradually increasing depth to the zone of altered rocks over the same interval. The unaltered sequence is made up of indurated shales, siltstones and sandstones, the latter consisting of quartz and feldspar grains cemented with calcite and/or silica (Fig. 5-2).

The transition with depth to hydrothermally altered rocks is rather subtle. It is marked by clay-mineral transformations and the replacement of interstitial calcite by epidote (Fig. 5-2, right). The principal effect of hydrothermal alteration on the reservoir rocks in the SSGF has been the reduction of porosity and permeability. This is due to the fact that the degree of calcite cementation is variable in

Fig. 5-2. Photomicrograph drawings of (left) porous, unaltered sandstone from 783-m depth in Woolsey No. 1, (center) unaltered calcareous sandstone from 381-m depth in Magmamax No. 2, (right) hydrothermally altered sandstone from 1323-m depth in Magmamax No. 2. Scale bar = 100 μ m.

unaltered reservoir rocks whereas epidote cementation is pervasive in altered sandstones.

Porosity measurements on core samples from 783- and 1042-m depths in the Woolsey No. 1 well and from 1387- and 1477-m depths in State of California No. 1 indicate the existence of a vertical porosity gradient in the field (Fig. 5-3). A reduction in porosity with depth is not unexpected: it is a common feature of sedimentary basins and is likely to be enhanced in a geothermal environment by the presence of hot brine filling the interstitial pore space. In the area studied, the reservoir strata dip westward toward the center of the geothermal resource at an angle of 5 to 10°, indicated in the SP logs shown in Fig. 5-4. Therefore reservoir strata become progressively deeper and concomitantly less porous and permeable in going from the periphery of the field toward the center of the heat axis.

Drill cuttings and core samples indicate that the reservoir rocks in the geothermal field have been extensively fractured. The widths of filled fractures range from a few microns to a centimeter. Whereas the primary intergranular porosity in reservoir rocks is subject to irreversible self-sealing due to hydrothermal alteration, fractures can be considered as "renewable" porosity in that they can be reopened after having been sealed. Observations of cathodoluminescence of calcite fracture fillings commonly reveal two or more episodes of fracturing and deposition (Fig. 5-5). This suggests that the

Fig. 5-3. Plot of porosity versus depth for core samples from Woolsey No. 1 and State of California No. 1. Porosities calculated by means of the expression $\phi = 1 - (\rho_b / \rho_g)$, where b and g stand for bulk and grain, respectively.

seismicity in the Salton Trough may play a role in maintaining fracture porosity and permeability in reservoir rocks.

Spontaneous-potential, resistivity, and temperature logs have been commonly run in the

Fig. 5-4. Spontaneous-potential log correlation of the Magmamax and Woolsey wells. The use of shading is intended to help the reader visualize the author's correlations. The boundaries between the major rock units are also indicated.

Salton Sea geothermal wells after drilling and before setting liners. Spontaneous-potential logs give qualitative indications of the relative sandiness or shaliness of sedimentary strata and provide good indications of stratigraphic boundaries. As such,

Fig. 5-5. The composite vein occurs in a sample from 1164-m depth in Magmamax No. 3. The sequence of events in the formation of the vein is interpreted as follows: (1) fracturing and subsequent filling with calcite, (2) refracturing and filling with a second generation of calcite, (3) refracturing in higher temperature regime and filling with epidote. Calcite generations determined by cathodoluminescence. Scale bar = 0.5 mm.

they are useful for correlation purposes (Fig. 5-4). The sequence of regularly alternating sand and shale beds overlying a major shale break in the vicinity of 2000 ft in Woolsey No. 1 and 2500 ft in Magmamax Nos. 2 and 3 is the most readily correlatable interval in the section and is therefore useful in establishing the correlation pattern among the four wells (Randall, 1974). With the pattern established, it has been possible to make other unambiguous correlations above and below the key interval. The geologic picture that emerges from the proposed correlations is that of a structural basin whose axis or center lies to the northwest of Magmamax No. 2. This picture is in accordance with the cross section of the Salton Trough, and the magnitude of the westward dip of the strata correlates well with the dip measured in cores taken from Woolsey No. 1.

The cap rock in the four wells produces a rather featureless spontaneous-potential curve and as such is recognizable at the top of each log. The transition between unaltered and hydrothermally altered reservoir rocks is not readily apparent in the logs and has been determined by means of petrographic analysis of drill-cutting samples.

J. D. Tewhey

5.3 Geophysical Studies—Resource Assessment

Geophysical techniques have been employed in the study of the Salton Sea Geothermal Field. Work completed to date includes analysis and interpretation of data from well logs, deep-well temperature measurements, and resistivity, temperature, and seismic refraction surveys. An attempt has been made to unify the results of these studies and other published data into a self-consistent physical model of the Salton Sea geothermal system.

The word "reservoir" is often used as a convenience to describe a region from which hot fluid can be produced. However, "reservoir" does not accurately describe the Salton Sea geothermal system. Rather than being a "place where something is stored," this geothermal area (like most others) is a region of moving fluid that interacts with hot or cool rock to transport and concentrate heat. For our analogy of the system, we should use a "flow-through" water heater rather than a reservoir or tank of hot water. The flow-through system is driven either by thermal convection around a heat source associated with volcanic buttes, located

along the southern shore of the Salton Sea, or by fluid-density differences caused by salinity and recharge from the boundaries of the valley. The actual paths of fluid flow are influenced by the geologic structures in the valley, and those paths may change continuously with time as interaction with the fluid alters the matrix properties of the rock.

In order to assess the commercial value of the geothermal system associated with the Salton Sea field, we must understand the fluid circulation in the valley. The geophysical studies aid that understanding in several ways. The geologic structures and faults controlling the flow are delineated by resistivity data, electrical logs, and seismic refraction data. The regions where heat has been concentrated near the surface are found from thermal gradient measurements. *In situ* rock properties such as porosity and compressibility are deduced from electrical resistivity logs. Magnetic field observations and thermal gradients lead to the identification of possible driving forces that influence the total size of the system.

5.3.1 RESISTIVITY SURVEY

The Laboratory has sponsored an extensive resistivity survey of the vicinity of the Salton Sea Geothermal Field. The survey was performed by Geonometrics, Inc. (Meidav et al., 1976). Electrical currents as high as 200 amperes were employed to detect extremely low resistivities (less than 0.5 ohm-m) to depths of several kilometers. The survey consisted of 60 soundings with a maximum separation of over 5 km and approximately 60 km of dipole survey lines.

The survey indicated that a large volume of the sedimentary rock is highly conductive (see Fig. 5-6). The observed conductive rock lies between the surface and a depth of 2 km. The conductivity-thickness product (or conductance) of these rocks is greatest in the area of the drilled field, but the high-conductance region is extended along the axis of the valley. Two other features are evident from the resistivity soundings:

1. Adjacent soundings are sufficiently different to cause Meidav et al. (1976) to interpret the area as criss-crossed by faults.
2. A shallow (500 to 1000 m) resistive layer is

also seen in the drilled area, and that layer may be continuous across the faults.

The results of the resistivity survey contribute to our understanding of the dynamic system in three ways (Kasameyer, 1976):

1. The physical boundaries of a porous reservoir of saline fluid can be inferred. Low-resistivity zones result when porous rocks are saturated with hot and/or saline fluid. The survey found a low-resistivity anomaly extending to the southeast from the known geothermal field. Extremely low resistivities (0.5 ohm-m) are found in the vicinity of a "cool" well (Sardi No. 1), and consequently the anomaly is inferred to be caused by porous rock saturated with salty fluid. The resistivity increases rapidly to the northeast or southwest of the known field. That increase indicates either a loss of porosity or a lower salinity fluid. In either case, the resistivity increase indicates that there is a physical boundary either between regions of porous and tight rock or between two regions of porous rock with different pore fluids. In the Geonometrics, Inc., report, it is suggested that faults form the bound-

Fig. 5-6. Conductance map of surveyed area. Dots indicate the location of soundings; broken line locates the fault; conductance in siemens. Some sounding curves do not continue to large enough spacings to shown an S line. For these, minimum values of conductance have been plotted (■).

aries of the reservoir containing both hot and cool saline fluid.

2. The resistivity results indicate the existence of a "shallow" resistive layer extending outward from the known field. Meidav et al. suggest that this resistive zone is the "metamorphic zone" of Randall (1974). (The "metamorphic zone" appears on SSGF well logs as a region where shale resistivity increases.) Another interpretation of this resistive layer is possible. Many of the well logs also show a depth interval where the sand resistivity is high, either due to reduced porosity or low-salinity fluids. This depth interval coincides with the upper boundary of convection in at least two wells (as inferred from temperature data from those wells). If conduction dominates above the shallow resistive layer, temperatures at that depth can be estimated by extrapolating surface thermal gradient data.

3. The evidence that the region is complex and probably heavily faulted indicates that our efforts to predict the production behavior of wells must consider the effects of those fractures on heat and fluid flow (Section 5.4.1) and that the vertical permeability between aquifers at different depths cannot be assumed to be negligible and must be determined by field tests (Section 5.4.5).

P. W. Kasameyer

5.3.2 WELL-LOG RESISTIVITY EVALUATION

We have acquired SP and resistivity logs for 16 wells within the Salton Sea Geothermal Field. The logs have been employed (1) to provide constraints for the interpretation of the surface resistivity survey results; (2) for subsurface geologic correlations (Section 5.2); and (3) to provide data for understanding the physical properties and processes at work within the geothermal system.

Only preliminary work is complete at this time. The following information from the well logs has been tabulated as a function of depth in 16 wells: sand percentage, maximum spontaneous-potential (SP) shift from shale line, log resistivity associated with SP on shale line, and log resistivity associated with SP shifted from shale line.

An example of the analysis of well log is shown in Fig. 5-7. The broken line is an interpretation of a resistivity-sounding curve indicating the agreement between surface and borehole measurements.

One example of a useful physical property to be

derived from well logs is the long-term compressibility of "reservoir" sands. The compressibility is needed to determine the storativity for fluid-flow models and also for estimating aquifer compaction due to a reduction in pore pressure during production.

This method for inferring compressibility has several advantages:

1. A "normal" resistivity-depth curve can be established for any given portion of a resource.
2. Departures from the type "normal" curve for a given region can then be interpreted in terms of significant changes in lithology or chemical alteration of reservoir rocks.
3. Long-term compaction of the reservoir that has occurred through geologic time can be resolved.
4. The rate dependence of compaction can be studied by comparing data with results of laboratory compressibility measurements on reservoir core samples.

Fig. 5-7. Well-log and sounding interpretation at the Elmore No. 1 well. Sand percentages were estimated every 30 m; induction log resistivity curve (solid line) has been smoothed.

It can be assumed that long-term decreases in the pore volume of the rock depend only on the effective stress P_e :

$$P_e(z) = (\rho - \rho_f)gz, \quad (5-1)$$

where z is the depth, ρ_f is the fluid density, ρ is the rock density, and g is the gravitational constant.

If the pore-fluid pressure is lowered, a new larger effective stress P_e' will be established. It would be easy to estimate the compaction if a rock sample from depth z could be transported to the laboratory without changing its pore pressure. It could then be subjected to an increased effective stress while pore-volume changes were monitored. Alternatively, we could take unconsolidated sediment and measure pore-volume decrease as a function of increasing effective stress.

Nature has performed the latter experiment for us in the Salton Trough, where there has been nearly continuous deposition for thousands of years. Sedimentary rocks at a depth z have been subjected to a monotonically increasing effective stress up to $P_e(z)$. Rock compressibility is determined by using electric logs to estimate the change of porosity with depth. For sandstones, the porosity ϕ can be related to the rock resistivity R and the pore-fluid resistivity R_f at any depth:

$$R(z) = R_f(z) \phi(z)^{-2}. \quad (5-2)$$

The porosity change with fluid pressure can be calculated from

$$\frac{\partial \phi}{\partial P_e} = \frac{\partial \phi}{\partial z} \left(\frac{\partial P_e}{\partial z} \right)^{-1} = \frac{1}{(\rho - \rho_f)g} \frac{\partial \phi}{\partial z}, \quad (5-3)$$

or, using Eq. (5-2) and ignoring $\partial R_f / \partial z$, from Eqs. (5-4) and (5-5):

Fig. 5-8. Variation of well-log resistivity (for sands) with depth in Magmamax No. 1.

$$\frac{\partial \phi}{\partial P_e} = \frac{\phi_0}{2R(\rho - \rho_f)g} \frac{\partial R}{\partial z} \quad (5-4)$$

or

$$\frac{\partial \phi}{\partial P_e} = \frac{z}{2P_e} \frac{\partial \ln(R)}{\partial z} \quad (5-5)$$

Preliminary values of R (for sands) at different depths for Magmamax No. 1 are shown in Fig. 5-8. Results indicate that

$$\Delta \phi \simeq \frac{0.35 \phi_0 z}{1000} \frac{\Delta P_e}{P_e} \quad (5-6)$$

Compaction of a layer is calculated by assuming

the porosity decrease is caused by a change in thickness H :

$$\Delta H = \Delta \phi \cdot H = 0.35 \rho_0 \frac{z}{1000} \frac{\Delta P_e}{P_e} \quad (5-7)$$

For a 5% decrease in effective stress in a 600-ft-thick layer with 20% porosity centered about a depth of 2000 ft, the predicted compaction is slightly over 4 ft.

Application of this method will require an analysis of the pore-fluid resistivity variation and a determination of "true" resistivity from the well logs. Furthermore, analysis of many logs from the field will be required in order to justify our assumption of uniformity.

P. W. Kasameyer
J. F. Schatz

5.3.3 SEISMIC REFRACTION SURVEY

The Laboratory has sponsored a large-scale seismic refraction survey of the Salton Sea Geothermal Field. The refraction survey was performed by Prof. S. Biehler and associates from the University of California at Riverside.

Locations for two reversed seismic refraction profiles are shown on the gravity-anomaly map in Fig. 5-9. Each profile is at least 20 km long and has one end inside the drilled geothermal field, the area bounded by the 975-milligal gravity contour.

The seismic data presented in Fig. 5-10 were recorded along profile 1, and the shot point A was located near Obsidian Butte. A maximum of three arrivals are shown for recording stations up to 7000 m from the shot point. The quality of the data is excellent, and three layers with distinct seismic velocities can be resolved. Also, data recorded farther from the shot point provide evidence of a fourth layer.

The 4060-m/sec arrival is delayed by more than 0.1 sec at a distance of 5000 m from the shot point. An interpretation of this data (S. Biehler, 1976) is shown in Fig. 5-11. The arrival-time delay is thought to result from a nearly vertical fault with an apparent vertical offset of 220 m. This is the simplest interpretation that fits the observations, but other, more complicated models involving hidden layers are possible.

Fig. 5-9. Bouguer gravity anomaly map of the Niland-Brawley area (Biehler et al., 1964). Heavy solid lines show locations of two seismic refraction profiles; the cross (+) represents location of the fault as determined from profile 1 (contours in milligals).

Fig. 5-10. Seismic refraction data along profile 1 (see Fig. 5-9). Each dot represents an arrival time picked from the field record; velocities along refraction lines in meters per second.

The fault is assumed to strike north-west-southeast, parallel to many other faults seen in the valley (Fig. 5-6). The location of the fault coincides with the sharpest boundary of the electrical conductivity anomaly (Fig. 5-6). Data from the recently expanded U.S. Geological Survey (USGS) seismic network at the Salton Sea (Schnapp and

Fig. 5-11. Cross section along profile 1 (see Fig. 5-9), showing fault interpretation and velocity layers (meters per second). Vertical exaggeration 2:1.

Fuis, 1977) show no microearthquakes along the fault. The inactive fault probably acts as a barrier to flow because of the misalignment of permeable beds.

P. W. Kasameyer

5.3.4 TEMPERATURE-GRADIENT ANALYSIS

Our work so far has involved analysis of existing temperature data for the Salton Sea Geothermal Field. Results are being used to design specifications for a survey of thermal gradients over the southern part of the Salton Sea. An understanding of the circulating geothermal system is necessary in order to estimate temperatures at depth from surface data and to predict the economic value of a resource from the temperatures at depth. Because heat in the system is transported by fluid flow as well as by conduction, the temperature gradient cannot be assumed to be constant from the surface to the depths of interest. In fact the highest thermal gradients (such as those measured by T. Lee (personal communication, 1976)) in the northeastern part of the Salton Sea Geothermal Field (near the River Ranch No. 1 well) may be associated with circulation of near-surface fluids and do not, therefore, indicate higher temperatures at greater depth.

The relationship between temperature gradient and exploitable resource may be even more complicated. It might actually be advantageous to locate production wells in regions of moderate surface gradient on the flanks of high-gradient anomalies (Barkman and Campbell, 1976; Tewhey, 1977). In these regions, the gradient remains constant with depth, indicating that convection is not important and that permeability may be greater due to less interaction between rocks and fluid. The large flow rates through a thick section may compensate for the greater depth to which wells must be drilled in order to reach commercial temperatures.

Present estimates of the size of the Salton Sea geothermal resource (Towse, 1975) and the legal definition of the Salton Sea KGRA are based on surface thermal gradient contours drawn by Combs (1971) (Fig. 5-12). These contours are not a reliable indicator of the actual surface gradient in the Salton

Fig. 5-12. Known geothermal resource areas (KGRAs) and temperature information (from Combs et al., 1971).

Sea KGRA since they were based only on a few shallow gradient measurements. Furthermore, the shape of the contours was chosen to correspond with the Bouguer gravity anomaly centered over the Salton Sea KGRA. A considerable amount of thermal gradient data is available from deep wells, as shown in Fig. 5-13. Combs' gradient contours, based on only two measurements in the field, do not match the deep-well observations, and the contours are incorrectly shaped. Approximately 50 square miles of reservoir has been inferred to underlie the Salton Sea and is included in the KGRA based primarily on the shape of the $0.11^{\circ}\text{C}/\text{m}$ contour, which encircles the drilled portion of the KGRA. The justification for including that area is tenuous.

We are planning a survey of thermal gradients in the portion of the KGRA that underlies the southern end of the Salton Sea. The survey may involve a combination of standard 30- to 100-m drill holes and 1- to 2-m "short-probe" measurements. The short-probe measurements have been utilized by P. Wilde of the University of California at Berkeley and T. Lee of the University of California at Riverside. The measurements are quick and inexpensive, allowing coverage of a very large area, but can resolve only very high gradients in a shallow sea where the bottom temperature fluctuates.

To aid the planning and interpretation of the thermal gradient survey, models of the heat source and resulting fluid flow have been investigated (Younker and Kasameyer, 1976). For four different models, the approximate near-surface temperature distribution has been calculated and compared to the observed temperatures. Each model predicts a different geometry for the unmeasured anomaly under the sea. The actual anomaly may result from a combination of several of these models. The models are summarized in Table 5-1. The calculated thermal gradient distributions for each model are discussed below.

For each model, different geophysical tools (in addition to thermal gradient measurements) would be useful for resource assessment: magnetic and gravity surveys for model 2A, passive seismic observations to resolve the plate boundary for model 2B, seismic surveying and resistivity to look for continuity of layers for model 1A, and perhaps deep-probing electromagnetic sounding for model 1B. The validity of each model can be tested by comparing our knowledge of the field with the results of numerical simulations of each model.

Fig. 5-13. Thermal gradient ($^{\circ}\text{C}/\text{m}$) in upper 500 ft of the Salton Sea Geothermal Field. The approximate locations of Combs' contour lines are shown. These contours do not fit the data from geothermal wells.

Models with No Localized Heat Source

In models 1A and 1B the anomaly is assumed to be a result of high temperatures at a moderately shallow depth throughout the Salton Trough. Heat-flow anomalies occur at particular locations because of thermal conductivity differences related to lithology (model 1A) or because of the cell geometry of free convection (model 1B). The important implication of these models is that the anomaly geometry is not determined by the shape of a heat source.

Helgeson (1968) suggested that the Salton Sea anomaly is caused in part by the presence of a thick, impermeable, low-conductivity cap rock in a region of generally high heat flow. The thermal gradients are highest where the cap is thickest. Calculations show that the anomaly is not caused solely by the conduction below an insulating cap rock. Steady-state conductive geotherms for two-layer geometries (Fig. 5-14) differ from the observed temperatures in two ways.

First, for a specified temperature at 7000 ft, high gradients correspond to the thinnest caps (curve B). Second, in order to reproduce the observed data (curve D) a conductivity contrast (K_2/K_1) of more than 6 would be necessary. Such a wide range of thermal conductivities is not found in saturated sedimentary rock. Clearly, the rocks below 1500 ft

Table 5-1. Salton Sea KGRA thermal anomaly models

Model	Heat source	Factors controlling geometry of anomalies	Anomaly predicted at Sea?
1A	High regional heat flow due to crustal thinning	Lithology controlling convection: Thickness of cap rock or location of permeable sediments adequate for convection	Unknown: Only if appropriate lithologic conditions exist
1B	High regional heat flow due to crustal thinning	Geometry of convection cells that are not determined by permeability distribution	Unknown: Must learn what controls cell geometry
2A	Single intrusive event (transient source)	Distance from intrusive bodies Size of intrusive bodies Age of intrusive bodies	Yes, equidistant about buttes, magnetic or gravity anomalies
2B	Continuing tectonic intrusions related to crustal rifting (steady-state source)	Distance from spreading centers Rate of spreading Depth of intrusion Length of spreading center	Yes, exact locations indicated by seismic activity and active faults

allow the transport of heat by a more effective means than conduction. That means must be by fluid motion, driven either by salinity gradients (advection) or by density differences due to temperature gradients (convection).

The observed relationship between cap thickness and gradient for a uniformly thin crust can be explained by an examination of the convection in individual sand layers. A thicker cap raises the temperature beneath the cap, making convection a more effective mechanism of heat transport. In most studies of the geothermal system, the convection is assumed to take place in cells whose dimension is 4000 to 7000 ft. Recent work, however, has strongly questioned the feasibility of such large cells in the sedimentary sequence.

Towse and Palmer (1976) have identified in the reservoir sands several major shale beds that are over 40 ft thick and would surely provide impermeable barriers to convective flow if they are not extensively fractured. By comparing well logs to detailed temperature logs, we see high gradients in regions where the sand percentage is high but the individual beds are thin, indicating that even thin shale beds may be extensive enough to interfere with convection. Some evidence is presented in Fig. 5-7, which shows modest gradients at depths from 500 to 1000 m, where sand beds are thin, but near-zero gradients exist below 1400 m, where sand beds are thick. Recent work at Riverside (Kendall, 1976b) using oxygen isotope data also suggests that

the reservoir is divided into several separate hydrologic systems.

Because of this new information, it has been proposed that the Salton Sea reservoir is divided into several individually convecting sand units, hydrologically separated from each other by thin shale units. Such an interpretation is certainly consistent with recent models of deltaic sedimentation. Lateral migration of depositional environments makes it highly unlikely that a layer of sandstones capable of supporting 4000-ft convection cells would be deposited. Sand units in a deltaic region representing bay-mouth bars, point bars, and beach deposits are typically separated from each other by fine-grained sediments in backswamp and lagoon deposits as the locus of sedimentation shifts. Such sand bodies are rarely more than 100 m thick and commonly less than 30 m thick. A study was carried out to investigate the possibility of the development of convection cells in individual sand units using conventional convection criterion and data on the Salton Sea reservoir sands.

For a homogeneous saturated permeable layer of thickness H , the parameter controlling convection is given by Elder (1967) as

$$n = \frac{K\alpha \Delta T g H}{K_m \nu} ,$$

Fig. 5-14. Conductive models of heat transfer compared to temperature-depth profiles for the Magma/SDG&E wells and some nearest neighbor wells.

where

- K = permeability of the layer
- α = coefficient of volume expansion of the fluid
- g = absolute value of acceleration due to gravity
- K_m = thermal diffusivity of the saturated medium
- ν = kinematic viscosity of the convecting fluid
- H = thickness of the layer
- ΔT = temperature difference across the layer

The critical value for the onset of convection for a medium of infinite extent bounded above and

below by impervious conducting boundaries was determined to be $4\pi^2$ by Lapwood (1948).

In order to accurately determine the likelihood of convection developing in a sand of a given thickness, permeability, and depth, it is necessary to investigate the variation of the physical properties of the liquid with temperature and pressure. Convection depends strongly on the coefficient of expansion, kinematic viscosity, and the thermal diffusivity of the saturated medium. All of these parameters are highly dependent on temperature. The conjugate variation of these three parameters makes convection much stronger when the temperature increases. Thus it might be expected that sand units of given thickness and permeability

would be more likely to convect if the temperature were higher.

The calculated Rayleigh numbers based on temperature-dependent properties indicate that changing the temperature at the top of the sands from 100 to 200°C (by thickening the cap from 600 to 2000 ft) decreases the minimum bed size for stable convection by 60%. Therefore the regions of thick cap could have high gradients partly because the low-conductivity cap causes high temperatures and efficient heat transport at depth.

The possible development of the existing geotherms was investigated using computer simulation of the time-dependent temperature distribution after the temperature at the bottom of the sediment pile was raised from 200 to 400°C. In this one-dimensional model convection was simulated only by specifying a large, temperature-dependent conductivity for the sand layers and having that conductivity depend linearly on sand-layer size. Three results were important:

1. The temperature distributions reached steady state in less than 80,000 years, a short time compared to the age of the Salton Trough.
2. The shape of the Elmore No. 1 well temperature profile could be matched with a three-layer model (cap, thin sands, thick sands).
3. For this model to fit observations, deposition and hydrothermal alteration cannot have reduced the permeability in the thick sands.

It is also possible to have a localized anomaly above a uniform or nearly uniform heat source (model 1B). Ribando et al. (1976) have calculated the temperature distribution in a convecting system within a homogeneous porous medium heated uniformly from below. Calculated isotherms for a single cell are shown in Fig. 5-15. The geotherms from wells at the upwelling limb (A) and at the downwelling limb (B) are shown in Fig. 5-16.

There is nothing physically different about the lithology at A and B, nor is the heat source stronger at A. Yet the calculated temperature profiles are quite different, and their shapes are similar to the extremes of geotherms observed in the field (i.e., Elmore No. 1 and Sinclair No. 3, Fig. 5-14). For these calculations, the actual location of the cell is arbitrary. However, in practice, the location of a cell could be determined by very minor variations in permeability, layer thickness, or temperature. Consequently it is possible that the cell geometry and location do not reflect anything about a heat source or lithology.

Fig. 5-15. Isotherms (solid lines) and stream lines (broken lines) for thermal convection in a constant permeability layer with an impermeable top. $Ra_f = 100$.

Models with a Localized Heat Source

For models 2A and 2B, a local heat source is assumed to cause the Salton Sea geothermal system. The heat sources for model 2A are separate intrusions, as indicated by their characteristic magnetic anomaly. Continuous intrusions resulting from crustal spreading are the heat source for model 2B.

Griscom and Muffler (1971) interpreted the magnetic anomalies at the Salton Sea field. Three different sets of intrusions could produce the observed magnetic anomaly. The observed thermal gradient anomaly has a maximum value at least five times background and is 5 to 10 miles wide. We have calculated transient (conductive) gradient anomalies for each set of intrusions and compared them to the observed anomaly.

Small-Scale Anomalies. Small and intense magnetic anomalies are associated with the volcanic buttes and indicate "pencillike" intrusions of small radius (<200 m). Such a small intrusion can only influence the thermal gradients strongly over a distance of less than 500 m and for less than 10,000 years. They contribute little to the observed heat-flow anomaly.

Moderate-Scale Anomalies. Two elliptical anomalies 3 to 4 miles wide indicate that tabular dikes have intruded the sedimentary rocks beneath the field and beneath the Salton Sea itself. The magnetic field anomaly cannot resolve the size of in-

Fig. 5-16. Temperature profiles of the two wells shown in Fig. 5-15.

dividual dikes. If they were as large as 1 km in thickness, then they could explain the observed heat flow (Randall, 1974). However, if the individual dikes are as small as 60 m (a physically reasonable size), then they can only produce the heat-flow anomaly if intruded close enough together and rapidly enough (within 10,000 years) to allow their effects to become additive. This is certainly a possible cause of the anomaly.

Large-Scale Anomaly. A large-scale anomaly extends along the axis of the Salton Sea Trough, indicating a deep (10,000 ft) intrusion extending well beyond the boundaries of the drilled field. Transient calculations indicate that such a magma body could produce the high heat flow observed for 20,000 to 200,000 years after emplacement. However, the heat-flow anomaly from such a body would cover a much larger area than the observed heat-flow anomaly. Consequently, the large-scale intrusion can be the source of the anomaly only if the part of the intrusion near the SSGF is younger than 200,000 years and the part to the southwest is considerably older.

The observed heat-flow anomaly could be produced by either the medium-scale or the large-scale intrusive bodies, if the age of those bodies is appropriate. Consequently, similar heat-flow anomalies might be expected to be associated with the magnetic anomalies in the Salton Sea, but only if those anomalies also represent intrusions of the appropriate age.

Fortunately the concept of crustal spreading (model 2A) provides a basis for estimating the ages of the intrusions under the Salton Sea. Elders et al. (1972) traced the Pacific-North America plate boundary through the Salton Trough and indicated that some geothermal areas (Salton Sea, Brawley, and Cerro Prieto) are associated with spreading centers along that boundary (Fig. 5-17). Recent earthquake-epicenter data may indicate the detailed location of the plate boundary and thus give a clue to the interpretation of the magnetic anomaly. Johnson and Hadley (1975) used observations of an earthquake swarm to locate an offset of the Imperial Fault near Brawley. Lee (personal communication, 1976) used a portable seismic network to locate activity on the north end of the Brawley Fault near Obsidian Butte. Preliminary data from the recently installed LLL Imperial Valley Environmental Project addition to the USGS seismic network is shown in Fig. 5-18 (from Schnapp and Fuis, 1977).

Fig. 5-17. Inferred spread centers in the Salton Trough. From Elders et al. (1976).

Fig. 5-18. Location of earthquake epicenters in the Imperial Valley with respect to major faults for the period October 1, 1976, through December 31, 1976. Solid triangles are seismograph stations in the Imperial Valley network installed in 1973. Solid circles are the seismograph stations installed in November 1976. Tentative fault locations are shown in broken lines. After Schnapp and Fuis (1977).

Fig. 5-19. Magnetic anomaly associated with the Salton Sea KGRA. (Aeromagnetic map after Griscom and Muffler, 1971.)

Earthquakes recorded during a short 3-month period suggest that there are three or four spreading centers separated by faults that are connected to the Brawley Fault and to the Banning-Mission Creek section of the San Andreas Fault system. In Fig. 5-19 we see that the tentative faults from epicenters outline the magnetic anomalies. If those anomalies reflect intrusions related to spreading centers, then

we can expect the highest heat flow and geothermal potential to be centered along the fault system. Our off-shore temperature survey will be designed to test that hypothesis.

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5.4 Reservoir Engineering — Resource Assessment

5.4.1 HEAT AND MASS TRANSPORT IN LIQUID-DOMINATED GEOTHERMAL RESERVOIRS*■

A computer code has been developed to simulate heat and mass transfer in hydrothermal reservoirs of the type found in the Imperial Valley of California. Rather than seeking a general code that can solve a large class of problems, we have developed a rapid solution to a particular problem. The code determines the pressure distribution and flow fronts of injected fluid within a single homogeneous, nonleaky, liquid-filled aquifer of uniform thickness and infinite extent. The permeability of the aquifer may be anisotropic. The fluid is assumed to flow horizontally within an array of arbitrarily placed production and injection wells. The code has been used to evaluate well use at the Magma Power Company/San Diego Gas & Electric Company geothermal site in the Salton Sea Geothermal Field. Accurate estimates for thermal and mass breakthrough are useful in predicting the time-dependent changes in temperature and salinity, respectively, at producing wells.

Two features of this computer code are important: an analytical solution for the pressure distribution is used so that the code runs rapidly, and successive flow fronts of the injected fluid are displayed graphically to allow a convenient image of the flow distribution for an array of wells.

The analytical solution for the time-dependent pressure distribution (Walton, 1970) can be differentiated in order to determine the pressure gradient. Marker particles are placed at the injection wells and moved with a velocity based on Darcy's law:

$$\bar{v}(x,y,t) = \frac{\bar{k}}{\mu\theta} \nabla p(x,y,t),$$

where v is the fluid-front velocity, k is the permeability tensor, θ is the porosity, and p is the pressure.

Movement of each fluid front can be visualized as an expanding elliptical cylinder distorted by other wells in the field. Each cylinder wall is divided into a number of strips, each extending vertically through the reservoir. Each strip migrates independently of its neighbors with a velocity that is continually recalculated as the fluid front propagates through the reservoir. The breakthrough time and the amount of injected fluid at each production well are calculated.

The temperature distribution in the reservoir is approximated by assuming instantaneous local equilibrium between pore fluid and rock matrix, and ignoring thermal conduction and dispersion in the fluid. A thermal front around each injector separates regions of cooled rock and fluid from the hot reservoir (Bodvarsson, 1974; Kasameyer and Schroeder, 1976). Because the injected fluid removes heat from the rock, the thermal front velocity v_T is less than the fluid-front velocity:

$$\bar{v}_T = \bar{v} \frac{\rho_f C_f \theta}{\rho_f C_f \theta + \rho_r C_r (1 - \theta)},$$

where ρ_f and ρ_r are the fluid and rock densities and C_f and C_r are the fluid and rock heat capacities. The breakthrough time and percentage of cooled fluid at each production well are also calculated.

The code has been used to study flow patterns induced by the operation of wells supporting the Geothermal Loop Experimental Facility (GLEF)

*From a paper presented at the Geothermal Resources Council Annual Meeting, May 9-11, 1977, San Diego, California.

operated by the San Diego Gas & Electric Company near Calipatria, California. The approximate times of mass and thermal breakthrough were estimated. Estimates for thermal breakthrough are important to ensure that power production will continue at the desired level for the expected lifetime of the facility. Mass breakthrough estimates are also important, since significant changes in fluid chemistry may affect the performance of plant equipment.

In addition, the effect of horizontally anisotropic permeability on breakthrough time was examined, because permeability along the axis of the Imperial Valley may be enhanced by fractures and faults as well as by buried stream channels striking north-west-southeast.

The parameters used for the calculations are shown in Table 5-2. The permeability and thickness shown are estimates based on a few well tests (Schroeder, 1976); more accurate calculations will be made as more reservoir data are obtained. The actual production history for the Magma/SDG&E site will be influenced by several factors not included in our model:

1. Production and injection possibly at different depths, separated by aquitards.
2. Fluid leakage from beneath the aquifer.
3. Lateral permeability changes.
4. Flow in fractures.

The results of calculations are shown in Figs. 5-20 and 5-21. Fluid is produced from the Magma No. 1 and Woolsey No. 1 wells and 80% of the fluid is injected in equal amounts into the Magma No. 2 and Magma No. 3 wells. Marker particles start at the injectors, and their locations are shown every 2 years for 30 years. The display of displacement fronts allows easy

Table 5-2. Reservoir properties assumed for the GLEF site

Permeability k	$1.00 \times 10^{-12} \text{ m}^2$
Viscosity μ	$2 \times 10^{-4} \text{ Pa-sec}$
Compressibility c	$1.45 \times 10^{-9} \text{ Pa}^{-1}$
Well radius r_w	0.12 m
Reservoir thickness h	200 m
Porosity	0.20
Transmissivity $T = kh/\mu$	$1.0 \times 10^{-8} \text{ m}^3/\text{sPa}$
Storativity $S = ch$	$2.9 \times 10^{-7} \text{ m/Pa}$
Discharge well flow rate Q	$-0.0504 \text{ m}^3/\text{sec}$
Injection well flow rate Q	$+0.0403 \text{ m}^3/\text{sec}$

Fig. 5-20. San Diego Gas & Electric Company's geothermal loop experimental site. Fluid particle displacement fronts for isotropic permeability. Successive fronts are 2 years apart.

Fig. 5-21. San Diego Gas & Electric Company's geothermal loop experimental site. Fluid particle displacement fronts for anisotropic permeability ($k_{NW} = 9k_{NE}$). Successive fronts are 2 years apart.

visualization of what occurs. Injected fluid first appears at Magmamax No. 1 after 15 years of operation but does not come close to Woolsey No. 1 in 30 years. The time to thermal breakthrough, however, is two to three times longer. The code can be used to optimize exploitation strategies. For example, the breakthrough time to Magmamax No. 1 could be delayed by injecting a greater percentage of fluid into Magmamax No. 2.

Figure 5-21 shows the flow fronts if the permeability is nine times as great along a north-west-southeast strike. Breakthrough occurs 35%

sooner at Magmamax No. 1 and is also important at Woolsey No. 1. Anisotropic flow properties can alter the predicted breakthrough times considerably.

In summary, an idealized, rapid calculation allows study of flow patterns around geothermal wells and can be used in the design of arrays of geothermal wells.

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5.4.2 THERMAL DEPLETION OF GEOTHERMAL RESERVOIRS WITH FRACTURE AND PORE PERMEABILITY†

The useful lifetime of a geothermal resource is usually calculated by assuming that fluid will be produced from, and injected into, a uniform porous medium. However, most geothermal systems are found in fractured rock. If the injection and production wells intersect connected fractures, the injected fluid may cool the production wells much sooner than would be predicted from calculations of flow in a porous medium.

We have developed a "quick and dirty" method for calculating how much sooner that cooling will occur (Kasameyer and Schroeder, 1975, 1976). In this section we discuss the basic assumptions of the method and show how it can be applied to the Salton Sea Geothermal Field and the Raft River System.

Solution for Flow in a Porous Medium

We model a finite hot-water reservoir produced at a constant flow rate, with fluid replenished either by injection or by cool recharge at the boundaries. We assume that an idealized well distribution can be found that allows a specified flow rate and that produces *all* of the original fluid from the reservoir before any injected fluid has been produced. Furthermore, we assume that there is no pressure drawdown or flashing, that the fluid moves with piston displacement through the pores, and that the pore fluid and matrix come to thermal equilibrium instantaneously. All these assumptions lead to an overestimate of the production temperature.

An analytical solution for this idealized problem

of heat transfer has been discussed by Bodvarsson (1974). A steep temperature front moves through the system, with no change in shape with time and with a lower velocity than the fluid front. Ahead of the temperature front, the reservoir retains its initial temperature. Behind the front, enough heat has been taken from the rocks to cool them to the injection temperature.

Solution in the Presence of Fractures

A family of fractures is assumed to exist parallel to the direction of flow. The fractures are characterized by a permeability k_{fr} and a spacing D . (For the results presented here, the fractures are tight enough for water storage in them to be negligible.) The fractures are assumed to have no effect on the pressure field, so that the flow stream lines are parallel in the porous rock and in the fractures, but the flow velocities are different.

The solution of a problem with two distinct velocities by a finite-difference method (e.g., Kasameyer and Schroeder, 1975) is not efficient if the velocities are quite different. In that case, time steps must be determined by the most rapid velocity, and calculations take a long time when fractures are important. An approximate solution requiring few time steps has been developed. The reservoir is conceptually divided into 10 regions of equal volume. The boundaries of the regions coincide with flow fronts of the injected fluid so that the fluid in the pores and the fluid in the fractures both flow through the regions in series (see Fig. 5-22). For each region, we write pairs of approximate

†From a paper presented at the Second Workshop on Geothermal Reservoir Engineering, Stanford Geothermal Program, December 1-3, 1976, Stanford, California.

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Fig. 5-22. Division of reservoir into a small number of regions.

equations relating the temperature of the fluid in the fractures *averaged* throughout the region, T_{fr} , to the *average* temperature of the saturating fluid, T_s . The 10 pairs of coupled first-order equations are solved analytically by assuming constant coefficients during time intervals that are much longer than those appropriate for the finite-difference method.

The equations for the i th region are presented here in dimensionless form (see Kasameyer and Schroeder, 1976, for the derivations). The times have been multiplied by α , defined by $\alpha = \text{thermal diffusivity} / (D/2)^2$.

$$\frac{dT_{fr}}{dt} = \frac{-R_q(1+R_\mu)}{R_\mu(1+R_q)} \frac{M}{\tau^*} (T_{fr} - T_{fr0}) + H,$$

$$\frac{dT_s}{dt} = \frac{-(1+R_\mu)}{(1+R_q)} \frac{M}{\tau^*} (T_s - T_{s0}) - R_\mu H.$$

The equations depend only on three dimensionless constants:

$$R_q = \frac{\text{flow in fractures}}{\text{flow in pores}},$$

$$\tau^* = \alpha \tau,$$

where τ is the lifetime based on a porous flow calculation, and

$$R_\mu = \frac{\text{heat stored in fractures}}{\text{heat stored in saturated rock}}.$$

The fluid enters the fractures and pores of region i at temperatures T_{fr0} and T_{s0} , respectively. These temperatures are determined from the solution for region $i - 1$ or by the reinjection temperature if $i = 1$.

The term H is the heat conducted from the saturated rock into the fractures. That term is approximated by an expression depending only on the time and the *instantaneous* values and derivatives of the average temperatures.

$$H = \frac{F(t)}{R_\mu} \left[\frac{1 - T_{fr}}{(\pi t)^{1/2}} - \frac{2}{R_\mu} \left(\frac{t}{\pi} \right)^{1/2} \frac{dT_{fr}}{dt} \right] + \frac{2[1 - F(t)]}{R_\mu} (T_s - T_{fr}).$$

The function $F(t)$ varies smoothly from 1 at early times to 0 at late times.

The approximation of H is justified by the close agreement of our calculations of the temperature in fractured impermeable rock with those of Gringarten et al. (1975), shown in Fig. 5-23. Our

Fig. 5-23. Comparison of our calculated curves for the output temperature from fractured impermeable rock (broken) with those of Gringarten et al. (1975) (solid). Their values have been converted to our dimensionless format, where $t^* = \alpha t$.

answers differ from those of Gringarten et al. because (1) we overestimate the heat transfer to the fracture fluid at early times and (2) the thermal front is smoothed out at late times because of averaging over large regions.

Correction Factors for Porous-Flow Models

A set of calculated production temperature histories is shown in Fig. 5-24. Results from many such calculations can be summarized in one figure by calculating the time t_f at which the production temperature falls below a specified value. That value would normally be determined from power-generating equipment. For the examples presented below, we have chosen a value of 0.8. The ratio of t_f/τ for different fracture systems and production rates is a correction factor for the useful lifetime.

The values of that correction factor for small R_μ are contoured in Fig. 5-25. The contours depend on R_μ and τ^* . For no flow in fractures ($R_q < 1$) or for slow removal of fluid ($r \gg 1/\alpha$), the porous-medium calculations are correct. If those conditions are not met, the correction factor can be determined from this diagram.

Fig. 5-24. Thermal depletion curves for different fracture spacings D (in meters). The parameters were chosen so that all the original pore fluid would be produced after 20 years, and the useful lifetime τ based on the exact porous-flow calculation was 66 years.

Fig. 5-25. Correction factor for lifetime estimates. The production temperature falls to 0.8 at t_f . The ratio t_f/τ is contoured for different flow distribution (R_q) and production rates τ^* . The contour where the factor equals 0.20 is distorted because of our approximation of the term H . The fracture spacings D are appropriate for the Salton Sea Geothermal Field example.

Fig. 5-26. The effect of production rate on the correction factor. If the fracture spacing is about 10 m, more than twice the energy can be removed from the system at the slow production rate ($\tau = 120$ years) than at the fast rate ($\tau = 30$ years).

Examples

The Salton Sea Geothermal Field. The τ^* values have been related to fracture spacings D by assuming parameters appropriate for the Salton Sea Geothermal Field (Fig. 5-25). Two scales of fracture systems are seen in that field. Fractures are seen in cores with a spacing of less than 1 m. From Fig. 5-25 we see that flow in these fractures will not shorten the useful lifetime of the field. Faults hundreds of meters apart influence the flow in several wells. If these faults carry more than half the fluid produced and reinjected, the useful

lifetime may be drastically shorter than predicted from porous-flow calculations.

A Fracture-Dominated System Like Raft River. If most of the flow is from fractures, then the correction factor depends only on the fracture spacing and the rate at which heat is removed from the system. In Fig. 5-26 we see that the dependence of the correction factor on pumping rate can be strong, and knowledge of the fracture spacing in such a system is crucial for planning exploitation rates.

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5.4.3 THERMAL HISTORY OF INJECTED EFFLUENTS

Liquid-dominated geothermal resources often contain fluid with a high concentration of dissolved solids. During power production, flashing and heat extraction can increase the effective concentration of solutes in geothermal fluids above saturation, resulting in scaling and the production of suspended solids. Methods have been developed to chemically modify brine from the Salton Sea Geothermal Field so that the supersaturated brine is stable long enough for thermal energy to be extracted and brine effluents injected (see Section 4.4). If effluents are reheated rapidly enough after injection into the reservoir, the brine may become undersaturated and not precipitate solids in porous rock penetrated by injection wells.

In order to determine the potential for formation damage from injection, it will be necessary to establish the following:

1. The kinetics of precipitation reactions in supersaturated brine at different temperatures and pH (see Section 4.5).
2. The extent and rate of possible brine-rock interactions (see Section 5.5).
3. The time constant for reheating of injected effluents.

Problem 3 is the subject of this discussion.

The thermal history of a particular particle of injected effluent is derived by using the following assumptions:

1. The fluid is injected at a constant volumetric flow rate Q into a layer of uniform permeability (k) of height H from a line source perforated through its entire length. Gravity is ignored so that the flow is radial.

2. The fluid moves away from the source without mixing. The flow from any time interval displaces the shell of fluid from previous intervals outward away from the source. Consequently, the flow rate through a small area A (normal to the flow) at a distance r from a well is $QA/2\pi rh$, and the flow rate per unit area decreases as $1/r$.

3. The fluid is assumed to flow in small pores in the rock matrix and to reach thermal equilibrium with the rock matrix in a negligible time. Consequently, only the thermal properties of saturated rock need be considered (i.e., temperature T_s and conductivity K_s). The saturated rock is initially at temperature T_0 , and the fluid is injected at temperature T_0 .

4. The compressibility and thermal expansion of the rock and fluid are ignored.

5. The parameters used for calculations are listed in Table 5-3.

Analytical Solutions for Radial Flow

Bodvarsson (1972) has solved this problem for linear flow and demonstrated that a very sharp thermal boundary separates regions of fluid with temperatures T_0 and T_i (Fig. 5-27). Temperature fronts move with a smaller velocity than do fluid fronts. The ratio of the temperature-front velocity to the particle velocity depends on the heat content of the fluid and of the rock. This result disagrees with most people's intuitive feeling that a large

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Table 5-3. Reservoir parameters chosen for calculations

Parameter	Old units	S.I. units
Flow rate Q	400,000 lb/hr at 62.4 lb/ft ³	0.0504 m ³ /sec
Permeability k	500 millidarcys	5×10^{-13} m ²
Thickness h	660 ft	200 m
Conductivity K_s	0.58 Btu/hr-ft ² -°F	3.29 W/m-K
Heat capacity C_R	0.256 Btu/lb-°F	1070 J/kg-K
Heat capacity C_F	1.0 Btu/lb-°F	4180 J/kg-K
Viscosity μ	0.2 cP	2×10^{-4} Pa-sec
Density ρ_f	62.4 lb/ft ³	1000 kg/m ³
Porosity ϕ	0.20	0.20
Density ρ_R	144 lb/ft ³	2300 kg/m ³

volume around the well should cool slowly. Because the result conflicts with our expectations, the equations are derived here for radial flow.

Consider an incremental volume dV of saturated rock with permeability ϕ and dimensions dr , $d\theta$, and dz , with flow velocity and temperature variations only in the r direction:

The heat conduction in the volume is given by

$$Q(r) = -K_S \frac{\partial T}{\partial r}.$$

The total heat content of the volume is

$$H(T) = [\rho_F C_F \phi + \rho_R C_R (1 - \phi)] T dV$$

where the density ρ and the specific heat C are given for both rock matrix and fluid. Heat is removed from the volume by mass flow and by conduction. The heat balance is

$$H(t + dt) - H(t) = \frac{\rho_F C_F Q \Delta t r d\theta dz}{2\pi r h} [T(r) - T(r + dr)] + \Delta t r d\theta dz [Q_H(r) - Q_H(r + dr)].$$

Using $dV = r d\theta dz dr$, dividing by $\Delta t dV$, and taking limits, we obtain

$$(\mu_F + \mu_R) \frac{dT}{dt} = -\frac{Q \mu_F}{2\pi r h \phi} \frac{\partial T}{\partial r} + K_S \frac{\partial^2 T}{\partial r^2}, \quad (5-8)$$

where

$$\mu_F = \rho_F C_F \phi$$

and

$$\mu_R = \rho_R C_R (1 - \phi).$$

This equation can be simplified by noting that the particle velocity V can be found from the volume of rock needed to hold the fluid that flows in time Δt :

$$V_p(r) = \frac{Q}{2\pi h \phi r} = \frac{a}{r},$$

where a is a constant.

Fig. 5-27. Cross section of permeable layer, showing temperature front at distance $r_T(t)$ from injection well. (After Bodvarsson, 1972.)

The solution of Eq. (5-8) is trivial if the second derivative is ignored. The conditions under which the conduction term can be ignored are discussed later.

$$\frac{dT}{dt} + \frac{V_p(r)}{R} \frac{\partial T}{\partial r} = 0, \quad (5-9)$$

where

$$R = \frac{\mu_F + \mu_R}{\mu_F} = 3.4.$$

Equation (5-9) is hyperbolic and is satisfied by any solution of the form

$$T(r, t) = f \left[\int \frac{R}{V_p(r)} dr - t \right].$$

For $V_p(r) = ar$, the solution has the form $f[(R/2a)r^2 - t]$.

The boundary condition for $r = 0$ (at the well) is

$$T(0, t) = \begin{cases} T_0 & \text{for } t \leq 0 \\ T_{inj} & \text{for } t > 0 \end{cases}$$

assuming that injection of cool fluid begins at $t = 0$. The uniform temperature (T_0) in the porous layer before injection starts is modeled by assuming that warm fluid is injected before $t = 0$. The solution has a sharp boundary between hot and cold fluid moving through the formation with velocity $V_p(r)/R$.

The time required for the front to cover any distance r from the well is given by

$$t_f(r) = \int_0^r \frac{R}{V_p(r)} dr = \frac{r^2}{2a} R.$$

If a particle is injected into the reservoir at time t_p , it moves out a distance r at time $t_p(r)$:

$$t_p(r) = t_p + \int_0^r \frac{1}{V_p(r)} dr = t_p + \frac{1}{R} t_f(r).$$

The particle remains cool until it crosses the temperature front; that is, when

Fig. 5-28. Location of temperature front and fluid particles injected at different times.

$$t_p(r) = t_f(r) \equiv t_c(r),$$

where

$$t_c(r) = t_p + \frac{1}{R} t_p,$$

$$t_c = \frac{R}{R-1} t_p.$$

The particle is cool in the rock for a time interval

$$t_c - t_p = \frac{1}{R-1} t_p = 0.4 t_p.$$

The period of time that a fluid particle remains cool within the reservoir is a substantial fraction of the time that the well has been used for injection (Fig. 5-28). For example, after a well has been used for injection for a year, the injected fluid will stay cool for 3 months. That result is independent of the permeability or thickness of the injection aquifer and also can be shown to apply for spherical or linear flow.

Other Factors

Conduction of Heat. The conduction term in Eq. (5-8) can be ignored if

$$\frac{K_S}{\mu_F + \mu_R} \frac{1}{L} \ll \frac{Q}{2\pi rh\phi} \frac{\mu_F}{\mu_F + \mu_R},$$

where L is the distance over which $\partial T/\partial r$ is non-zero. The inequality is satisfied if

$$L > 4 \times 10^{-3} r,$$

and the heat conduction term will cause a spreading of the temperature front over a distance less than $r/100$ and will thereafter be unimportant.

Density Differences and Gravity. The cool supersaturated effluent will be more dense than the virgin brine and consequently will displace brine from the bottom of the layer. The resulting flow will have a vertical component, which was ignored in the preceding discussion. The cooling front will be conical, rather than a vertical cylinder, but the total volume cooled at any time and the time it takes a particle to reach the front will not change.

Because the injected brine is more saline than the virgin brine, it will stay on the bottom even after it is heated. Consequently, the cooling front will not be distorted by convection.

Mixing. Bear (1972, Section 10.7.4) has analyzed the contribution to heat transport of mixing on a molecular scale and on a macroscopic scale. He concludes that transport on a molecular scale is always negligible and that heat transport due to

macroscopic mixing can be ignored if the Reynolds number ($Re = V_p d \rho_f / \mu$) is less than 3 (i.e., for laminar flow). For particle sizes on the order of 1 mm, that condition holds for distances greater than $r_t = 0.3$ m from the well. It is difficult to assess the effect that turbulence near the wellbore might have on the temperature distribution, but the worst effect it could have is to spread the cooling front out over a distance comparable to r_t . In the region of laminar flow, the front would propagate with no further distortion.

Summary

Fluid injected into porous rock will not be heated immediately, but will remain cool for approximately one-fourth of the time that the well has been used for injection. For any economically useful injection well, fluid will eventually remain cool for many years. Consequently, the long-term stability of supersaturated brine solutions should be established.

P. W. Kasameyer

5.4.4 EVALUATION OF INJECTION-WELL PERFORMANCE

The economic viability of geothermal power production at the Salton Sea Geothermal Field will require a long-term capability for injection of brine effluents. A key question that arises in considering the useful lifetime of an injection well is the period of time over which a given reservoir horizon will continue to accept fluids, since brine effluents may carry substantial loads of suspended solids that could plug casing perforations or cause formation damage. Even if effluents were relatively free of suspended solids, formation matrix properties (i.e., permeability, porosity) might still be altered either by delayed chemical reactions in the reservoir resulting in the precipitation of solids or by brine-rock chemical interactions.

The manner in which effluents alter the constitutive definition of shear in a porous medium as implied in Darcy's law is far from being understood. It would be useful, therefore, to consider a range of formation matrix properties (i.e., diffusivity laws) that not only change in time due to, say, the deposition of particulates but also vary as a function of radial distance from the wellbore and the injection rate history. Unfortunately, the problem is complex because there are many dif-

fusivity laws that could be derived to describe a reservoir's response to a particular injection history.

The first thing that needs to be done is to classify diffusivity laws in terms of phenomenology that can either be logically anticipated on the basis of previous field experience or tested by appropriate experiments. For instance, operational experience with long-term injection of brine effluents from the Magmamax No. 1 well into Magmamax No. 3 (see Section 5.4.5) and the results of preliminary laboratory core-flushing experiments (Section 5.5) have indicated that plugging of casing perforations and skin damage will be common modes of injection failure.

Having classified failure modes, it would then be useful to derive solutions for the appropriate diffusivity law in terms of the pressure response at the injector. If we were then given a set of field measurements (e.g., wellbore or wellhead pressures) for a particular injection regime, it would be relatively simple to deduce the applicable diffusivity law corresponding to the field observation so as to be able to then predict, from the model, future pressure distributions near the wellbore. In this way, it may be possible to detect initial damage

to the wellbore or formation sufficiently early for remedial action to be effective. The alternatives are less desirable: operation of the well to failure and possible permanent damage, resulting in abandonment.

Derivation of Diffusivity Laws

All of the subsequent analytical solutions are based on the following implicit assumptions: two-dimensional Darcy flow propagating from a line source through an unconfined isotropic medium with constant pressure at infinity. Mathematical notations are defined in Table 5-4.

Table 5-4. Notation

r	Radial distance from center of wellbore
t	Time elapsed after initial operation
P	Pressure in the matrix
κ	Material diffusivity, $\sim 10^{-5}$ kg/m-Pa-sec
P_{∞}	Pressure at the far edge of the reservoir
τ	Conveniently transformed time scale = $\int_0^t \kappa dt$, the time integral of the diffusivity
Q	Injection well flow rate, 0.04 m ³ /sec
T	Transmissivity, $\sim 10^{-6}$ m ³ /sec-Pa
C_0	Compressibility, 1.45×10^{-9} Pa ⁻¹
ρ	Density
μ	Viscosity, $\sim 2 \times 10^{-4}$ Pa-sec

Nondimensionalized coordinates

$$\bar{p} = p_{\infty} + \frac{Q}{2\pi\alpha_0 T} P, \quad \lim_{r \rightarrow 0} r\kappa p_r = \frac{Q}{2\pi T}$$

$$\sim 2.12 \times 10^4 \text{ m}^2\text{-Pa/sec}$$

$$\bar{\kappa} = \alpha_0 \kappa, \quad \alpha_0 \sim 10^{-5} \text{ kg/m-Pa-sec}$$

$$\bar{t} = t/\alpha_1, \quad \alpha_1^{-1} \sim 579 \text{ days}$$

$$r = \frac{\alpha_0}{\alpha_1 C_0} \bar{r}, \quad C_0 \sim 3.3 \times 10^{-6} \text{ kg/m}^3\text{-Pa}$$

$$r_b = \text{wellbore radius} = \frac{\alpha_0}{\alpha_1 C_0} (0.2 \text{ m}) \cong 1.67 \times 10^{-5}$$

Note: Quantities with a bar (e.g., $\bar{r}$) denote dimensional coordinates. Values from McKee and Shaw (personal communication, 1976).

Our objective is to understand how the behavior of any given geothermal well responds to changes in matrix diffusivity. As the physical processes in a working matrix are not well understood, the study concerns itself with a selection of diffusivities that vary in space and time according to various prescribed and seemingly reasonable laws. The porous flow equations for a Darcy flow are then solved to obtain the pressure for the various diffusivity laws. An interesting characteristic of the results for strictly time-dependent diffusivities is that sufficiently close to the wellbore

$$p(r,t) \simeq \frac{A \log r}{\kappa(t)},$$

where A is the net inflow into the matrix and p , κ , and r are the pressure, diffusivity, and radial distance from the wellbore, respectively.

In what follows, dimensionless coordinates are used. The nondimensionalizations used are given in Table 5-4. The general solution for any sufficiently smooth time-dependent diffusivity $\kappa(t)$ is given by

$$p(r,t) = \sum_{n=-\infty}^{+\infty} (B_n \tau^n) M\left(-n, 1, -\frac{r^2}{4\tau}\right) + \text{complementary function}, \quad (5-10)$$

where M is the confluent hypergeometric function, $\tau = \int_0^t \kappa(s) ds$, and the B_n terms are found by equating term by term with the implicit function

$$C(\tau) = \frac{1}{\kappa(t)} = \sum_{n=-\infty}^{+\infty} D_n \tau^n = \frac{1}{A} \lim_{r \rightarrow 0} (r p_r).$$

To illustrate the result for

$$\kappa = \frac{\alpha_0}{(1 + \alpha_1 t)^N},$$

α_0 and α_1 are absorbed in the nondimensionalization, and for $N = 1/2$,

$$p(r,t) = \frac{1}{2} \sigma \exp\left(-\frac{r^2}{8\sigma}\right) + \frac{1}{2} \left[1 - \sigma \left(1 + \frac{r^2}{8\sigma}\right)\right] E_1\left(\frac{r^2}{8\sigma}\right),$$

where $\sigma = (1 + t)^{1/2} - 1$.

For $N = 2/3$,

$$p(r, t) = \frac{\tau}{3} \left[1 + \frac{\tau}{24} \left(2 - \frac{r^2}{4\tau} \right) \right] \exp \left(-\frac{r^2}{4\tau} \right) + \frac{1}{2} \left[1 - \frac{2\tau}{3} \left(1 + \frac{r^2}{4\tau} \right) - \frac{\tau^2}{9} \left(1 + \frac{3r^2}{8\tau} + \frac{r^4}{64\tau^2} \right) \right] \left[E_1 \left(\frac{r^2}{4\tau} \right) \right],$$

where $\tau = 3(1 + t)^{1/3} - 3$. Figures 5-29 and 5-30 are plots of the diffusivity and the pressure at the wellbore, respectively, as a function of time.

Even though some serious constitutive problems may arise in using Darcy's law with a radially dependent diffusivity, clearly Eq. (5-10) must be generalized to materials whose diffusivity varies not only with distance from the wellbore but also with pressure and the flow history of the region. For example, the rate of particulate deposition probably depends on how much clogging has already occurred (i.e., pore size). To model such phenomena we require a diffusivity that varies as the time integral of the flow in the matrix. Diffusivity laws of the form $\kappa(r, t) = \alpha(t) \beta(z)$, $z = r/\sqrt{t}$ are currently being studied. Some examples that indicate the trend of the results are the cases where

$$\kappa(r, t) = 1 - \frac{\rho}{z^2} = 1 - \frac{\rho t}{r^2} \quad (\rho \ll 1)$$

(see Fig. 5-31). The solution is

$$p(r, t) = \frac{C_0}{2} (4\rho e)^{-\rho/4} \Gamma \left[-\frac{\rho}{4}, \frac{1}{4} \left(\frac{r^2}{t} - \rho \right) \right],$$

where Γ denotes the incomplete gamma function. Further generalizations are possible, and we are currently evaluating them.

One final type of material diffusivity has been considered that yields a nonlinear differential

Fig. 5-29. Plot of diffusivity $\kappa(t)$ versus time $\bar{t}$. The value of α was picked to obtain a 5% drop in diffusivity in 3 months for $N=1$.

Fig. 5-30. Plot of pressure $p(r_b, \bar{t})$ versus time $\bar{t}$ for radius $r_b = 1.67 \times 10^{-5}$.

equation. When $\kappa = m(p, \Delta p)$, we can no longer use the linearity of the operator. An example is $\kappa = B + (1/h')$, where $h(z) = p(r, t)$ and the prime denotes d/dz for $z = r/\sqrt{t}$. If we consider a constant pressure at $z = 0$ rather than a constant pressure gradient, then

$$p(r, t) = C_0 + \frac{\sqrt{2}}{B} \operatorname{erf} \frac{r}{\sqrt{2Bt}},$$

where erf is the error function. Tabulations for the various functions are available.

The aim here is to build up a sufficient understanding of the dependence of the pressure on the varying material diffusivity to permit determination of the diffusivity from field measurements of the pressure. Experience to date with an injection well, Magmamax No. 3, and results of laboratory core-flushing experiments indicate that two types of diffusivity-limiting processes operate adjacent to the wellbore:

1. A relatively rapid process involving skin damage and clogging of perforations can be simulated as shown in Fig. 5-31.
2. A relatively slow process involving uniform decay of diffusivity throughout the matrix can be simulated as shown in Fig. 5-29.

Fig. 5-31. Plot of diffusivity versus distance from the wellbore for several times.

Since the type of differential equation for these processes is linear, it is possible to transform out the time dependence of the diffusivity and treat any combination of matrix variabilities.

H. A. Sklar

5.4.5 RESERVOIR EVALUATION

Pressure-Transient Analysis

The principal objective of pressure-transient analysis is the determination of a reservoir's transmissivity T , a lumped parameter that describes the overall flow characteristics of the reservoir and reservoir fluid:

$$T = \frac{kb}{\mu},$$

where k is permeability, b is reservoir thickness, and μ is viscosity. If μ and b are known and wellhead or wellbore pressures can be monitored during appropriate tests, k can be calculated. Commonly employed notation is summarized in Table 5-5.

Two basic types of transient measurements can be made. The pressure or hydraulic head as a function of time in the perturbed well (production or injection) can be measured, and the pressure or head

in an observation well due to production and/or injection in other wells can be measured. The value of T calculated from pressure transients in the perturbed well gives an areal average of the T value for the formation within the radius of influence of the production or injection well. The value of T calculated from pressure transients in an observation well gives the average T value of the formation between the observation well and the perturbed well. In certain cases simultaneous measurements in several observation wells can determine anisotropy, direction of principal permeability, and vertical permeability in a multilayered system.

In addition to transmissivity, several other parameters can be determined from well testing: storativity of the formation, well efficiency, and skin effect. Caution should be exercised in calculating these parameters, particularly if the pressure transients measured are in the perturbed well. Experience has shown that calculations of storativity using the radius of the wellbore in the solution

Table 5-5. Notation

Symbol	Variable	Unit	Dimensions
T	Transmissivity	ft ² /day	L^2/T
T	Transmissibility	md-ft /cP	L^4T/M
γ	Specific weight	lb/ft ³	M/L^2T^2
k	Permeability	millidarcys	L^2
b	Thickness of formation	ft	L
μ	Viscosity	cP	M/LT
p	Pressure	psi	M/LT^2
h	Hydraulic head	ft	L
t	Time	(normally minutes)	
U	Arbitrary variable		
$Ei(-U)$	Exponential integral		
r	Radius from well	ft	L
ϕ	Porosity, dimensionless		
c	Compressibility		LT^2/M
Q	Flow rate	lb/hr or barrels/day	L^3/T
S	Storage coefficient, dimensionless		
B	Formation volume factor, dimensionless		
kb	Injective capacity	md-ft	L^3

can produce significantly erroneous values for storativity. Similar difficulties are experienced in calculations of well efficiency and skin effect from perturbed-well measurements alone.

Recording of pressure transients in a perturbed well is usually referred to as drawdown or buildup testing; recording of pressure transients in an observation well is usually referred to as interference testing. Pulse testing is a form of interference testing in which nonsignificant pressure transients are filtered out by cyclically perturbing the reservoir system and superposing of solutions.

Techniques for calculating parameters from well testing are based on analytical solutions to the diffusion equation. The most frequently used solution is based on the following assumptions: (1) the formation is uniformly thick, homogeneous, isotropic, and radially infinite; (2) the well is a line sink/source and fully penetrates the formation; (3) fluid released or injected is due to the expansion or compression of the formation and the formation fluid; and (4) there are no vertical gradients (radial flow). The diffusion equation for flow through porous media takes the following form:

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{\phi \mu c}{6.328k} \frac{\partial p}{\partial t}$$

or

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r} \frac{\partial h}{\partial r} = \frac{s}{T} \frac{\partial h}{\partial t}$$

Solutions for the diffusion equation for pressure or hydraulic head as a function of time take the form of an exponential integral:

$$p(t) = p_0 - \frac{70.6QB\mu}{kb} [-Ei(-U)] ,$$

where

$$U = + \frac{948.2r^2 \phi \mu c}{kt} .$$

Two basic techniques are used to calculate T from the above solutions: the semilog-slope approximation and the log-log curve-matching procedure. In the semilog-slope method, pressure p or head h is plotted as a function of log of time t from start of test. The slope m of the straight-line portion of the graph is then related to T by

$$T = \frac{2.3Q}{4\pi m} .$$

The storage coefficient S can also be calculated by using an equation of the form

$$S = \frac{2.25t_0}{r^2}$$

In the log-log curve-matching procedure, a "type" curve of $\log_{10} [Ei(-U)]$ as a function of $\log_{10} U$ is matched with a plot of $\log_{10} p$ or $\log_{10} h$ as a function of $\log_{10} t$. A match point such as where $Ei(-U) = 1$ and $U = 1$ is chosen, and the corresponding coordinates on the $\log_{10} h$ versus $\log_{10} t$ plot are used to solve for T and S :

$$T = \frac{Q}{4\pi(h_0 - h)},$$

$$S = \frac{4Tt}{r^2}$$

If sufficient data are available, the curve-matching technique will give a more accurate estimate of the formation parameters than does the semilog approach.

Additional analytical solutions and techniques are available to handle more complex boundary conditions such as partial penetration of the formation by the well, multilayered systems with leakage (vertical permeability), recharge and barrier boundaries, and anisotropy. These techniques can greatly improve parameter estimates of the more complex formations often encountered in the field. However, determination of which analytical methods to use is a function of the quality of the data and *a priori* knowledge of the reservoir system. As data from field tests become available, it becomes easier to choose the most appropriate technique to update and improve estimates of reservoir flow parameters and reservoir geometry.

J. G. Morse

Well Testing

A reservoir testing plan for the Salton Sea Geothermal Field has been developed and is now being carried out. Initially, emphasis will be placed on testing the southwestern part of the field since this area has the only presently operating geother-

mal wells; operation of the ERDA/San Diego Gas & Electric Company Geothermal Loop Experimental Facility (GLEF) is supported by production from the Magmamax No. 1 and Woolsey No. 1 wells, with injection into Magmamax No. 3 (see Fig. 5-1). A second injection well, Magmamax No. 2, is also available, as is a relatively shallow (2550 ft) observation well, Magmamax No. 4, located about 50 yards west of Magmamax No. 3. Two other wells, Elmore No. 1 and Sinclair No. 3, located about 1.5 miles to the north and 1 mile to the south of Woolsey No. 1, respectively, are shut in but are potentially available as static pressure monitoring points.

Equipment. Sperry-Sun pressure monitoring equipment and an ultrasensitive Hewlett-Packard quartz-crystal pressure-sensing system have been obtained. Corrosion-resistant Hastelloy C-276 downhole pressure tubing for use with the Sperry sondes has also been ordered but will probably not be available until late Summer 1977. Tubing lengths of 1000 and 4000 ft each will permit pressure monitoring of two wells simultaneously. In the interim, the Magma Power Company has agreed to lend us lengths of its own Ebrite tubing. It has also agreed to supply the necessary field support to lower and recover devices from wells.

Injection Tests. Injection pressures will be monitored on a continuous basis with the Sperry-Sun equipment. A record of injection-well performance as a function of plant operating loads will be helpful in evaluating wellbore or formation damage induced by the injection of suspended-solids-loaded effluents. These data will also be helpful in evaluating our analytical models of injection-well performance (Section 5.4.4) and the results of core-flushing experiments (Section 5.5).

Whenever an injection well is shut in, a pressure dropoff can be obtained; if a Sperry sonde is lowered through a wellhead lubricator prior to shut-in, the dropoff survey can be carried out with improved accuracy as compared to data routinely obtained with a Kuster bomb. For continuous pressure monitoring, a Sperry-Sun pressure recorder can be linked directly to the surface injection line via a silicone oil interface. An advantage of this arrangement is that buildup surveys can be carried out without subjecting the system to the rapid temperature fluctuations that would normally be experienced during initial startup by a pressure sonde suspended in the wellbore. Analysis of the buildup and dropoff pressure response will yield average

hydraulic properties of the formation adjacent to the wellbore.

Pulse and Interference Tests. Concurrent with injection tests, a series of modified pulse-interference tests are also planned. The results of this effort will provide sufficient data to characterize the average hydraulic properties of the reservoir between the production and injection wells. The execution of these tests will require cyclical operation of the production wells at full- and half-flow capacity, followed by long-term operation at full-flow capacity with injection of all effluents.

Most existing solutions for interference tests assume a confined, single-layered system that is fully penetrated by the well. Solutions also require a uniformity of fluid properties. The geothermal reservoir at the GLEF site is complex and appears to be a two-aquifer system separated by a major shale break. Properties of the produced and injected fluids such as temperature, density, and viscosity may differ significantly. The wells at the GLEF site are partially penetrating, and leakage may be occurring through the shale break and past the well casing. With these limitations to the various existing solution techniques in mind, a best interpretation of the data will be made. Additional analytical and numerical solution techniques will be developed and applied to the Niland reservoir as necessary.

Present estimates of the permeability of the reservoir range from 100 to 300 millidarcys (Schroeder, 1976). Using these estimates, the calculated minimum response at Magmamax No. 1 to a flow of 400,000 lb/hr at Woolsey No. 1 should be 1.0 psi. A minimum response at Magmamax No. 1 to the injection of spent brine in Magmamax No. 3 is 0.5 psi. This transient pressure response will be easily measured by the Hewlett-Packard equipment, which has a sensitivity of 0.01 psi. During the testing sequence, the feasibility of measuring pressure transients in observation wells with a steel tape can also be evaluated. Steel-tape techniques have been used in water-well studies for years with a consistent accuracy of 0.01 ft, which translates to a pressure change of 0.005 psi. If the surfaces of the columns are sufficiently quiet, then the technique should work.

Corrosion Tests. The Sperry-Sun sonde must be in a well at least 2 days prior to the start of a dropoff survey to permit adequate thermal equilibrium of the pressure transmission system. Previous experience by Magma Power indicated that the Ebrite pressure tubing has a maximum continuous ex-

posure lifetime of about 6 weeks. Hastelloy C-276 should perform better, but this material will not be available for several months. In cooperation with the materials evaluation effort, we have suggested that corrosion specimens be fitted to the Sperry-Sun sonde in the form of thin, tightly wrapped, electrically insulated bands. Since it appears feasible and safe to support the sonde in an injection well with Ebrite tubing for 1-week periods, it should be possible to carry out dropoff surveys and corrosion screening tests simultaneously.

J. G. Morse

Case Studies: Drillstem Tests

Drillstem test (DST) records for two wells (Magmamax No. 1 and Woolsey No. 1) supporting operation of the GLEF have been analyzed (Schroeder, 1976). The subsurface geology of the test site has been discussed in Section 5.2. Important subsurface characteristics of the site are summarized in Fig. 5-32. Completion data for geothermal wells on the GLEF test site are shown in Fig. 5-33.

Three DSTs were recorded per well. The tests were carried out immediately after drilling operations were completed. All of the tests indicated equalization after a few minutes of flow, suggesting relatively high formation permeability and storage.

Magmamax No. 1. For the Magmamax No. 1 well, three DSTs were recorded during drilling, but only the first DST record allowed quantitative analysis for transmissivity. In the remaining two tests, equalization occurred so fast that such analysis was not possible. The first DST sampled an 8-ft interval of the lower reservoir adjacent to the bottom of the shale break.

The 30-min drawdown of DST No. 1 was analyzed by determining the time-dependent flow rate during fillup of the drillstem, and then a multi-rate analysis was used to obtain transmissivity. Neglecting frictional losses and wellbore heat losses, the time-dependent mass flow rate is given by

$$\frac{ds}{dt} = \rho g \frac{dz}{dt} = \frac{g}{A} (q - q_s),$$

where q_s is the mass flow rate of the steam, q is the total mass flow rate, A is the drillstem's cross-sectional area, z is the height of the column of liquid, s is the head, and, using x as the steam quality,

Fig. 5-32. Well-log resistivity analysis at the Magma/SDG&E geothermal test site. The wells are shown in oblique projection (horizontal and vertical dimensions are true). Jagged lines along wells give the percentage of sandstone at that depth. Tick marks to left of wellbore indicate depth in 1000-ft intervals. (Information from D. Towse, January 5, 1976.)

$$q(t) = \frac{A}{g[1-x(t)]} \frac{ds(t)}{dt}$$

$$\approx \frac{A}{g} \left[\frac{1}{(1-x)} \frac{\Delta s}{\Delta t} \right]$$

The superposition principle (Matthews and Russell, 1967) gives the transmissivity for a multi-rate analysis as

$$\frac{kb}{\mu} = \frac{1}{(2\pi\rho)} \frac{\sum_{i=1}^N \left[(q_i - q_{i-1}) P_D(1, t_{Di} - t_{Di-1}) \right]}{(P_{\text{initial}} - P_{r_w, t_{DN}})}$$

The flow interval is b , the well radius is r_w , and p_D is the dimensionless drawdown function. The in-

itial mass flow rate is defined as $q_0 = 0$, and the dimensionless time is

$$t_D = \frac{\lambda t}{r^2},$$

where λ is the diffusivity:

$$\lambda = \frac{k}{\phi\mu B}$$

In these equations, P_{initial} is the initial hydrostatic pressure (Pa); $P_{r_w, t_{DN}}$ is the pressure at radius r_w at time t_{DN} ; ϕ is the porosity; μ is the viscosity (Pa-sec); and β is the compressibility (Pa^{-1}).

If P_D corresponds to a line source in an infinite reservoir, the dimensionless pressure drop P_D can be approximated by

$$P_D \left(\frac{r}{r_w}, t_D \right) = \frac{1}{2} \ln \left(\frac{4\lambda t}{\gamma r^2} \right),$$

where $\gamma \approx 1.78$ is Euler's constant (Meidav and Furgerson, 1972). The appropriate values of these parameters, obtained from the first DST in the Magmamax No. 1 well, are given in Table 5-6.

The permeability stabilizes at about 160 millidarcys. The corresponding transmissivity is about $3.25 \times 10^{-13} \text{ (m}^3/\text{sec)Pa}$. The assumed value for permeability used in calculating the diffusivity of about 160 millidarcys was obtained by iterating until the permeability resulting from the drawdown analysis agreed with the assumed permeability in the diffusivity.

Woolsey No. 1. Two DSTs were analyzed by the method outlined above for Magmamax No. 1. A third test was run, but equalization occurred too rapidly for subsequent analysis.

Successful DSTs were carried out in the lower and upper reservoirs adjacent to the shale break. Parameters used for the calculations were identical with those listed in Table 5-6 except for the

iteratively determined values of permeability (247 and 177 millidarcys).

The validity of the multirate drillstem analysis was checked by the curve-matching technique developed by Ramey et al. (1975). All of the pressure transients recorded during the DSTs responded as slug tests. This method permitted analysis of five of the six available DSTs. The results are shown in Table 5-7, which includes the results of the multirate analysis for comparison.

The results in Table 5-7 show the permeabilities above and below the shale break to be of the same order of magnitude. Permeabilities on either side of the shale break have the lowest values (DST 2 and DST 3 in Woolsey No. 1). The relative magnitude of the calculated permeabilities seems to correlate with sand percentages for various depths obtained from well logs.

Caution should be exercised in extrapolating the results of these tests to the overall reservoir system. The drillstem tests were of short duration, produced relatively small amounts of reservoir fluid, and had a resulting small radius of influence. Each test sampled only a small (6 to 8 ft) interval of a large (3000 to 4000 ft) and highly permeable formation. Furthermore, the downhole Bourdon-type

Fig. 5-33. Completion data for geothermal wells at the GLEF site. The numbers on the right of each diagram are the depth in feet. The numbers on the left of each diagram are the casing diameters in inches. The heavy arrow is the depth of the correlation point for the shale break separating the upper and lower reservoirs. The heavy line indicates the location of the perforations. All data are believed to be current up to January 1977, when Woolsey No. 1 was redrilled to about 3400 ft.

Table 5-6. Estimated parameters for interpreting DST No. 1 in the Magmamax No. 1 well

Symbol	Metric units		English units	
	Value	Units	Value	Units
r_w	0.028575	m	2.25	in.
ϕ	0.2			
μ	1.2×10^{-4}	Pa-sec	0.12	cP
β	6.2×10^{-10}	Pa ⁻¹	4.4×10^{-6}	psi
ρ	1000	kg/m ³		
h	2.43	m	8	ft
k_{assumed}	1.6×10^{-18}	m ²	160	md

Table 5-7. Drillstem data analysis by the curve-matching technique

Well	DST Number	Depth interval (ft)	Permeability (md)	
			Curve matching	Multirate analysis
Magmamax No. 1	2	1854-1862	—	—
	3	1862-1870	175	—
	1	2556-2564	121	160
Woolsey No. 1	1	1227-1233	113	—
	2	1907-1913	81	247
	3	2313-2319	82	177

pressure gauge used in the tests is a relatively inaccurate device that provides poor early time data and is unresponsive to small pressure transients at late times.

To properly test the reservoir for its areal flow properties of transmissivity and storage, a series of buildup and interference tests is planned. One of the production wells, Woolsey No. 1, has been deepened and now has a 1000-ft slotted liner in the lower reservoir. Tests conducted with either Magmamax No. 1 or Woolsey No. 1 as the production well should provide more refined estimates of the areal transmissivity and storage coefficient for the reservoir with a minimum of partial penetration effects. These refined estimates of reservoir properties are essential if an analysis of the effects and possibilities of large-scale geothermal production is to be made.

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Case Studies: Injection Tests

Magmamax No. 3 is the primary injection well receiving effluents from the LLL Field Laboratory and the GLEF. Dropoff surveys were conducted by the Magma Power Company on December 14, 1976, and again on March 3, 1977. The last test was executed after injection pressure requirements exceeded available pumping capacity. Transmissivity was computed from the Magma Power data by the semilog-slope approximation:

$$T = 162.6 Q/m,$$

where m is the slope in units of psig per log cycle of dimensionless time and Q is the flow rate.

The analysis of this type of test is complicated by compressive and falling-head wellbore storage effects. For both tests, the correct straight-line portion of the semilog plot of pressure versus time was not reached until late in the test. By the time linear

response was observed, the pressure-transient response from the production well became significant, making an interpretation of the semilog plot difficult.

To obtain usable pressure-transient data from the injection well, both dropoff and pressure buildup surveys should be run. In buildup surveys, compressive wellbore storage effects dominate and the linear response of the well begins earlier in the test. Therefore more data, over a longer time interval, are available for analysis.

With these limitations in mind, the dropoff surveys for Magmamax No. 3 were analyzed. The results are summarized in Table 5-8.

Interpretation and Conclusions. The calculated injective capacity (kb) from the two surveys is of the same order of magnitude. Considering the relatively low precision, accuracy, and reliability of the Kuster device used to monitor pressure, the twofold difference in the apparent kb value should not be considered significant. The results are somewhat anomalous in that they seem to show an increase in injective capacity from December 14, 1976, to March 3, 1977, whereas operating conditions in the field indicate a decrease. The major problem in the analysis is that the field situation does not match the model used to derive the analytical solution. Furthermore, the solution technique is itself an approximation of the analytical solution.

The model assumes a confined, single-layered system that is homogeneous and fully penetrated by the well. In addition, the wellbore is treated as a line source, implying no effects due to wellbore storage or restrictions to flow in the wellbore. The geothermal reservoir underlying the GLEF site is a complex multilayered system consisting of two confined formations separated by a shale break that may be leaky. Magmamax No. 3 appears to be open only to the lower reservoir but is partially penetrat-

ing. The original perforations were in the lower 500 ft of the well, but the formation is more than 3000 ft thick. Complicating the field situation is uncertainty as to what portion of the 500 ft of perforations is actually open. A spinner survey taken before the March 3, 1977, dropoff survey indicated that fluid was entering the formation through only a 4-ft interval of the perforated casing. A correlation with geophysical logs indicates that this 4-ft interval is adjacent to a zone of relatively low permeability. This suggests that brine is channeling up and down the casing and out into the formation. The result of these complications is a large uncertainty as to the real value of b in the analysis. This in turn makes calculation of k nonunique.

Some useful comparison can be made with the survey data if results are compared with earlier estimates of formation permeability, which range from 100 to 1000 millidarcys (Schroeder, 1976). If we use a b value of 400 ft as the usable length of open perforations for Magmamax No. 3, the theoretical injectivity of the well should be from 40,000 to 400,000 md-ft. This capacity is an order of magnitude greater than that obtained from the dropoff surveys.

The difference in the calculated injective capacity kb may in part represent errors inherent in using a solution technique that assumes an ideal reservoir when in fact we are dealing with a more complex geometry. On the other hand, if it is assumed that the permeability of the formation has not been changed significantly by the injection of brine effluents, then discrepancies in calculated values for kb can be conceptually attributed to loss of effective formation thickness. The results of the spinner survey favor the latter possibility, loss of injectivity results primarily from deposition of suspended solids in casing perforations. However, deposition in the formation adjacent to the wellbore cannot be entirely discounted.

After the last dropoff survey in March 1977, the Magma Power Company cleaned the casing per-

Table 5-8. Dropoff survey results for Magmamax No. 3.

December 14, 1976	March 3, 1977
$kb = 5426$ md-ft	$kb = 10,618$ md-ft
$Q = 13,350$ B/D	$Q = 13,350$ B/D
$m = 360$ psi/cycle	$m = 184$ psi/cycle
$\mu = 0.9$ cP	$\mu = 0.9$ cP

forations, employing high-pressure water jets and chemical treatment (caustic leaching). As a result of this workover, injection pressures for flow rates of about 350,000 lb/hr returned to "normal" values, indicating that the failure was primarily due to the clogging of perforations.

Hydraulic Fracturing of Injection Wells

Freshwater injection tests were carried out on Magmamax No. 2 and No. 3 immediately after well completion. Magmamax No. 2 is completed, with perforations in the lower reservoir; Magmamax No. 3 is completed, with perforations probably just below the shale layer separating the upper and lower reservoirs, as shown in Fig. 5-33.

The initial injection tests in these two Magmamax injection wells indicate that hydraulic fracturing probably occurred during the tests. In Fig. 5-34 the peak downhole pressure at the midpoint of the perforations for Magmamax No. 2 and No. 3 is shown on the plot of bottomhole fracturing pressure versus depth. The injection tests show an initial high pressure with a low flow rate. The pressure then decreases as the rate increases quite suddenly. The subsequent pressure and rate are con-

Fig. 5-34. Theoretically predicted bottomhole fracturing pressures and field data (Perkins and Kern, 1961). The experimental peak downhole pressures for the Magmamax wells are shown by the open circles.

stant thereafter to the end of the test. These injection tests were carried out in 1972, and the fractures created at that time may have "healed."

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5.5 Injection Studies

Preliminary laboratory core-flushing experiments were conducted to evaluate the potential for permeability and porosity losses induced by the injection of expanded brine effluents with suspended solids. These experiments involved the passage of untreated and unfiltered brine effluents from the Magmamax No. 1 well through sedimen-

tary media under ambient temperatures and differential pressures of approximately 35 MPa. The brine was originally collected in a plastic-lined drum and stored for several weeks prior to use. Suspended solids consisted of colloidal silica with iron oxides and minor quantities of heavy-metal sulfides.

5.5.1 RESULTS

Right circular cylinders of sandstone were exposed to brine in the core-flushing apparatus shown in Fig. 5-35. The results of a typical run are shown in Fig. 5-36 for St. Peter sandstone, a silica-cemented rock with a nominal porosity of 15% and a pore diameter of approximately 50 to 100 μm . Flow rates through the core were reduced by about 80%

after the passage of 1500 pore volumes of brine. The squares in Fig. 5-36 represent the intrinsic flow rate through the core; the circles represent flow perturbations induced by the deposition of solids at the

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Fig. 5-35. Laboratory core-flushing apparatus.

upstream core-brine interface. It was necessary to interrupt the experiment periodically to remove these deposits, which were mixtures of silica, iron oxides, and metal sulfides. Similar deposits have fouled the Magmamax No. 3 injection well, necessitating periodic workovers (see Section 5.4.5). Absolute permeabilities were not calculated because viscosity data for hypersaline mixed-chloride brines are not available.

5.5.2 FAILURE MODES

Laboratory experiments indicate that injectors flowing solids-laden effluents may fail initially due to the plugging of perforations and the deposition of solids immediately behind the casing. This type of damage will be indicated by a rather rapid increase in the pressure necessary to maintain a desired rate of injection. Simultaneously, finer particles (i.e., colloids), if present in effluents, will deposit in the formation in intergranular pore space

Fig. 5-36. Typical results of laboratory core-flushing experiments for St. Peter sandstone.

Changes in intrinsic flow rate were indicative of permeability decline induced by the deposition of small particles in pores. The typical pore structure of St. Peter sandstone before and after exposure to brine was characterized by scanning electron microscopy (Figs. 5-37 and 5-38). These studies indicated that pores were clogged by colloidal iron oxides and/or hydroxides. Silica particulates were apparently effectively removed from the brine and deposited at the core-brine interface. This is not surprising in view of the oxidation of the brine, by exposure to the atmosphere, before the start of the experiment. Ferric hydroxide and silica coprecipitated as flocculent masses which were readily retained at the core-brine interface. Residual colloidal iron species passed through the interface region but subsequently deposited in pores (Fig. 5-39).

and fractures. These processes will probably occur at a much lower rate and will therefore be characterized by a slower rate of pressure increase for a given injection rate. Thus this type of formation damage will be more difficult to detect initially. Analytical solutions for these failure modes are discussed in Section 5.4.4.

It should be emphasized that the actual permeability laws describing a particular failure mode

Fig. 5-37. Scanning electron micrographs of St. Peter sandstone before and after exposure to brine effluents. (a) Two large pores (black) and surrounding grain structure of virgin St. Peter sandstone. (b) Exit of core after exposure to brine. Quartz grains are coated with deposits from brine. Pore diameter has been only slightly reduced. (c) Inlet region of core sample after exposure to brine. Pore diameter has been significantly reduced by the deposition of colloidal particles.

are dependent on the concentration, composition, and size distribution of suspended solids as well as the nature of reservoir permeability (i.e., fractures, intergranular pore space, or some combination of the two). Furthermore, the extent to which delayed chemical reactions in the reservoir (e.g., precipita-

tion and brine-rock interactions) might degrade the long-term performance of injection wells must also be considered. Although the core-flushing experiments are not definitive, they do provide qualitative data bearing on the potential for formation damage caused by the injection of a given effluent.

5.5.3 FIELD EXPERIMENTS

Future activities will involve field evaluations of the potential for mechanical and chemical plugging of reservoir rocks by the injection of low-temperature effluents. A core-flushing apparatus has been designed for this purpose and is now being

fabricated (Fig. 5-40). Core samples will be exposed to effluents from the LLL test bed so that permeability changes can be evaluated as a function of brine pH over the pH range from 2.0 to 6.0. A second apparatus will be located at the Magmamax

Fig. 5-38. Scanning electron micrographs of solids deposited from brine in pore space of St. Peter sandstone. Note reduction in pore diameters.

Fig. 5-39. High-magnification scanning electron micrograph of colloidal particles deposited from brine in the pores of St. Peter sandstone. Energy-dispersive x-ray analysis indicated that the colloidal particles are iron oxides.

Fig. 5-40. Core-flushing apparatus.

No. 3 wellhead, where the potential for well change induced by the injection of effluents from the GLEF can also be established.

Perhaps the most critical component of the field experiment is the specimen whose permeability is to be monitored. At present, there are no available core samples of producing sands from the Salton Sea Geothermal Field suitable for these experiments. As an expedient, well-characterized sandstones, with a porosity range of 15 to 31%, have been selected for the initial experiments (Table 5-9). Sandstone cores from the Dunes anomaly, located about 45 miles southeast of the Salton Sea Geothermal Field, are available and should be fairly typical of the high-temperature aquifers in the Salton Trough. Each sample, when exposed to brine, will be under a confining pressure of approximately 350 kPa to prevent channeling. The viscosity of brine effluents will be measured with a Brookfield LVF viscometer over the temperature interval from 25 to 95°C. Thus it will be possible to calculate changes in the absolute permeability of core samples during exposure to brine.

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