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Salton Sea

SCIENTIFIC DRILLING PROGRAM

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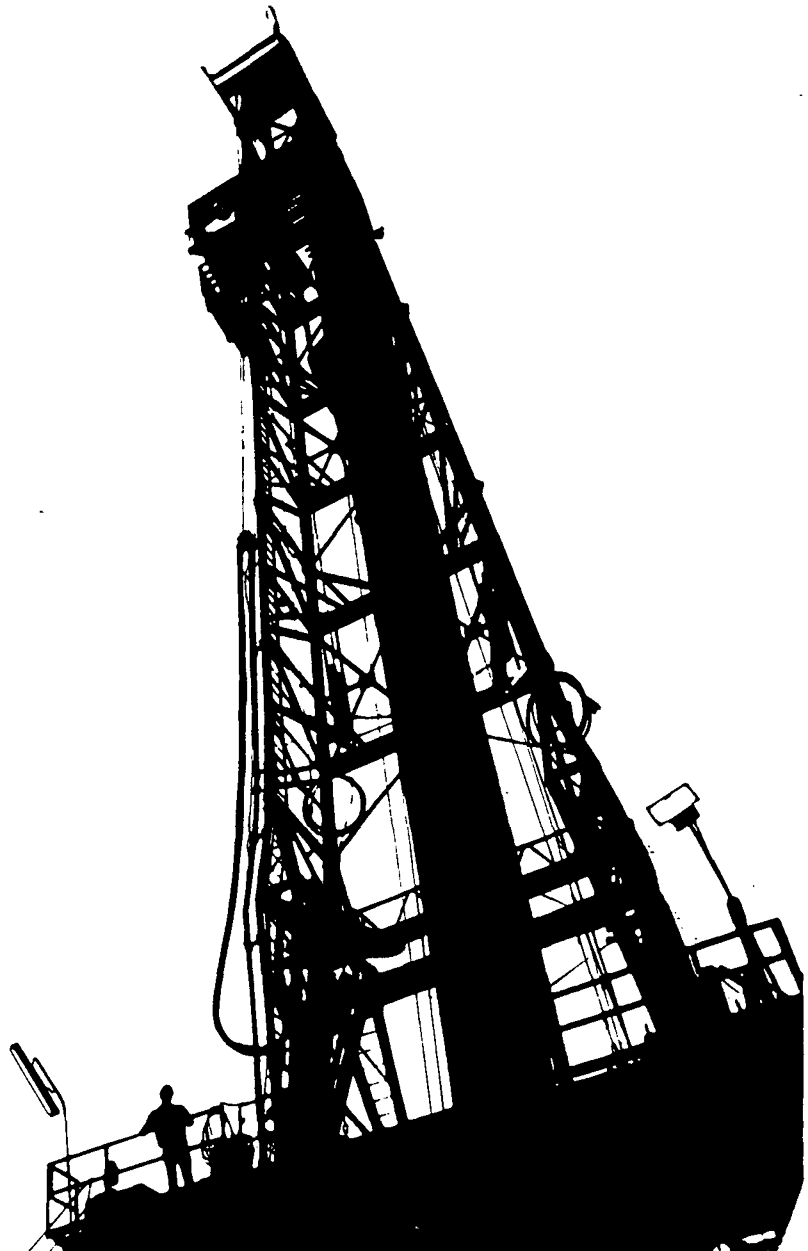

Phase 2

WELL REWORK AND FLOW TESTING

FINAL REPORT

SEPTEMBER 1988

WORK PERFORMED UNDER CONTRACT DE-AC-03-84-SF12194

by

BECHTEL NATIONAL, INC.

SALTON SEA SCIENTIFIC DRILLING PROGRAM
Phase 2--Well Rework and Flow Testing
Final Report

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Abstract

This report covers the activities of the Salton Sea Scientific Drilling Program from August 1986 to August 1988. The Phase 1 report covers the activities from project inception in the Fall of 1984 through the drilling and completion in April 1986 to the conclusion of the first rework operation in August 1986. This Phase 2 report includes well rework in August 1987, construction of a flow test facility, a flow test in June 1988, and cleanup of the site. The flow test in June 1988 showed that the well has high productivity and is capable of flow rates greater than 800,000 lbm/hr (363,000 kg/hr) at 250 psig (1,724 kPa) wellhead pressure; at this flow rate it could produce 12 MWe in a dual-flash power plant. Total dissolved solids of the preflash brine is about 250,000 mg/kg.

Section 1

INTRODUCTION

The Salton Sea Scientific Drilling Program (SSSDP) was the first major project performed under the Interagency Accord on Continental Scientific Drilling, involving the U.S. Department of Energy (DOE), the U.S. Geological Survey (USGS), and the National Science Foundation (NSF).

The final report for the SSSDP is divided into two parts:

- Phase 1. The well design and drilling are reported in "Salton Sea Scientific Drilling Program, Drilling and Engineering Program, Final Report," Volumes 1 and 2, which cover the activities from project inception in the Fall of 1984 through the drilling and completion at 10,564 ft (3,220 m) in March 1986 to the conclusion of the first rework operation in August 1986.
- Phase 2. This second report covers the activities from August 1986 to site cleanup in August 1988. These activities include rework of the well in August 1987, construction of flow test facilities, completion of a flow test of the well in June 1988, and cleanup of the site and abandonment of equipment in place.

1.1 PURPOSE AND OBJECTIVES

The primary objectives of the project were to:

- Explore the roots of the Salton Sea Geothermal Field by drilling into a deeper, hotter part of the system than had previously been probed
- Collect and place in the public domain samples and data, including core, cuttings, geothermal fluids and gases, and geophysical logs such as temperature and pressure surveys

As the prime contractor, Bechtel National, Inc., in association with Kennecott Corporation, was responsible for overall project management. Bechtel's responsibilities included planning, design and drilling of the well, provision of surface facilities and site support, environmental monitoring, preliminary resource evaluation, and reporting to the DOE. The purpose of the project was to provide opportunities to scientists from many organizations for collection of the best samples and data available within the limitations of technical feasibility, safety and well integrity, and project budget. Kennecott Corporation was responsible for providing leaseholds and a permitted well site for the scientific well.

At the outset of Phase 1, Bechtel's main objectives were to:

- Drill to an initial depth of 4,000 ft (1,220 m), where the 572 °F (300 °C) isotherm was expected, and then drill an additional 6,000 ft (1,830 m)
- Take cores at depths selected by science management
- Provide time in the drilling schedule for downhole investigations, including logging and fluid sampling
- Conduct three limited flow tests in the course of drilling
  - From the first lost circulation zone below 3,000 ft (914 m)
  - From the first lost circulation zone below 6,000 ft (1,830 m)
  - At total depth of the well
- Provide collection stations for liquid and gas sampling
- Acquire selected commercial geophysical well logs to support research logging to be performed by the USGS
- Place the site on a 6-month, post-drilling standby with the well shut in, providing access for scientific study such as temperature and pressure buildup monitoring

Phase 2 additions to the Bechtel objectives included:

- Rework the well in August 1987 to reestablish a passageway to the bottom of the hole and to isolate production zones above 8,000 ft (2,440 m) with a new 7-in. liner cemented in place from approximately 5,700 to 8,600 ft (1,739 to 2,623 m)
- Construct facilities for a well flow test of 30-day duration
- Conduct a 30-day well flow test of the deep flow zones
- Clean up the site

This report addresses the results of the Phase 2 activities to fulfill these additional objectives.

1.2 SUMMARY OF PHASE 1

The results of the Phase 1 activities have been reported in "Salton Sea Scientific Drilling Program, Drilling and Engineering Program, Final Report, Volumes 1 and 2." This section summarizes the results of the Phase 1 activities.

In response to the original proposal solicitation by DOE, Kennecott offered to provide two well sites for which it had secured drilling permits, one for deep drilling and the other for injection of spent brine. The project site is in the southeast corner of Section 14, Township 11 S, Range 13 E, near the intersection of McDonald and Davis Roads, approximately 225 ft (68.6 m) below sea level. This site is in the northeastern part of the Salton Sea Geothermal Field, within 1 mile of five previous wells, several of which have been inundated by the rising level of the Salton Sea. Between the time of the proposal and the final project design, the injection well and the brine handling and disposal system were deleted from the project because of budgetary limitations. The injection well originally proposed, State 2-14, became the primary well, and a simplified brine-handling system was incorporated. Kennecott provided use of property on the east side of Davis Road for a brine storage pond. Details of the final design and site layout are presented in Section 3 of "Salton Sea Scientific Drilling Program, Drilling and Engineering Program, Final Report, Volumes 1 and 2."

The State 2-14 well was spudded on October 23, 1985, and in the following 160 days it was drilled to a depth of 10,564 ft (3,220 m). Thirty-six spot cores were taken, recovering approximately 725 ft (220 m) of sample. Two flow tests of limited duration (54 and 37 hours) were performed, one from an upper zone at 6,120 ft (1,865 m), and the second, a mixed-zone flow test from 6,000 ft (1,829 m) to bottomhole at 10,564 ft (3,220 m). Logging and fluid sampling were also performed.

At completion, the State 2-14 well had 9-5/8 in. production casing cemented to 6,000 ft (1,829 m) with uncemented 7-in. liner from 5,773 to 10,136 ft (1,760 to 3,089 m) in the 10,564 ft (3,220 m) hole. The purpose of the uncemented 7-in. liner was to keep the hole open for scientific logging for a 6-month period after well completion.

In late May 1986, USGS attempted temperature logs to a depth of 10,000 ft (3,048 m), but were able to obtain only a depth of 6,380 ft (1,945 m). During this run, the logging tool repeatedly stopped at 6,380 ft (1,945 m) going down the wellbore, and it also hung up consistently at 6,195 ft (1,888 m) coming up the well. The cause of the blockage at 6,380 ft (1,945 m) was determined to be separation and possible collapse of the fin hang-down liner. The cause of the hangup pulling out of the hole was believed to be a dogleg in the wellbore at about 6,200 ft (1,890 m).

In August 1986, rework was undertaken to reestablish access to the bottom of the well permitting temperature profile measurements. Rework involved removal of the liner hanger with attached liner and to replace it with a new hanger plus sufficient liner to tie into the lower string of the original liner. In late October 1986, the first temperature logging after the August 1986 rework was attempted, but the liner below 5,800 ft (1,768 m) was full of congealed drilling mud. This led to additional well rework in August 1987.

1.3 SUMMARY OF PHASE 2

1.3.1 Well Rework

The inability to run logging tools to the bottom of the well led to additional rework performed in August 1987. The objectives of this rework were to reestablish a passageway to the bottom of the hole and to cement off production zones above 8,000 ft (2,438 m) with a new 7-in. liner cemented in place, isolating the production zones below 8,000 ft for a long-term (30-day) flow test. The scope of work called for removal of the 7-in. repair liner installed in August 1986 and as much of the original 7-in. liner as possible. If the removal of the 7-in. liner proved slower than redrilling, the hole would be sidetracked and drilled as deep as possible below 8,000 ft (2,438 m) within budgetary constraints. A new liner would be installed and cemented to the 8,000 ft (2,438 m) depth to cement off shallower zones from deeper production zones.

The 7-in. repair liner that was installed during the first rework operation in August 1986 was retrieved without incident.

A second spear run engaged the top of the original 7-in. liner at a depth of 6,529 ft (1,990 m). Retrieval of the lower liner indicated that pulling the liner through the dogleg at about 6,200 ft (1,890 m) was going to be difficult.

Curtailment of fishing operations was considered prudent because of:

- Indications that the lower section of liner was probably full of debris
- Difficulty experienced in pulling the liner through the dogleg
- High probability of the well flowing while the liner was in the blowout preventer with no way to shut in the well

The decision was made to attempt to sidetrack the hole instead of continuing with the fishing operations. Sidetracking was not successful even though mud motors, a locked bottom hole assembly, and a conventional whipstock were used consecutively. After these unsuccessful attempts, no further efforts were made to reestablish a passageway to the bottom hole for logging tools.

A short flow test was conducted on August 31, 1987 after completion of the rework activities. The State 2-14 well was flowed for 12 hours averaging 569,000 lbm/hr of total flow (steam and liquid combined). The maximum production rate was 1,222,000 lbm/hr of total flow during the last half hour of the test when the throttling valve was fully open.

1.3.2 Construction of Flow Test Facilities

The flow test facility was originally designed, constructed, and used in 1982 to test a geothermal well at the South Brawley resource, which also produces hot, highly saline brine. The flow test equipment was subsequently disassembled, moved, reassembled, and used to test two wells in the Niland resource area. After the tests at Niland, the equipment was again disassembled, moved, and stored at the DOE facility at East Mesa. Prior to transporting the facility to the State 2-14 site, the high pressure separator was hydro-tested to determine its condition for reuse.

Construction of the flow test facility for testing the State 2-14 well was done in two parts. The first part was in the Fall of 1987; the second in May 1988. No other pieces of equipment were tested, although they were visually inspected.

In September 1987, when construction of the flow test facility began, the purpose of the facility design was an injection test of the nearby Imperial 1-13. For this test, the State 2-14 well would operate at virtually constant flow rate to furnish brine for injection into the Imperial well. Uninterrupted flow was a critical factor in the test, and redundant features as well as media filters were incorporated into the design.

Construction of the flow test facility was suspended in November 1987 due to uncertainty about funding. By May 1988 when construction resumed, a production-type resource evaluation test of the deep reservoir accessed by the State 2-14 well became the test objective replacing the injection test. Figure 1-1 shows a simplified flow diagram of the flow test facility as completed for the production well flow test, and Figure 1-2 shows the plot plan. Modification of the design included elimination of the media filters and piping of the Baker tanks for brine holding prior to injection.

For the production test, the two-phase geothermal fluid produced by the State 2-14 well flows to the high pressure separator, V-1. The brine liquid exits the separator from the bottom, with the steam leaving through the top.

The steam flow rate is measured using an orifice meter. Then the pressure is reduced by a pressure control valve that regulates the pressure in the separator. The steam is vented to the atmosphere through the vent silencer, V-4.

The separated brine exiting from the bottom of the separator flows through one of two parallel measuring loops. Two loops are provided for reliability because there is high potential for scaling in the brine flow line. The low pressure brine leaving the flow restriction orifice is a mixture of steam and liquid which flows to the atmospheric flash tank, V-3.

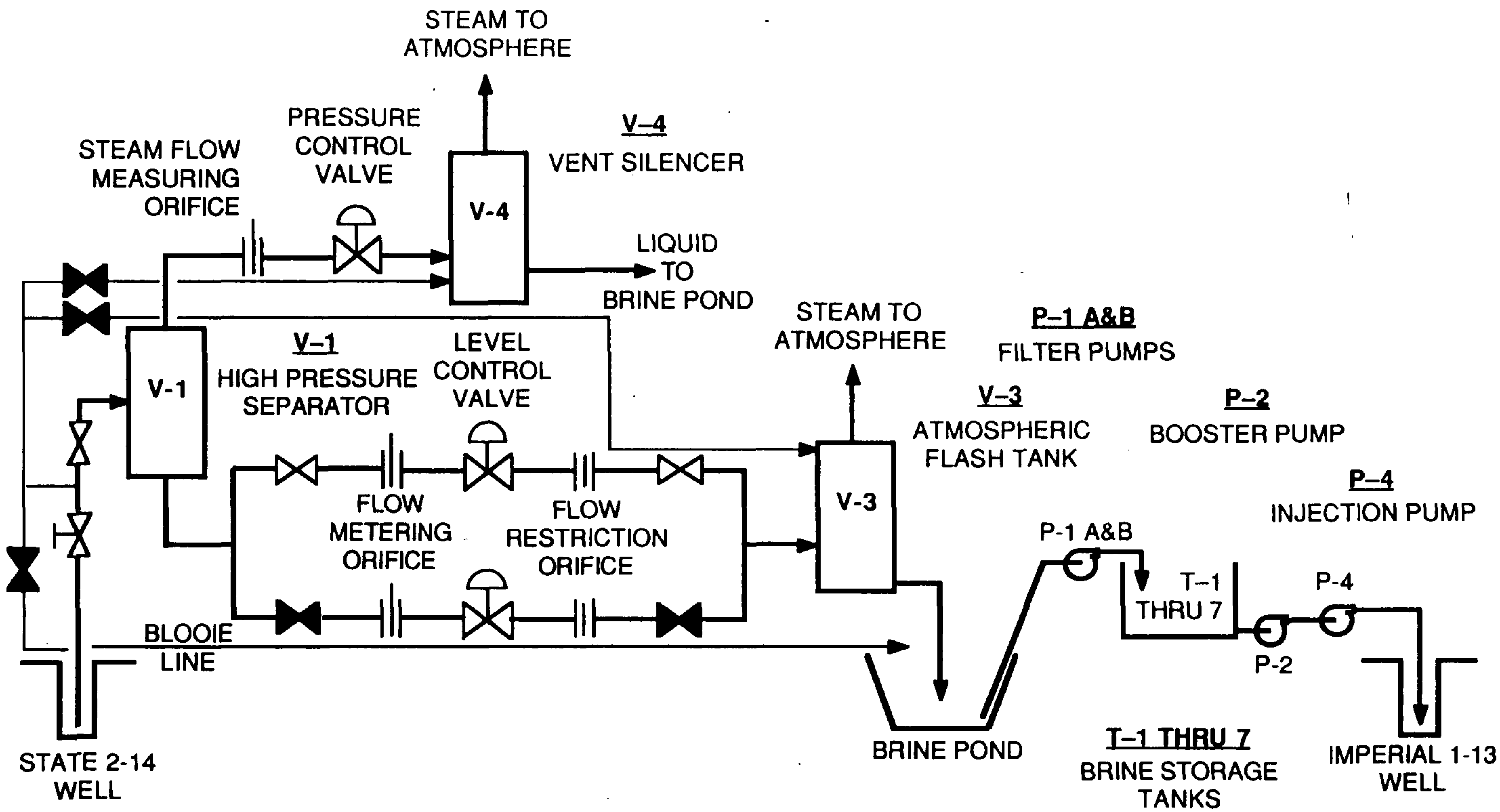


Figure 1-1 Simplified Flow Diagram of Test Facility

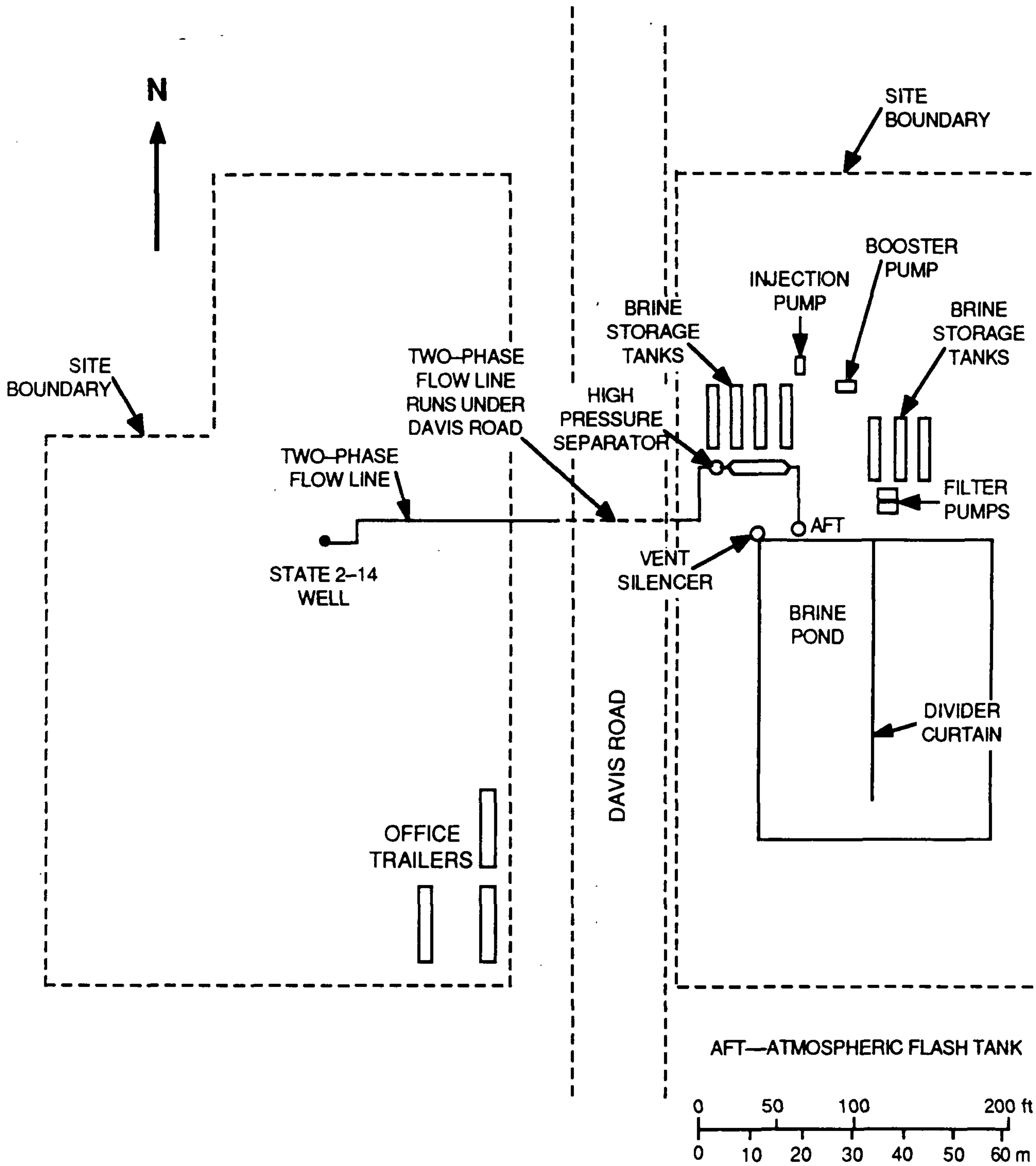


Figure 1-2 Plot Plan of Test Facility for Flow Test

Steam escapes to the atmosphere through the top of the atmospheric flash tank, and the liquid flows from the bottom into a brine pond. The brine pond provides surge capacity (i.e., storage) so that the production rate and the injection rate are not required to be exactly equal at all times. It also provides residence time for sludge to precipitate. To ensure residence time, a divider curtain forces the brine to flow to the south end of the pond and then back to the north end as it travels through the pond.

Liquid from the brine pond is pumped to the brine storage tanks, T-1 through 7, by one of the two filter pumps, P-1 A or B. Two full-capacity filter pumps are installed to provide high reliability. The seven 500-bbl brine storage tanks are connected in parallel to provide a region with low brine velocity for sludge to settle. This provides a safeguard against plugging the injection well with sludge inadvertently entrained in the brine pumped from the brine pond.

The brine from the brine storage tanks is pumped to the Imperial 1-13 well using a booster pump, P-3, and an injection pump, P-4, in series.

During the first part of construction in Fall 1987, the equipment was moved from storage at East Mesa, the vessels were set in place, and the piping was connected after reconditioning. The instruments were stored rather than installed.

Construction of the flow test facility resumed on May 1, 1988 with a scheduled start date of June 1, 1988 for the well flow test. During May, some changes to the piping were made, the piping installation was completed, hydrostatic leak tests were performed, the instrumentation and controls were installed, and the rental pumps were installed for the well flow test.

Well flow from the State 2-14 well began on June 1, 1988. At the start, flow bypassed the separator and entered the brine pond first through the blooie line and later through the atmospheric flash tank, V–3. Installation of pumps and piping to transfer brine from the pond to the brine storage tanks was completed on June 3. The next day, installation of the booster pump on the injection line was completed, and injection began. On June 6, two-phase flow was admitted to the high pressure separator. This concluded the construction phase of the well flow test.

1.3.3 Flow Test

Well and Reservoir Test. A 19-day step-rate flow test of the State 2-14 well was conducted from June 1-20, 1988. In the first 13 days of testing, there were three rate steps of 2 to 7 days' duration with flow rates from 125,000 to 400,000 lbm/hr (57,000 to 181,000 kg/hr). An attempt was made to achieve stable operation at 750,000 lbm/hr (340,000 kg/hr), but operational problems and limitations of the brine injection system prevented extended operation. A flow rate of 768,000 lbm/hr (348,000 kg/hr) was achieved on June 15, but this was maintained for less than 1 hour when problems with the separator level control curtailed activity. Through the remaining 5 days, pump mechanical failures and persistent cavitation problems in the brine pumps limited the capacity for brine disposal, which became the governing factor on the well flow rate. On June 20, it was possible to increase the flow rate to 386,000 lbm/hr (175,000 kg/hr).

The operational problems mentioned above resulted in frequent flow rate changes and shortened rate steps in the last 6 days. However, most of the data acquired during that period were useful for defining the production characteristics of the well.

During the first rate step, the well was produced at about 125,000 lbm/hr (57,000 kg/hr). This was significantly lower than the planned initial rate of 200,000 to 250,000 lbm/hr (91,000 to 113,000 kg/hr) because the test facility was incomplete and the residual brine had to be retained in the brine pond until the injection system was operational on June 4th. Budgetary and schedule constraints required the test to start as scheduled, and the injection system was completed while the test operations proceeded.

After the injection system was operational, the rate was held at about 125,000 lbm/hr (57,000 kg/hr) until June 8, when the separator was placed in service and direct flow measurements of the separated steam and brine were possible. Late on June 8, the flow rate was increased to 250,000 lbm/hr (113,000 kg/hr).

For purposes of reservoir engineering analysis and chemical sampling, the test was scheduled as a series of rate steps (constant-rate flow periods) with stepwise flow rate increases in between. The planned duration of each rate step was 7 days, based on a conservative estimate of the time required to reach stable operation. However, early in the test the well stabilized very quickly. The test plan was therefore revised to employ 3-day rate steps with a 6-day flow period at the end of the test.

Downhole temperature and pressure profile surveys were conducted on June 5, 12, 14, and 20. Pressure drawdown was recorded as the rate was increased on June 12 and 14, and the pressure buildup was recorded for 44 hours after the shutin on June 20.

A period of production at high flow rate (>1,000,000 lbm/hr or 454,000 kg/hr) directly into the brine pond was planned to follow the shutin and pressure buildup. The purpose was to define a higher point on the deliverability curve within the expected commercial operating range. However, the well would not flow spontaneously when the valves were opened, and two attempts to induce flow were unsuccessful. This was probably because the wellbore had cooled during the shutin, and therefore was not an indication of well damage or depletion. In attempts to induce flow, common techniques of pressuring the well with air at the wellhead and displacing brine from the wellbore with fresh water were employed. More effective, yet lengthy and expensive methods, such as nitrogen lift or heating up the well for a few days with fresh water in the wellbore, were precluded by budgetary constraints.

The results of the flow test and reservoir analysis are summarized as follows:

- Reservoir engineering analysis of the pressure buildup test indicates that the near-well reservoir has a transmissivity of about 233,600 md-ft and a skin factor of +23.1. This indicates a highly productive reservoir with some near-well impairment, probably caused by drilling and workover operations.

- The well has high productivity and is capable of flow rates greater than 800,000 lbm/hr (363,000 kg/hr) at 250 psig wellhead pressure. At 800,000 lbm/hr (363,000 kg/hr), it could produce approximately 12 MWe in a dual-flash power plant.

- Analysis of the June 5 temperature survey data indicates flash initiation at a depth of about 3,200 ft (975 m) and a temperature of 570 °F (299 °C). Based on analyses of brine samples collected from the flowline and on thermodynamic flash calculations, the total dissolved solids of the preflash brine is about 247,000 mg/kg, and the steam flash to atmospheric pressure is about 26 percent.

- Well productivity improved during the course of the flow test. On at least two occasions (June 2 and 5), there were rapid increases in the wellhead pressure that were not associated with any flow rate change. This strongly suggests that the productivity suddenly improved. This is unusual and probably resulted from the brine flow clearing blockages inside the wellbore or in nearby formation fractures.

Chemical Sampling. The primary objective of the brine chemistry sampling program was to characterize the brine produced by the State 2-14 well during the flow test in June 1988.

Chemical sampling was supervised by Kennecott, and the primary chemical analyses were conducted for the Electric Power Research Institute (EPRI) by Combustion Engineering, Inc. using the EPRI Mobile Geothermal Chemistry Laboratory that was on site during the flow test.

Three types of sampling events were conducted during the flow test. Signature tests, measuring 64 chemical species, were conducted at each of the three rate steps to characterize the chemical and physical characteristics of the total well flow. Tracking tests were performed daily to observe changes in selected properties as a function of time. Special tests were conducted as needed to investigate flow streams or equipment of special interest.

The primary focus was on the results of the signature and tracking tests yielding information needed to characterize the brine.

The following conclusions are readily drawn from the brine chemistry results:

- Total dissolved solids (TDS) increased for the second and third rate steps.
- Sodium and potassium increased 7 and 12 percent, respectively, but calcium increased 33 percent from the first to the third rate step.

The TDS concentration and the geothermometers, Na/K, Na/Ca, and Ca/K, were examined for indications that various zones were producing in different proportions as the well flow was varied during the flow test. The results for the June 1988 flow test were compared with similar indicators from the short flow test of the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) in December 1985, and the short flow test conducted shortly after well completion in March 1986.

The TDS concentration varied little during the flow test even though the flow rate varied over a range of 7:1. A slight increase in the TDS concentration occurred as the well flow rate was increased for the second rate step. Initially, the TDS concentration was about 235,000 mg/kg, which increased to about 250,000 mg/kg. No other significant changes were observed after this shift between the first and second rate steps.

During the flow test in June 1988, the Na/Ca and Ca/K ratios changed considerably (-20 and +19 percent, respectively), while the Na/K ratio changes were less dramatic (+8 percent from the first to second rate steps and -4 percent from the first to the third). These changes in the geothermometers, Na/K, Na/Ca, and Ca/K, lead to the following conclusions:

- More than one zone is producing a significant portion of the total well flow.
- The various zones may be producing different proportions of the total flow as the well flow is increased.

Comparison of the Na/K, Na/Ca, and Ca/K ratios for the second rate step during the June 1988 flow test with the corresponding ratios for the March 1986 test shows very little difference. Therefore, the producing zones and their relative contributions were essentially the same for the two test conditions.

The information for the December 1985 test and the data for the flow test in June 1988 permit comparison of fluids produced from 6,000 to 6,200 ft (1,829 to 1,890 m) depth with fluids that are from several different zones. The fluid produced by the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) in December 1985 appears higher in potassium and roughly equal in sodium, calcium, and TDS concentrations to the fluids produced in June 1988. Curiously, these generalizations apply more closely for the second and third rate steps than for the first; one hypothesis is that the higher well flow rates may favor production from the relatively shallow zone from 6,000 to 6,200 ft (1,829 to 1,890 m).

The chemistry and static (nonflowing) temperatures for the State 2-14 well were compared with those for 11 other wells in the vicinity for which data are available as nonproprietary information.

In general, the wells to the southwest of State 2-14 have lower TDS concentrations. Although depth has often been reported as an important factor with respect to TDS, the River Ranch No. 1 and Sportsman No. 1 wells, which are near State 2-14, produce fluid with relatively high TDS concentration from relatively shallow production zones starting at about 4,000 ft (1,219 m) depth.

State 2-14 and the wells near it tend to have relatively low values of Na/Ca ratio. The wells in the vicinity of State 2-14 tend to have lower Na/K ratios than does State 2-14; this may be due, at least in part, to greater depth of its production zones. Generalizations concerning Ca/K are not apparent.

Because of virtually identical sodium, potassium, and calcium concentrations and similar depth of the production zones, the geothermal fluid produced from the zone between 6,000 to 6,200 ft (1,890 m) depth in the State 2-14 well and the fluid produced from the nearby Hudson No. 1 well probably arise from the same source.

Temperatures in the State 2-14 well seem to track those in the nearby River Ranch No. 1 well from 3,000 to 5,000 ft (914 to 1,524 m); however, at 6,000 and 7,000 ft (1,829 and 2,134 m), the temperatures are 23 and 20 °F (13 and 11 °C) higher, respectively, in the River Ranch No. 1 well.

The temperatures in the State 2-14 well are 120 to 130 °F (67 to 72 °C) lower than those in the Elmore No. 1 well for all depths from 3,000 to 7,000 ft (914 to 2,134 m). Likewise, the temperatures in the State 2-14 well are 80 to 120 °F (44 to 67 °C) lower than those in the IID Nos. 1 and 2 wells from 3,000 ft (914 m) to the total depths for the IID wells, 5,213 ft (1,589 m) for IID No. 1, and almost 6,000 ft (1,829 m) for IID No. 2.

Scientific Research Projects. The following research organizations conducted the indicated scientific research projects during the June 1988 flow test of the State 2-14 well:

- Battelle Pacific Northwest Laboratories. Particle meter testing to
  - Establish the suspended solids content of the separated brine
  - Characterize the chemical and size characteristics of the suspended solids
  - Evaluate an online computerized ultrasonic particle counter
  - Evaluate the effects of scale deposits on the optical window of a laser particle counter
- Electric Power Research Institute. Chemical sampling and analysis to characterize the brine
- Lawrence Livermore National Laboratory. Seismic monitoring to characterize the microseismic activity related to the flow–injection test in the Salton Sea Geothermal Field
- New Mexico State University. Collection and analysis of brine samples to measure metal ion concentrations
- University of California at Riverside. Collection and analysis of fluid and solid samples to study the transport of platinum group elements, gold, and sulfur in the Salton Sea geothermal brines
- University of Southern California. Fluid sampling and uranium series isotope measurements to
  - Constrain models of radioisotope exchange mechanisms
  - Develop new methods of estimating hydrogeologic parameters
- University of Utah Research Institute. Liquid and gas sampling and analysis to determine
  - Differences in the chemistry of the fluid as a result of changing flow rates
  - Silica precipitation when a cooling coil is used during sample collection

1.3.4 Site Cleanup

The objective of the site cleanup activities is to clean the site and equipment sufficiently to turn them over to Kennecott subject to the following specific conditions:

- The equipment and trailers furnished by DOE are to be left in place for DOE to transfer ownership to Kennecott.
- The mud pit and brine pond are to be cleaned to a condition suitable for reuse.

The equipment and trailers required little cleanup because they were to be assumed "as is." Housekeeping procedures during the flow test had kept these in reasonably good shape.

The mud pit was cleaned in late May during preparations for the flow test. At that time, the mud pit was dry with several inches of dried drilling mud residue in the bottom. This nonhazardous material was scraped up, loaded, and hauled to the IT Corporation disposal site near Westmoreland, California. Since the mud pit was not used during the flow test, it required no further cleaning.

Cleaning the brine pond presents a greater problem. The results of chemical analyses of the sludge solid waste in the brine pond are highly variable, but they indicate that the waste may be hazardous. Various methods to dewater or treat the solid waste have been proposed by potential contractors; however, at the time this report draft was prepared in late August 1988, the brine pond cleanup contractor and process had not been selected.

Section 2

WELL REWORK

2.1 BACKGROUND

At completion in March 1986, the State 2-14 well had 9-5/8 in. production casing cemented to 6,000 ft (1,829 m) with an uncemented hang-down 7-in. liner from 5,773 to 10,136 ft (1,760 to 3,089 m) in the 10,564 ft (3,220 m) hole. The purpose of the uncemented 7-in. liner was to keep the hole open for scientific logging for a 6-month period after well completion.

In late May 1986, USGS temperature logs that were scheduled to reach 10,000 ft (3,048 m) were obtained only to a depth of 6,380 ft (1,945 m). During this run, the logging tool repeatedly stopped at 6,380 ft (1,945 m) going down the wellbore, and it repeatedly hung up at 6,195 ft (1,888 m) coming up. It was believed that the hangup at 6,195 ft (1,888 m) was caused by a dogleg in the hole created when the well was directionally drilled.

Diagnostic testing in June 1986 indicated the following:

- The liner had separated at a collar at 6,181 ft (1,884 m)
- Open hole existed from 6,181 to 6,422 ft (1,884 to 1,957 m)
- The liner was not badly corroded or worn

In August 1986, rework was undertaken to remove the liner hanger and attached liner and to replace it with a new hanger and sufficient liner to tie into the lower string of original liner. This was intended to reestablish access to the bottom of the well permitting temperature profile measurements. The field work began on August 7, 1986 and was completed on August 21. The liner hanger and nine joints of 7-in. liner were removed. A tapered mill was then run inside the lower liner from 6,521 to 8,005 ft (1,988 to 2,440 m). Then, 793 ft (242 m) of a 7-in. patch liner (no liner hanger) was installed from 5,728 to 6,521 ft (1,746 to 1,988 m) as illustrated in Figure 2–1. The August 1986 rework is discussed in Section 4.9 of "Salton Sea Scientific Drilling Program (SSSDP), Drilling and Engineering Program, Final Report, Volumes 1 and 2."

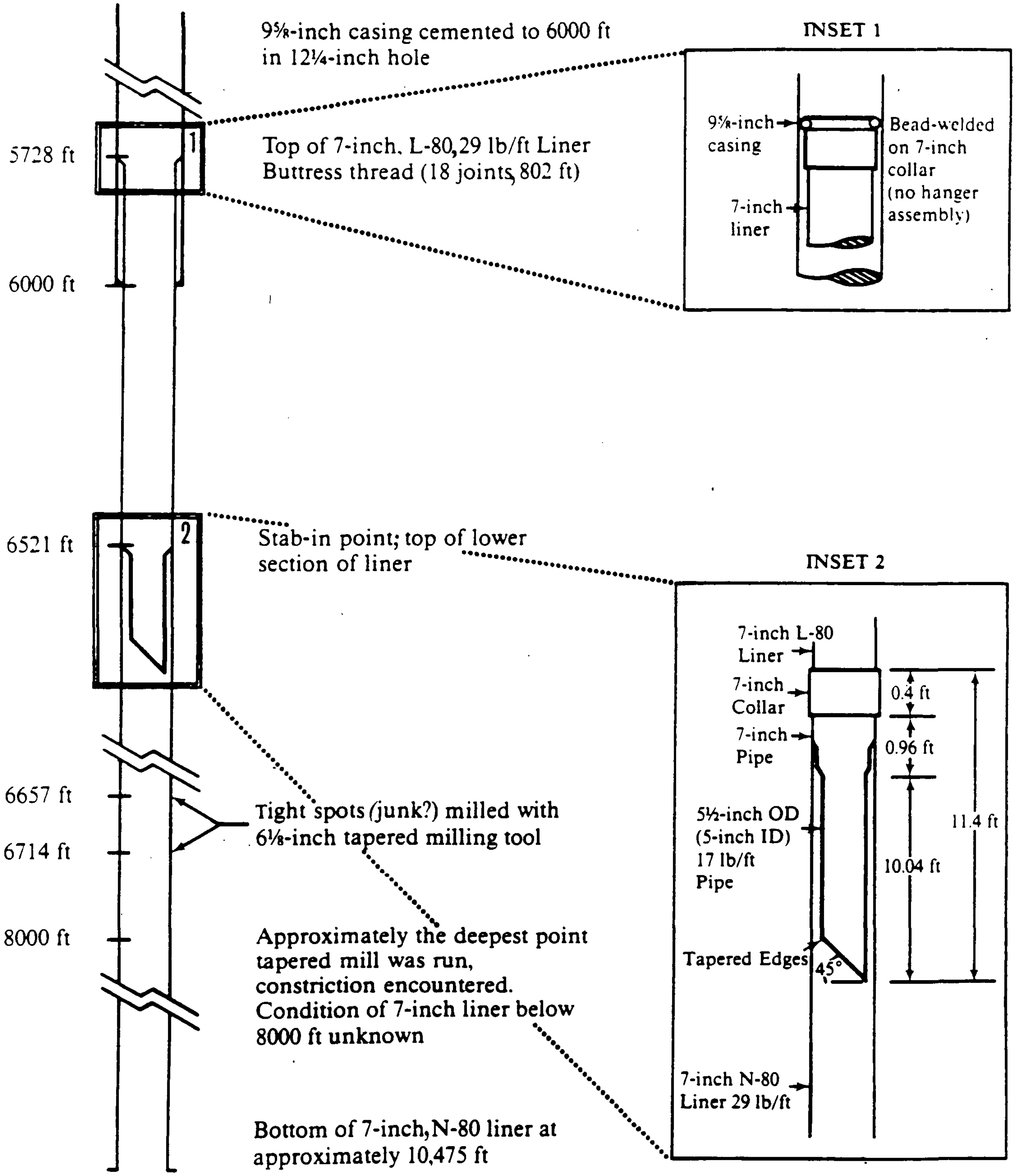


Figure 2-1 Schematic of Wellbore Construction After August 1986 Repairs

On the first temperature logging attempt, in late October 1986, following this rework, the liner was found to be full of congealed drilling mud from 5,800 to 6,717 ft (1,768 to 2,047 m), the greatest depth to which a sinker bar could be driven. The most likely explanation for the drilling mud in the liner is that during the final water displacement of the drilling mud in August, the water flush evidently flowed around the outside of the repair liner instead of flowing through it, leaving the liner full of drilling mud.

The inability to run logging tools to the bottom of the well led to additional rework in August 1987.

2.2 WELL REWORK IN AUGUST 1987

The objectives of the rework in August 1987 were to reestablish a passageway to the bottom of the hole and to isolate production zones above 8,000 ft (2,438 m) with a new 7-in. liner cemented in place.

The scope of work called for removal of the 7-in. repair liner installed in August 1986 and as much of the original 7-in. liner as possible. If the removal of the 7-in. liner proved slower than redrilling, the hole would be sidetracked to the deepest depth possible below 8,000 ft (2,438 m) and a new liner would be installed and cemented to the 8,000 ft (2,438 m) depth to isolate zones shallower than this point from the deeper production zones.

Field work began on August 1, 1987 with mobilization of the drilling rig, and the repair work was terminated with demobilization of the drilling rig on September 2, 1987. Appendix A contains the daily drilling reports, and the following summarizes the rework activities:

Date	Activity
7/31/87	NU BOPE and test to 2,000 psi (13.8 MPa), witnessed and approved by CDOG. RU USGS wireline unit and ran temperature survey to 3,000 ft (914 m). Maximum temperature was 610 ^{o}F at 3,000 ft (321 ^{o}C at 914 m). POH with first temperature tool. RU and RIH with second temperature tool. Wellhead pressure 275 psi (1.9 MPa).

8/1/87	Ran second temperature log to 6,000 ft (1,829 m). POH with temperature tool and found that tool had failed due to fluid leakage. Drilled and installed mouse hole. Pumped 2,300 bbl (366 m^3) of fresh water into well to kill and cool well.
8/2/87	Pumped 1,700 bbl (270 m^3) of 9.2 lbm/gal (1.10 kg/l) brine into well from brine pond. PU and RIH with spear and jars. Tagged top of 7-in. repair liner at 5,744 ft (1,751 m). Jarred repair liner loose and POH with liner.
8/3/87	POH, flame cut and lay down 18 joints (802 ft, 244 m) of 7-in., 29 lbm/ft, L-80, BTC casing plus a 10 ft (3 m) joint of 5-1/2-in. casing. Recovered all of the repair liner. RIH with shear and jars again and tagged fish at 6,529 ft (1,990 m). POH with fish to last drill collar, and well started to flow. Closed ABOP and bullheaded brine down the well. Note: Great difficulty was experienced while pulling this casing through the dogleg section of the hole. The casing hung up five times in the dogleg causing the jars to trip.
8/4/87	Finished killing well. POH and lay down 5 joints of 7-in., 29 lbm/ft, N-80, BTC casing. Pin end of last joint was split and joint was full of debris. Killed well with 1,285 bbl (204 m^3) of brine. MU BHA, RIH, and tagged top of 7-in. liner at 6,699 ft (2,042 m). POH to 5,974 ft (1,821 m) and killed well with brine. RIH to 6,308 ft (1,923 m) and placed a 360 ft^3 (10 m^3) of Class G, 40% silica flour cement plug. CIP at 6:00 pm. WOC.
8/5/87	Tagged cement top at 6,036 ft (1,840 m) and drilled cement to 6,048 ft (1,843 m), witnessed by CDOG. POH and shut well in--well flowing. RIH to 5,956 ft (1,815 m), circulate, and build mud system.
8/6/87	Continued building mud system. Shut-in well and worked on mud chillers. Circulated well with fresh water while repairing chillers. POH, MU directional drilling assembly and RIH. Drilling assembly consisted of positive displacement motor (PDM), 1-1/2 degree bent sub, and a monel collar. Staged in hole to 6,036 ft (1,840 m) and dressed cement plug off to 6,058 ft (1,846 m).
8/7/87	Surveyed and oriented PDM at 6,058 ft (1,846 m). Unable to start mud motor. POH with mud motor and RIH with new PDM. Ran directional survey to orient mud motor. Rig engines died while running survey. Restarted engines and POH. Shut well in and worked on rig engines. Engines were shutting down due to overheating. Ambient temperatures were 108 ^oF (42 ^oC) with 56% relative humidity.
8/8/87	Worked on rig engines.

8/9/87 Finished rig engine repair. Ran all three engines under full load for 2 hours without any problems. Function tested BOPE. ABOP rubber in bad shape. Changed out ABOP.

8/10/87 Finished changing out ABOP. RIH to 5,987 ft (1,825 m), closed ABOP, and circulated through choke manifold with water to cool well. POH.

8/11/87 PU and tested mud motor. Mud motor would not run. Lay down PDM, and PU turbo motor and tested okay. Staged in hole to 6,063 ft (1,848 m). Ran directional survey and oriented tool. Turbo would not start. POH and lay down turbo. MU locked BHA and RIH.

8/12/87 RIH to top of cement at 6,094 ft (1,857 m) and attempted to cut shoulder from 6,094 to 6,133 ft (1,857 to 1,869 m). POH with locked assembly and PU turbo motor. RIH with turbo motor and attempted to sidetrack hole. Motor would only drill while rotating drill pipe. Drilled to 6,163 ft (1,878 m) and POH. PU BHA and RIH to 6,235 ft (1,900 m).

8/13/87 Drilled through cement plug at 6,480 ft (1,975 m) and cleaned out to 6,636 ft (2,023 m). Pulled up into casing, and well started flowing. Shut well in and bullheaded mud down the casing. Waited on orders from DOE. Started building mud volume. RIH with maximum recording thermometer. Temperature 442 ^{o}F at 6,600 ft (228 ^{o}C at 2,012 m) after 13-hr shut in. Re-ran temperature to 5,900 ft (1,798 m) while pumping into well. Received orders to sidetrack with a conventional whipstock.

8/14/87 Temperature was 300 ^{o}F at 5,900 ft (572 ^{o}C at 1,798 m). POH with drill pipe, and well started flowing. Bullheaded brine down the casing to kill well. RIH with drill pipe to 6,611 ft (2,015 m) and RU B. J. Titan to cement. Spotted 93 ft^3 (3 m^3) of Class G, 40% silica flour cement. POH, and well started flowing. Killed well and continued POH. Shut in well and WOC.

8/15/87 RIH with BHA and tagged top of cement at 6,508 ft (1,984 m). Polished off cement to 6,531 ft (1,991 m). Well started flowing. Bullheaded brine to kill well. POH and PU conventional whipstock. RIH with whipstock and hit fill at 6,515 ft (1,986 m). Attempted to circulate to 6,531 ft (1,991 m). Ran directional survey to orient tool. Directional drilling supervisor became sick and had to be taken to hospital. POH with whipstock tool.

8/16/87 POH and lay down whipstock tool. MU BHA and RIH to 2,751 ft (839 m). Drum brakes failed and shut down to repair brakes. Staged in hole to 5,976 ft (1,821 m) and conditioned hole.

8/17/87	RIH and tagged fill at 6,509 ft (1,984 m). Cleaned out fill to 6,531 ft (1,991 m) and drilled cement to 6,537 ft (1,992 m). Circulated and conditioned hole. Made short trip to check fill and spotted a 9.4 lbm/gal (1.13 kg/l) gel pill at 6,537 ft (1,992 m). POH for whipstock tool. RIH with whipstock tool to 6,528 ft (1,990 m) and circulated tool to 6,536 ft (1,992 m). Ran directional survey and oriented whipstock. Sheared pin and drilled a 6-in. (15 cm) pilot hole to 6,547 ft (1,996 m).
8/18/87	POH with whipstock and PU bullnose guide and 8-1/2 in. (22 cm) hole opener. RIH with hole opener and opened hole from 6,537 to 6,547 ft (1,992 to 1,996 m). POH with hole opener and PU 8-1/2 in. (22 cm) bit. RIH and reamed from 6,537 to 6,547 ft (1,992 to 1,996 m). Drilled from 6,547 to 6,630 ft (1,996 to 2,021 m) where bit fell through. Continued drilling to 6,717 ft (2,047 m).
8/19/87	Drilled to 6,737 ft (2,053.4 m) and hit top of old 7-in. liner. Attempted to drill by liner and drilled to 6,738 ft (2,053.7 m). POH and PU a new bit and reamer. RIH to 6,738 ft (2,054 m) and drilled to 6,741 ft (2,055 m). POH and PU junk mill.
8/20/87	RIH to 6,741 ft (2,055 m) and milled to 6,748 ft (2,057 m). POH and lay down junk basket and mill. RIH with bit to 6,743 ft (2,055 m). Reamed from 6,743 ft (2,055 m) to 6,748 ft (2,057 m) and drilled from 6,748 to 6,751 ft (2,057 to 2,058 m). POH.
8/21/87	POH and changed bit and BHA. RIH to 6,751 ft (2,058 m) and drilled to 6,818 ft (2,078 m). Directional survey at 6,790 ft (2,070 m) was 6-3/4 degrees at S 13° W. POH for new bit. RIH with new bit and stabilizer.
8/22/87	RIH to 6,750 ft (2,057 m). Reamed from 6,750 to 6,818 ft (2,057 to 2,078 m) and drilled from 6,818 to 6,958 ft (2,078 to 2,121 m). Stuck pipe and pulled free. Hole tight from 6,958 ft (2,121 m) back to 6,000 ft (1,829 m). POH and changed out bit and stabilizer.
8/23/87	RIH and reamed from 6,880 to 6,958 ft (2,097 to 2,121 m). Drilled from 6,958 to 7,080 ft (2,121 to 2,158 m).
8/24/87	Drilled to 7,100 ft (2,164 m) and POH for bit. Left three cones in hole. RIH with new bit and junk sub. Worked by junk and drilled to 7,180 ft (2,188 m). Ran directional survey at 7,155 ft (2,181 m) and film was burned up. POH and had tight hole from 7,180 to 6,000 ft (2,188 to 1,829 m).
8/25/87	POH and MU new bit and jars. RIH to 7,071 ft (2,155 m) and hit junk. Unable to drill past junk. POH for mill. RIH with flat bottom mill and milled from 7,070 to 7,083 ft (2,155 to 2,159 m).

8/26/87	Milled from 7,083 to 7,101 ft (2,159 to 2,164 m). POH with mill. Changed well over to fresh water. POH to 6,631 ft (2,021 m), and well started flowing. Started killing well with brine.
8/27/87	Finished killing well with brine. POH and lay down Hevi-Wate drill pipe and drill collars. Closed master gate valve and nippled down BOPE. Lay down drill pipe in mouse hole.
8/28/87	Continued laying down drill pipe in mouse hole. Master gate valve leaking. Nippled up BOPE and ran a Baker Model C retrievable bridge plug. Nippled down BOPE and changed out master valve. Nippled up BOPE and retrieved bridge plug. Nippled down BOPE and nippled up wellhead and flow line.
8/29/87	Refabricated flow line to fit sub-base of rig and continued laying down drill pipe in mouse hole.
8/30/87	Continued laying down drill pipe and installing flow line. Pressure tested flow line to 750 psi (5.2 MPa). Flowed well into reserve pit for 1-1/4 hours to check out equipment. Maximum temperature and pressure were 190 °F (88 °C) and 120 psi (0.8 MPa) when shut in. Finished repairing flash tank.
8/31/87	Monitored well pressure until 6:00 am. Wellhead pressure was 70 psi (0.5 MPa). Started flow test and flowed well until 8:00 pm. Shut in well and allowed wellhead and flow line to cool down. Rig started demobilizing.
9/1/87	Rig released at 10:00 am.

2.2.1 Logging and Surveying

Before the well was disturbed with the fishing operations, the USGS ran two temperature surveys. The first survey was limited to 3,000 ft (914 m) where the temperature reached 610 °F (321 °C), the maximum temperature for using the wireline system. A second temperature log by the USGS was made to 6,000 ft (1,829 m) with a digital temperature tool. This tool failed due to leakage of fluid into the tool.

Directional surveys were taken for orienting the mud motors and the whipstock tool while attempting to sidetrack the hole. Only two surveys were run after drilling-by the 7-in. liner stub at 6,741 ft (2,055 m). The results of the directional surveys are as follows:

Depth (ft)	Angle (degrees)	Azimuth	Remarks
6,038	8	N75E	
6,537	5	N38W	
6,790	6–3/4	S13W	Possible magnetic interference
7,030	8–1/2		Film fogged by heat

1 ft = 0.305 m

2.2.2 Casing Retrieval

The 7-in. repair liner that was installed during the first rework operation in August 1986 was retrieved without incident. Eighteen joints of liner (802 ft, 244 m) plus the 10 ft (3 m) x 5-1/2 in. stab-in joint were removed from the well. Inspection of the repair liner showed it to be in good condition with little or no corrosion.

A second spear run engaged the top of the original 7-in. liner at a depth of 6,529 ft (1,990 m). Retrieval of the lower liner indicated that pulling the liner through the dogleg at about 6,200 ft (1,890 m) was going to be difficult. The liner stuck several times coming through the dogleg causing the jars to trip.

Five joints (210 ft, 64 m) of 7-in., 29 lbm/ft, N-80, LTC casing were recovered. The pin end of the fifth joint was split indicating that it had dropped onto the collar below it. Additionally, the last joint of liner was packed full of rocks, baked mud, and some centralizer springs. Inspection of the recovered liner showed it to be in relatively good condition, with some corrosion and no stress cracking in the collars.

Curtailment of fishing operations was considered prudent because of:

- Indications that the lower section of liner was probably full of debris
- Difficulty experienced in pulling the liner through the dogleg
- High probability of the well flowing while the liner was in the blowout preventer with no way to shut in the well

The decision was made to attempt to sidetrack the hole instead of continuing with the fishing operations.

2.2.3 Directional Drilling

Methods for Directional Drilling. There are fundamentally two methods for directional drilling to sidetrack a hole. The more common method is the mud motor using a bent sub. The other method is the conventional whipstock. Both methods rely on a good cement plug being set at the point from which the hole is to be sidetracked.

Mud motors consist of two types:

- Positive displacement motor (PDM). PDMs use an elastomer stator to radially seal around a helical spiraled steel rotor.
- Turbine motor. Turbine motors are comprised of a series of steel-bladed rotors and stators similar to a jet engine.

The turbine motor is more commonly used in geothermal drilling because of its ability to operate at slightly higher temperatures [approximately 300 $^{\circ}$F (149 $^{\circ}$C) versus 260 $^{\circ}$F (127 $^{\circ}$C) for a PDM]. However, the radial and thrust bearings of a turbine motor can also be destroyed by exposure to excessive temperature.

A conventional whipstock consists of a long tapered wedge of steel that is concave on one side to hold and guide a bit against the side of the hole. This tool is still used in extremely hot holes or holes that are difficult to sidetrack. The disadvantage of the whipstock is that using it is more time consuming and therefore more expensive.

Sidetracking the State 2-14 Well. The initial approach to sidetracking the State 2-14 well was to start the sidetrack above the dogleg at 6,200 ft (1,890 m). This would eliminate the dogleg problem for the next liner installation.

A cement plug was set from 6,036 to 6,480 ft (1,840 to 1,975 m) with 360 ft^3 (10 m^3) of cement. Three samples of the cement were taken during the cementing operation, and each indicated that a good hard cement plug had been set.

Four mud motor, one locked bottom hole assembly, and two whipstock runs were made in attempting to sidetrack the hole. A brief summary of the results with each run follows.

Run No. 1 Using a Mud Motor. Since mud return temperatures were low (about 115 °F or 46 °C) and injection of 5,000 bbl (795 m^3) of cold water was assumed to have cooled the wellbore, a PDM was chosen for the first run because it has higher torque for a lower flow of mud. It is also usually easier to start than a turbine motor.

To ensure that the PDM would stay cool, it was staged in the hole. That is, circulation was established at 2,000-ft (610 m) intervals while tripping in the hole.

After tagging the cement plug, the plug was dressed off from 6,036 to 6,058 ft (1,840 to 1,846 m) before running a survey to orient the tool. The orientation shots took about an hour during which the mod motor was not circulated.

After the orientation shots, the mud motor would not start.

The PDM was then pulled out of the hole and checked. The bit shaft could be turned by hand (which is normally impossible); therefore, the failure of this PDM was initially judged to be the result of shearing the coupling between the power shaft and the bit shaft. However, failure of the elastomer stator from excessive temperature could produce a similar effect.

Run No. 2 Using a Mud Motor. A second PDM was staged in the hole. While a directional survey was being completed, one of the rig engines went down causing a complete power failure. The PDM was on bottom without circulation for 1-1/2 hours before it could be pulled from the hole. Upon retrieval, the PDM was tested and appeared to be in good condition. However, after repair of the rig engines, the PDM was tested again, and it would not run.

Run No. 3 Using a Mud Motor. The first turbine motor was picked up and tested before staging in the hole. The motor was run to 6,063 ft (1,848 m) where an hour was required to survey for orienting the tool. After surveying, the motor would not start, and it was pulled from the hole. Inspection at the surface revealed that the elastomer thrust bearing was shattered.

Run No. 4 Using a Mud Motor. A second turbine motor was tested at the surface and then run to the bottom of the hole as fast as possible without staging. Since temperature appeared to be the problem, the faster transit was expected to alleviate the problem. Nevertheless, the motor failed to start, and it was pulled from the hole.

Run Using a Locked Bottom Hole Assembly. After the mud motor failures, an attempt was made to effect a sidetrack in the 5-degree dogleg at about 6,200 ft (1,890 m) using a locked-up drilling assembly. Such a stiff assembly will often sidetrack when it encounters a dogleg; however, this attempt was unsuccessful and ended up in drilling out the cement plug. This necessitated setting another cement plug before using a whipstock.

Run No. 1 Using a Whipstock. A whipstock tool was run in the hole. While a directional survey was being conducted to orient the tool, the supervisor for directional drilling collapsed and was taken to the hospital. The tool was pulled from the hole and a bit run was made to clean out 17 ft (5 m) of fill while waiting for a new directional man to arrive.

Run No. 2 Using a Whipstock. The whipstock tool was re-run, and a 6-in. (15 cm) pilot hole was drilled. This was followed by an 8-1/2 in. (22 cm) hole opener that was in turn followed by an 8-1/2 in. bit.

While dressing-off the cement plug, the cement appeared to be relatively soft. However, cutting samples during the whipstock operation indicated hard cement mixed with formation cuttings. During the drilling operation, the cuttings began to grade more toward cement, indicating that the bit had wandered back into the original hole. Eventually, the bit penetrated the lower bound of the cement plug.

Review of the Data. Temperature measurements taken shortly after the PDM runs using a maximum recording thermometer show a temperature of 302 ^{o}F at 6,000 ft (150 ^{o}C at 1,829 m). The failure of the PDMs is traceable to high temperatures.

The cause of the failure of the turbine motors was not immediately evident. One hypothesis in the field was that the motors may have become blocked by debris since mud screens had not been used; however, a subsequent report by Eastman, after the motors were torn down and inspected, indicated that this was not the case. Rather, failure was due to the destruction of the radial and thrust bearings by high temperature. This result was surprising since turbine motors had been used during the initial drilling of the State 2-14 well where greater temperatures were encountered.

The IADC reports showed that both mud pumps were run at 110 strokes per minute which implies approximately 550 gpm (35 l/s) flow. This should be ample to run the turbine motors.

However, subsequent examination of the computer printout sheets by the mud logging firm showed that the average pump speed during the first turbine motor run was about 100 strokes per minute for 250 gpm (16 l/s) mud flow, and the average pump speed was about 120 strokes per minute producing 300 gpm (19 l/s) during the second turbine motor run. This was not enough flow to start the turbine motors; it is barely enough (at 300 gpm or 19 l/s) to sustain motor operation once started.

Conclusions. The PDMs did not operate because excessive temperature caused the elastomer stators to disintegrate.

The failure of the turbine motors was due to insufficient fluid flow to operate and cool the motors. Inadequate cooling caused failure of the radial and thrust bearings.

Failure of the whipstock was due to weak cement and to not taking sufficient pains to initiate the sidetrack properly.

2.2.4 Bit Record

A total of 10 bits were used in reworking the well. Five mill-tooth and five button bits were used.

Three of the mill-tooth bits were 8-1/2 in. diameter used on the mud motors for sidetracking the hole and for drilling cement and cleaning out fill. Two 6-in. diameter mill tooth bits were used for drilling the pilot hole while attempting to sidetrack using a whipstock.

The five button bits were used in attempts to drill a new hole. The original hole was drilled primarily with API 537 (medium soft) bits which showed wear on the cone, indicating that a longer tooth (soft) bit might be used with a resulting increase in penetration rates. The button bits used for the rework were API 437 (soft formation) bits. Because little new hole was drilled (and most of that was on junk), no conclusions can be made concerning the suitability of the soft formation bits.

A copy of the bit record is provided in Appendix B.

2.2.5 Drilling Fluids Program

Fresh water was used primarily for cooling the well, and brine from the brine pond with density of 9.2 lbm/gal (1.10 kg/l) was used for killing the well.

A fresh water gel mud with Kenseal was used for drilling. Mud weight and funnel viscosity were maintained at 8.7 lbm/gal (1.04 kg/l) and 38 sec/qt, respectively.

Loss of circulation was not a problem because the mud weight was so low; however, the under-balanced system allowed the well to flow on numerous occasions. The well flow was controlled by bullheading brine down the hole to kill it.

A solids control system similar to that used for the original hole was used to maintain a low weight and solids content of mud.

Mud chillers were used to maintain the return mud well below its flash point.

A recapitulation of the daily mud properties and material usage and the mud engineer's report are furnished in Appendix C.

2.2.6 Short Flow Test

A short flow test was conducted on August 31, 1987, after completion of the rework activities to ensure that State 2-14 could be used as a production well for an injection test planned for the Imperial 1-13 well by INEL.

The State 2-14 well was flowed for 12 hours averaging 569,000 lbm/hr of total flow (steam and liquid combined). The maximum production rate was 1,222,000 lbm/hr during the last 32 minutes of the test when the throttling valve was fully open.

A more detailed report of the short flow test of the State 2-14 well is included as Appendix D.

Section 3

CONSTRUCTION OF FLOW TEST FACILITY

3.1 DESCRIPTION OF FLOW TEST FACILITY

The flow test facility was originally designed, constructed, and used in 1982 to test a geothermal well at the South Brawley resource, which also produces hot, highly saline brine. The flow test equipment was subsequently disassembled, moved, reassembled, and used to test two wells in the Niland resource area. After the tests at Niland, the equipment was again disassembled, moved, and stored at the DOE facility at East Mesa.

Construction of the flow test facility for testing the State 2-14 well was done in two parts. The first part was in the Fall of 1987; the second in May 1988.

3.1.1 Flow Test Facility for Injection Test

In September 1987, when construction of the flow test facility began, the objective of the flow test was an injection test of the nearby Imperial 1-13 well. For this test, the State 2-14 well would operate at virtually a constant and uninterrupted flow rate to furnish brine for injection into the Imperial well. Figure 3-1 shows a simplified flow diagram of the well test facility for the injection test that was planned.

The two-phase geothermal fluid produced by the State 2-14 well flows to the high pressure separator, V-1. Startup piping is provided for bypassing the separator and sending the flow to the brine pond through either the vent-silencer, V-4, the atmospheric flash tank, V-3, or directly to the brine pond through the blooie line.

The normal flow path admits the two-phase flow stream to the separator where the liquid and steam are disengaged due to centrifugal force. The liquid entering the separator spirals downward along the walls. The brine liquid exits the separator from the bottom, with the steam leaving through the top.

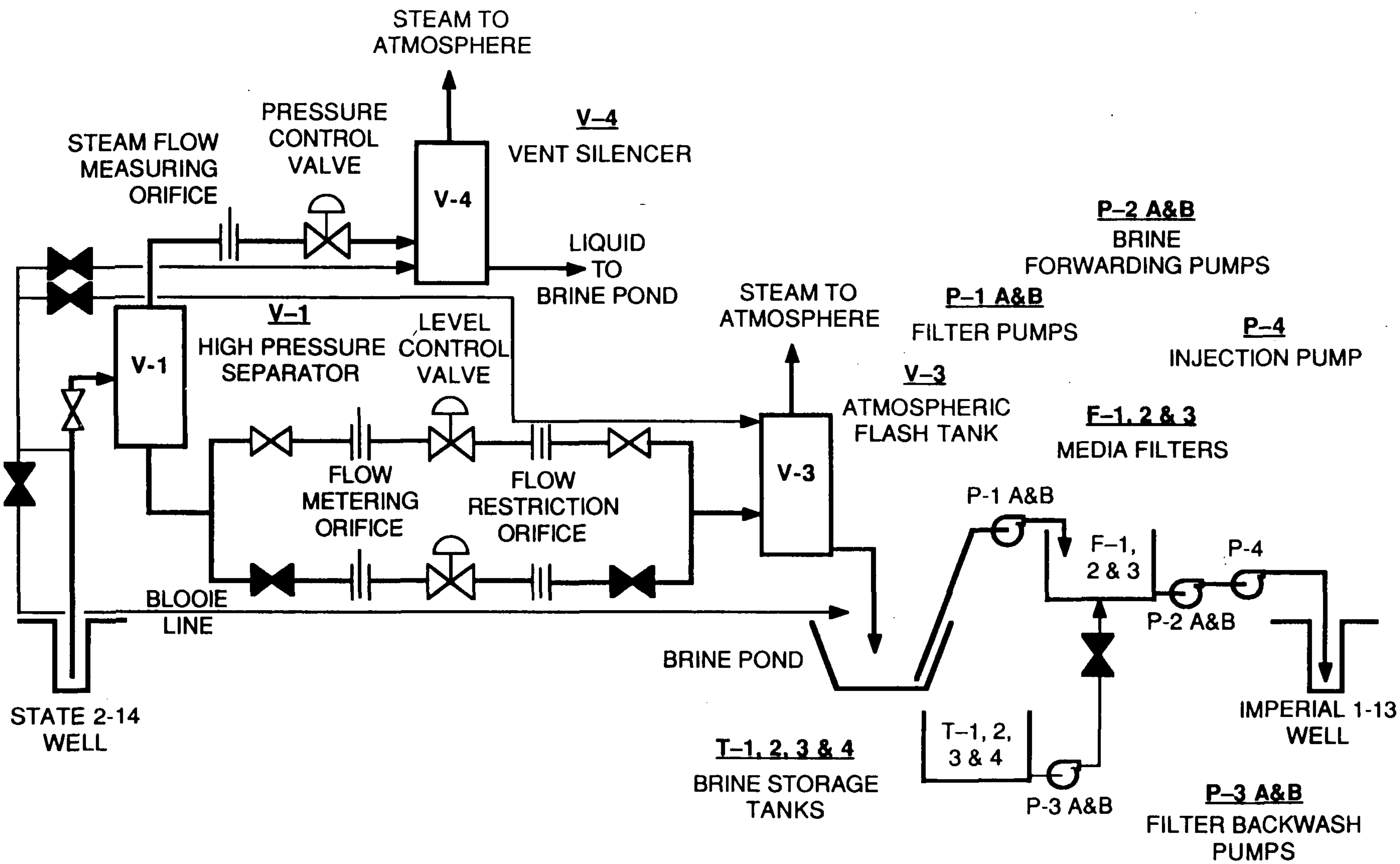


Figure 3-1 Simplified Flow Diagram of Test Facility for an Injection Test

The steam flow rate is measured using an orifice meter. Then the pressure is reduced by a pressure control valve that regulates the pressure in the separator. The steam is vented to the atmosphere through the vent silencer, V-4.

The separated brine exiting from the bottom of the separator flows through one of two parallel measuring loops. Each of the two loops contains an orifice meter, a level control valve, and a flow restriction orifice. Two loops are provided for reliability because of the high potential for scaling in the brine flow line from the separator. Use of a redundant control loop allows continuing a flow test while inspecting and performing maintenance work on one of the loops. The low pressure brine leaving the flow restriction orifice is a mixture of steam and liquid which flows to the atmospheric flash tank, V-3.

The atmospheric flash tank separates the two phases that enter from the flow restriction orifice. The steam escapes to the atmosphere through the top of the flash tank. The liquid exits from the bottom and flows into a brine pond.

The brine pond serves two functions in the process. First, it provides surge capacity (i.e., storage) so that the production rate of the State 2-14 well and the injection rate into the Imperial 1-13 well are not required to be exactly equal at all times. Second, it provides residence time for sludge to precipitate from the brine. A vertical, reinforced-polyethylene divider curtain in the brine pond forces the brine to flow to the south end of the pond and then back to the north end as it travels from the pond inlet to the pump suction.

Liquid from the brine pond is pumped to media filters, F-1, 2, and 3, by one of the two filter pumps, P-1 A or B. The media filters remove solid particles to condition the brine for injection. Two full-capacity filter pumps are installed to provide high reliability.

The media filters are cleaned by backwashing with filtered brine. The storage tanks, T-1, 2, 3, and 4, store filtered brine. One of the two backwash pumps, P-3 A or B, forces the filtered brine up through a media filter, opposite to the normal direction of flow. The backwash liquid carrying the solids removed from the filters flows back to the brine pond through a gravity overflow line. Two full-capacity backwash pumps are provided for high reliability. Any one of the three media filters can be isolated for backwashing while the other two remain in service.

The filtered brine from the media filters is pumped to the Imperial 1-13 well using one of the transfer pumps, P-2 A or B, and an injection pump, P-4, in series. Two full-capacity transfer pumps are provided for high reliability.

The initial phase of construction in October and early November 1987 was aimed at building a flow test facility capable of supplying filtered brine for an injection test.

3.1.2 Flow Test Facility for Production Test

Construction of the flow test facility was suspended in November 1987 due to uncertainty about funding for an injection test. By May 1988, a production-type test of the deep reservoir became the test objective replacing the injection test. The main differences in configuration of the flow test facility for the two tests are discussed below.

Figure 3-2 shows a simplified flow diagram of the well test facility for a production test of the State 2-14 well and the reservoir that it taps.

A hand-operated valve to throttle the flow was installed in the two-phase flow line between the State 2-14 well and the high pressure separator. This valve allows operating with wellhead pressure greater than the pressure in the separator. Thus, wellhead pressure could safely exceed the allowable operating pressure of the separator (500 psig or 3.45 MPa); this condition is most likely when adjusting the system for a low production flow rate. The throttling valve also allows use of low separator pressure at high well flow rate. This helps minimize carryover of liquid droplets in the steam leaving the atmospheric flash tank; relatively low enthalpy and low flow rate of brine from the separator (due to low operating pressure in the separator) limit the steam flow rate from the atmospheric flash tank.

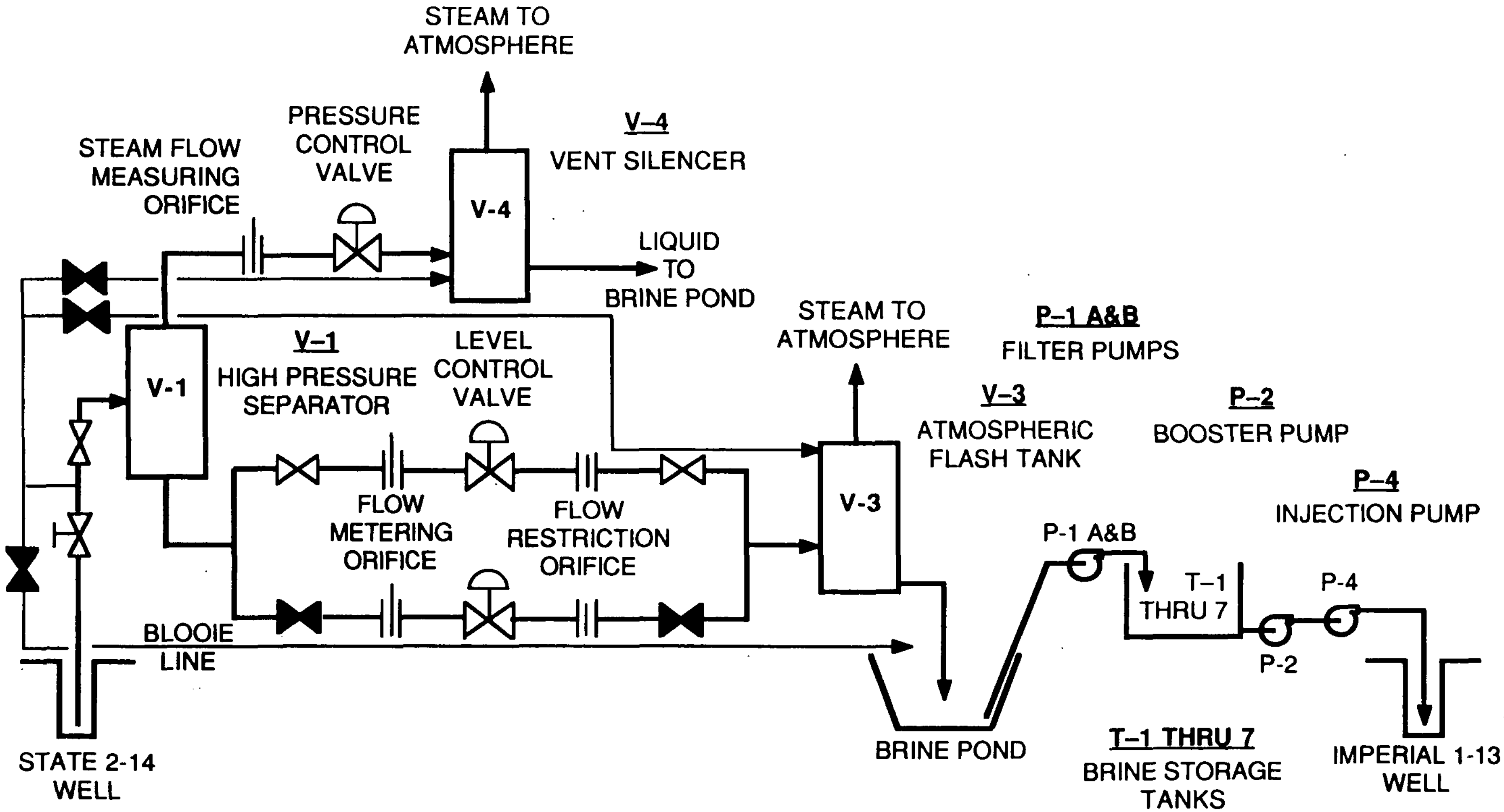


Figure 3-2 Simplified Flow Diagram of Test Facility for a Production Test

The two sets of metering and restriction orifices downstream of the separator were sized to handle the complete range of expected flow rates by switching from one loop to the other without disassembling either loop to insert different orifice plates. For an injection test using constant flow rate, the two sets of orifices would be equal size, designed for the nominal flow rate, to provide an operating loop plus an installed standby loop.

Downstream of the brine pond, several changes were made.

First, the use of media filters was eliminated. A Kennecott evaluation indicated that the Imperial 1-13 well could be used for injecting unfiltered brine during a 30-day test without undue hazard from plugging. Other resource developers have successfully injected unfiltered brine into the same strata without plugging.

The seven 500-bbl capacity tanks that had been installed to serve as media filters and brine storage tanks were reconnected in parallel. This provides a region with low brine velocity for sludge to settle. Thus, it serves as a safeguard against plugging the injection well with sludge inadvertently entrained in the brine pumped from the brine pond.

For a production test, pump redundancy was limited to the filter pumps that transfer brine from the brine pond to the brine storage tanks. Two full-capacity filter pumps were provided for reliability. One booster pump and one injection pump were installed to inject brine into the Imperial 1-13 well. The filter backwash pumps, which were needed for backwashing the media filters, were eliminated.

3.2 CONSTRUCTION

3.2.1 Construction in Fall 1987

Figure 3–3 shows a plot plan of the flow test facility as planned for the Fall of 1987.

The existing brine pond, two-phase flow line, and vent silencer were used. The remainder of the flow test equipment was installed at the north end of the brine pond.

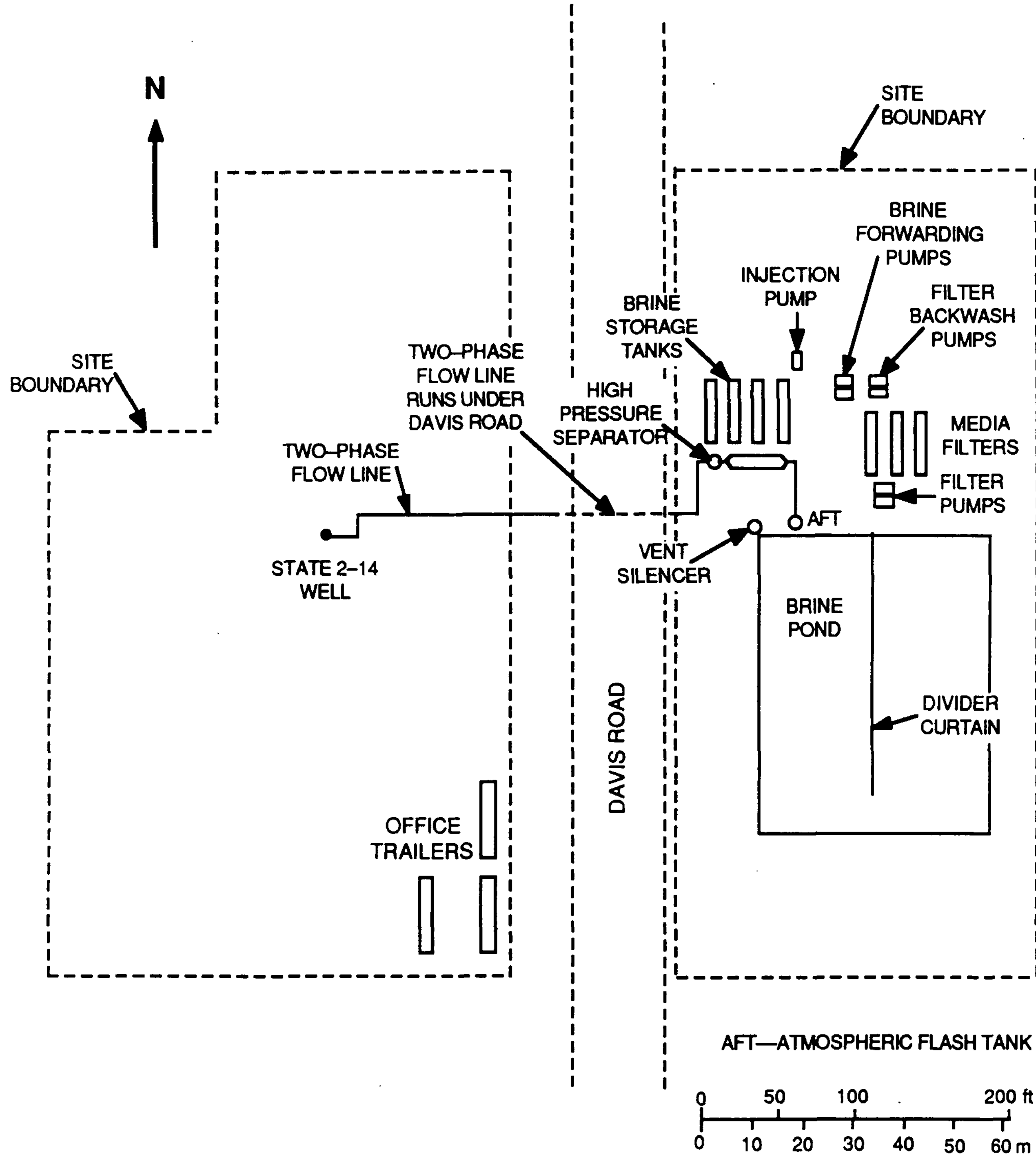


Figure 3-3 Plot Plan of Test Facility for Injection Flow Test

Site Preparation. The soil in the area where the flow test facility was installed consists of sand and clay loam. The water table is 3 to 4 ft (about 1 m) below grade during dry periods, and it may be virtually at grade when the Salton Sea level is high.

The foundation for the high pressure separator was excavated to a depth of 12 in. (30 cm) and filled with rock, covered with 3 in. (8 cm) of soil, and compacted.

For the other equipment, no foundations were needed. The vessels were set on the ground after clearing the sparse vegetation from the particular locations for the equipment.

A new entrance to the area was established to provide better access during inclement weather.

Initial Condition of Vessels, Piping, and Instruments. The high pressure separator was coated with rust and other corrosion products on the inside. On the outside, the insulation sheathing was crumpled and dented, but the insulation was in place. The supporting skirt was coated with rust over about one-third of its surface area. The platform near the top of the high pressure separator was bent so badly that it was virtually destroyed. The high pressure separator is the only pressure vessel in the test facility, and it was hydrostatically tested to 1,200 psig (8.3 MPa) before it was moved from the storage area. This demonstrated the structural integrity of the separator for pressures in excess of the design test pressure. The brine outlet pipe elbow from the separator was noticeably thinned from erosion during previous use, but ultrasonic inspection confirmed that enough steel remained for safe use at the design operating pressure of 500 psig (3.4 MPa).

The atmospheric flash tank and the vent-silencer were coated inside and out with rust from previous use and storage. The tanks for media filters and brine storage were covered with rust on the inside, but the paint on the outside had only occasional areas of rust showing. The amount of material removed from these open-top vessels by corrosion did not jeopardize their use for atmospheric pressure operation.

The major piping was badly rusted and corroded; some of it was also coated with scale on the inside. None of the valves were operational. Many of the valve handles and stems were broken. Numerous flange connecting bolts were galled and had to be replaced. Some of the sample ports and pressure taps had been seal-welded, and due to corrosion, many of the remainder were virtually without any thread to withstand operating pressures.

The instrumentation was in poor shape. The flow and level recorders were in such bad shape that renting replacements for the flow test was less expensive than reconditioning. The flow orifices were either missing or had to be replaced due to erosion, corrosion, or bending. Most of the temperature and pressure indicators were in storage, but good instrumentation practice requires that they be calibrated before use during the flow test.

Reconditioning. All the valves were reconditioned before installation. The four 12-in. valves that isolate the measurement loops downstream of the separator were sent to a local valve shop for replacement of stems, handles, and packing; the internals were sandblasted as part of this reconditioning. All valves were disassembled and cleaned; defective parts were either replaced or hand refurbished. The valves that were beyond cost-effective reconditioning were replaced.

Installation. The high pressure separator was set in place on a spider made of 10-in. pipe to spread the load over a large bearing surface; the spider was filled with concrete for ballast. The other vessels were set in place on the ground with no foundations. Because the pumps are rental items, they were not set in place at this time.

Piping spool assemblies that were usable were reconnected in the previous configuration. All flanges were broken open, cleaned, regasketed, and reassembled. New piping sections as required were fabricated and installed. All piping was installed on temporary wooden-block supports.

The instruments were stored rather than installed. At this time in early November 1987, projection of the start-date indicated that mid-January 1988 would be the earliest date for starting a flow test. With a period of at least two months before start of testing, instrument storage was better than having the instruments installed and exposed to the weather.

The construction was interrupted in early November 1987 by mutual agreement of DOE, Bechtel, and Kennecott. Construction activity was shut down and all personnel left the site awaiting restart of flow test preparation.

3.2.2 Construction in May 1988

Construction of the flow test facility resumed on May 1, 1988 for a well/reservoir production test instead of an injection test. The scheduled start date for the well flow test was June 1, 1988. Figure 3-2 shows a simplified flow diagram for the production test, and Figure 3-4 shows the plot plan. The performance of the hydrostatic leak tests is such a significant milestone that construction activities may be classified for discussion as before or after hydrostatic test as follows:

- Before hydrostatic leak tests

  Review of the facility during the period from November 1987 to May 1988 indicated that the elbows in the existing two-phase flow line could erode so rapidly that a 30-day test would be jeopardized. Such rapid erosion has been observed with some of the other geothermal wells in the Imperial Valley. Therefore, eight elbows in the 10-in. two-phase flow line were removed and Tee's, with one of the straight connections capped, were installed. By orienting the Tee's with the remaining straight connection in the direction of incoming flow, the capped connection serves as a liquid-filled cushion to turn the flow 90 degrees without eroding the walls of the piping.

  The four 12-in. gate valves that isolate the measuring loops downstream of the separator were initially installed with the valve stems vertical. Review and discussion of this orientation indicated that these large valves should be oriented with the stems at about 45 degrees from horizontal to allow manual operation. This orientation allows a person to use his weight as part of the turning force. With such large valves, this weight component is often required unless a mechanical operator is installed on the valve. Therefore, the metering loops were disassembled, and the four large valves reoriented.

  A 10-in. valve for throttling the two-phase flow was installed in the existing 10-in. two-phase flow line from the State 2-14 well to the high pressure separator.

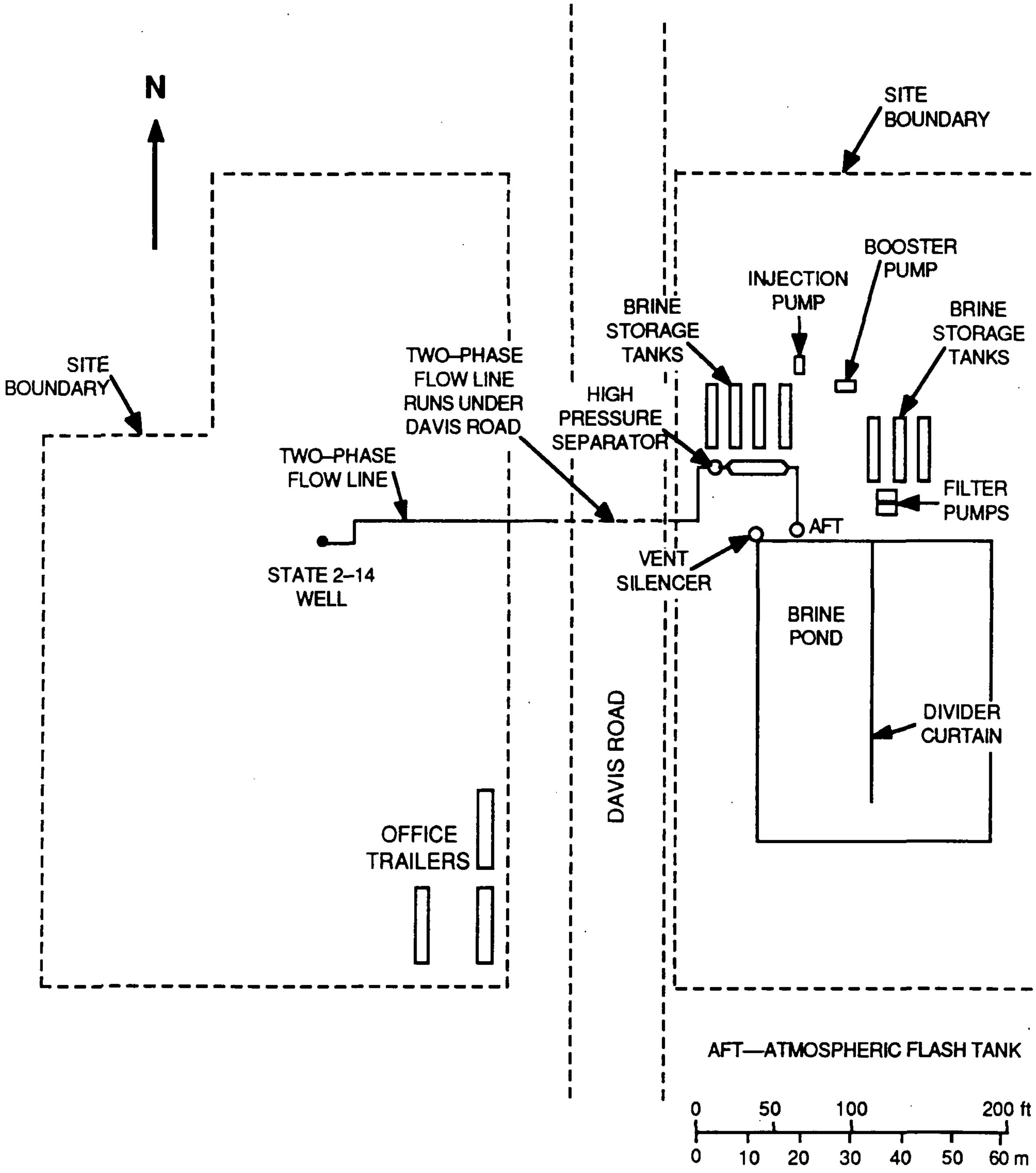


Figure 3-4 Plot Plan of Test Facility for Production Flow Test

The wooden blocks that were used as temporary pipe supports during construction in Fall 1987 were replaced with more substantial supports, typically a Tee-shaped member fabricated of pipe held in place by a poured-in-place concrete base.

The railing for the platform near the top of the high-pressure separator was repaired to make installation or operation activities safer.

Approximately one hundred feet of 6-in. piping was connected from the injection pump location to the existing injection line that leads to the Imperial 1-13 well. The Imperial well is approximately one-half mile straight north of the well flow test facility.

A fresh-water supply was installed consisting of a pump driven by a stationary engine and a 4-in. diameter temporary pipeline to draw water from an irrigation canal and transport it to the flow test facility. The fresh-water pipeline was laid on the ground for the 1,700 ft (518 m) distance from the water source to the test facility. Large quantities of fresh water were used before the test for hydrostatic testing, during the test for brine dilution, and after the test for cleaning the equipment.

- <u>Hydrostatic leak tests</u>

  Two hydrostatic leak tests were performed on May 25, 1988 to demonstrate the structural integrity of the high pressure vessels and piping in the well flow test facility.

  First, the high pressure separator and the piping from the State 2-14 well to the 12-in. valves at the downstream end of the measuring loops were qualified for operating pressures up to 500 psig (3.4 MPa) at operating temperatures to 470 ^{O}F (243 ^{O}C). The actual hydrostatic test pressure at ambient temperature was 900 psig (6.2 MPa).

  After the hydrostatic test above was concluded, the throttling valve in the two-phase flow line was closed, the high pressure separator and the piping downstream of the throttling valve were vented, and the two-phase flow line upstream of the throttling valve was pressurized further to qualify it for operation to its design pressure of 700 psig (4.8 MPa) at temperatures to 500 ^{O}F (260 ^{O}C). The actual hydrostatic test pressure was 1260 psig (8.7 MPa).

- <u>After hydrostatic leak tests</u>

  After the hydrostatic leak test, a rupture disk rated for 590 psig (4.1 MPa) was installed to limit the pressure in the high pressure separator.

  The calibration and installation of the flow test instrumentation and controls was completed, and the compressed air system to operate the controls was installed.

Since media filters were not used during the production well flow test, the seven 500-bbl (80 m^3) tanks ("Baker tanks") that were to be the media filters and brine storage tanks were connected in parallel. In this configuration, the filter pumps lift brine from the brine pond to the brine storage tanks, and the booster pump takes suction from them. A gravity overflow line was installed from the brine storage tanks to the brine pond so that the tanks could not be overfilled.

The divider curtain was installed in the brine pond. The divider curtain was made of 6-mil reinforced polyethylene. Heavy scrap steel cable was attached as weight to hold the bottom edge along the bottom of the pond. The top was supported with a cable anchored at one end and attached to a hand-operated winch at the other to adjust the tension.

The pumps were rented with a diesel engine to drive each pump. Each pump/engine combination was attached to a trailer to facilitate transportation. Each pump was connected with reinforced hose on both the intake and the outlet. The pumps were the last major equipment items installed before the test began.

Well flow from the State 2-14 well began on June 1, 1988. At the start, flow bypassed the separator and entered the brine pond first through the blooie line and later through the atmospheric flash tank. Installation of pumps and piping to transfer brine from the pond to the brine storage tanks was completed on June 3. The next day, installation of the booster pump on the injection line was completed, and injection began. On June 6, two-phase flow was admitted to the high pressure separator. This concluded the construction phase of the well flow test.

Section 4

FLOW TEST

This section discusses the flow test of the State 2-14 well that was conducted in June 1988, and addresses the scientific research projects that accompanied the flow test.

The objectives of the flow test were to:

- Demonstrate the long-term producibility of the well and reservoir
- Obtain the production data and downhole measurements needed to perform a reservoir engineering analysis of the well performance and the near-well reservoir properties
- Obtain samples of the brine, steam, and noncondensible gases for chemical analyses to characterize the reservoir fluid, calculate its physical and thermodynamic properties, and analyze for changes in composition associated with flow rate changes
- Measure the preflash temperature of the brine and obtain other data to calculate the enthalpy of the fluid produced and the rate of energy production for the well
- *Provide an opportunity for other experimenters to perform tests in* conjunction with the flow test

Specifically excluded from the scope of the June 1988 flow test were measurements of well–to–well pressure response, calculation of areal reservoir properties, and estimation of reservoir size.

4.1 FLOW TEST

4.1.1 Test Plan

The flow test of the State 2-14 well in June was originally planned as a 30-day step-rate test with three rate steps scheduled as follows and as shown in Figure 4-1:

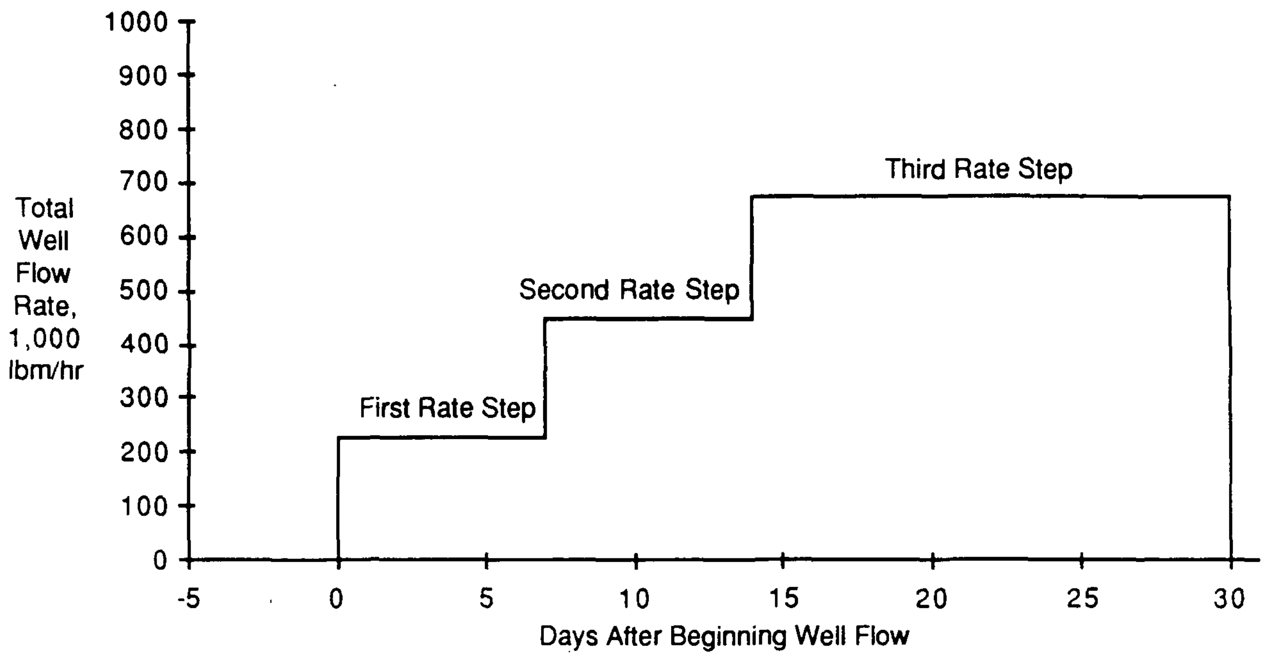


Figure 4-1 Planned Schedule for 30-Day Flow Test

	Planned Duration (days)	Planned Flow Rate (lbm/hr total mass)
First rate step	7	200,000 to 250,000
Second rate step	7	400,000 to 500,000
Third rate step	16	600,000 to 750,000

1,000 lbm/hr = 454 kg/hr

Three previous short-duration flow tests, during and after drilling, were conducted with a simple test facility that held the residual brine in a brine pond without injecting any of it. These tests were limited to 54, 37, and 12 hours' duration by the capacity of the brine pond. To perform a longer-term (i.e., 30-day) flow test, the more elaborate test facility described in Section 3 is required. This facility provides the necessary capability of brine injection and the advantages of steam/brine separation for separate metering and sampling of the two phases.

The step-rate test is a standard reservoir engineering method for obtaining the downhole pressure response data for determining reservoir properties and defining a deliverability curve (i.e., graph of production rate versus wellhead pressure). The planned duration of each rate step was estimated to be adequate for the well to reach stable operation with respect to flow rate, pressure, and chemistry. The schedule of increasing flow rates also facilitated operation of the flow test facility by allowing a step-wise approach to the higher flow rates.

A total of five downhole pressure and temperature surveys were planned to acquire data for reservoir engineering analysis and for characterization of the brine before flash. Production logs, which would normally be run to delineate and quantify zones of inflow, were not planned because the mechanical condition of the well precluded running logging tools deeper than 5,500 ft (1,676 m).

The schedule for flow rates and durations of the steps was revised during the first week of the test for the following reasons:

- The budget could not support 30 days of testing.
- The State 2-14 well was confirmed as a high productivity well, and its flow conditions stabilized within hours after a rate change. For purposes of reservoir engineering analysis and for defining the deliverability characteristic of the well, shorter duration flow steps would suffice.
- The well is clearly capable of high flow rates, and the initial rate step was about one-half the rate that was planned due to limitations of the test facility early in the test. To define the useful range of flow rates for the well, three additional rate steps (for a total of four) were considered necessary.
- The maximum flow rate of the well would be limited by the capacity of the test facility. Therefore, the full flow rate potential of the well would be determined by a maximum rate flow test directly to the brine pond. To accomplish this without compromising the reservoir and well performance analyses, a separate full flow rate test was scheduled following the four rate steps and a shutin period. Because brine production would outrun the injection rate, the test at full flow rate was to last only a few hours as determined by the maximum injection rate and the brine pond capacity.

The revised schedule for the flow test is summarized below and is shown in Figure 4-2:

	Planned Duration (days)	Planned Flow Rate (lbm/hr total mass)
First rate step	7	125,000
Second rate step	3	250,000
Third rate step	3	450,000 to 500,000
Fourth rate step	6	650,000 to 750,000
Shutin to monitor pressure buildup	2	Zero
Test at full flow	<1	Maximum flow rate probably >1,000,000

1,000 lbm/hr = 454 kg/hr

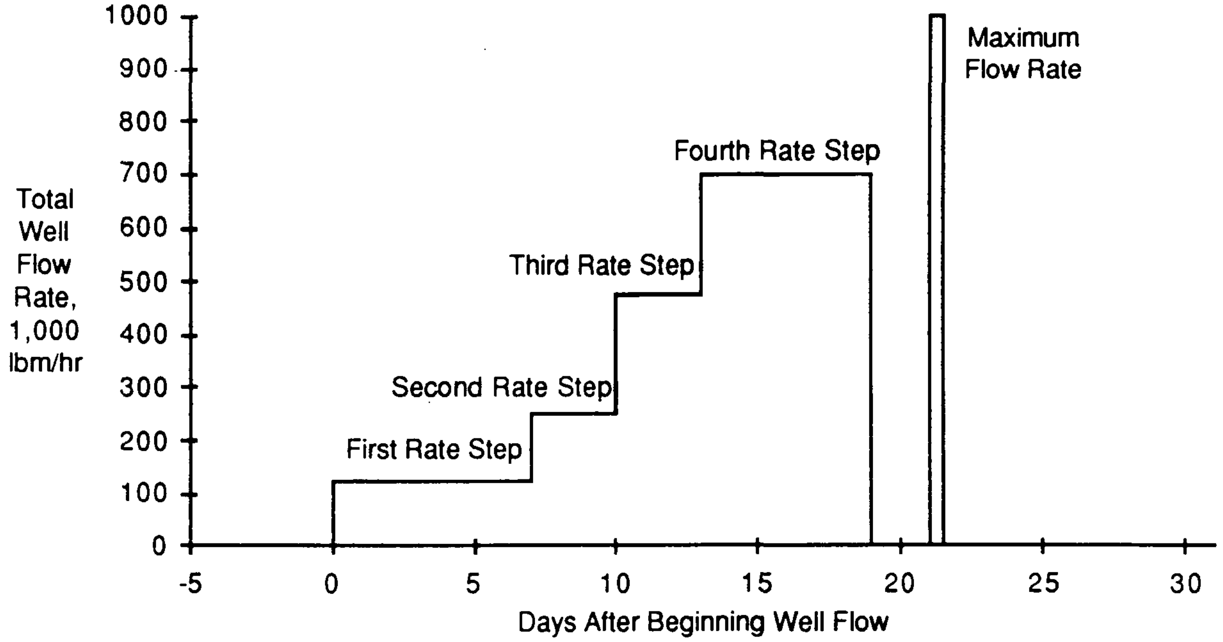


Figure 4-2 Revised Schedule for Flow Test

4.1.2 Well and Reservoir Test Results

Test Operating Conditions: Figure 4-3 shows the flow rate during the test. In this plot, the flow rate during each step is smoothed; that is, the flow rate is averaged during each step to focus on the flow rate trends. Figure 4-4 shows the wellhead temperature and pressure (smoothed) during the test. Detailed plots of the flow rate, wellhead temperature, and wellhead pressure at 2 hour intervals are given in the well test engineering report (Appendix F).

The test was planned and conducted as a step-rate test, but parts of it deviated from the ideal of long periods with constant flow rate. Although the well itself showed no appreciable pressure decline, there was a tendency for the flow rate to drift downward, probably because of scale deposition in the throttle valve. Occasional adjustments of the throttle valve were required to achieve the desired flow rate. This commonly occurrs in well testing in the Salton Sea field and did not significantly affect the results.

The highest rate of 768,000 lbm/hr (348,000 kg/hr) was maintained for less than 1 hour because of a separator control problem. Therefore, the deliverability data at that rate do not represent a fully stabilized condition. Nevertheless, the results are adequate to achieve the reservoir engineering test objectives.

The well was initially produced at about 125,000 lbm/hr (57,000 kg/hr), significantly lower than the planned initial rate of 200,000 to 250,000 lbm/hr (91,000 to 113,000 kg/hr). This lower flow rate was used because the residual brine had to be retained in the brine pond until the injection system was completed on June 4. Ideally, test startup would have waited for completion of the injection system, but budgetary and schedule considerations necessitated the June 1 start.

Once the injection system was operational, the production rate was held at about 125,000 lbm/hr (57,000 kg/hr) until June 8, when the separator was placed in service and direct flow measurements of the separated steam and brine were possible.

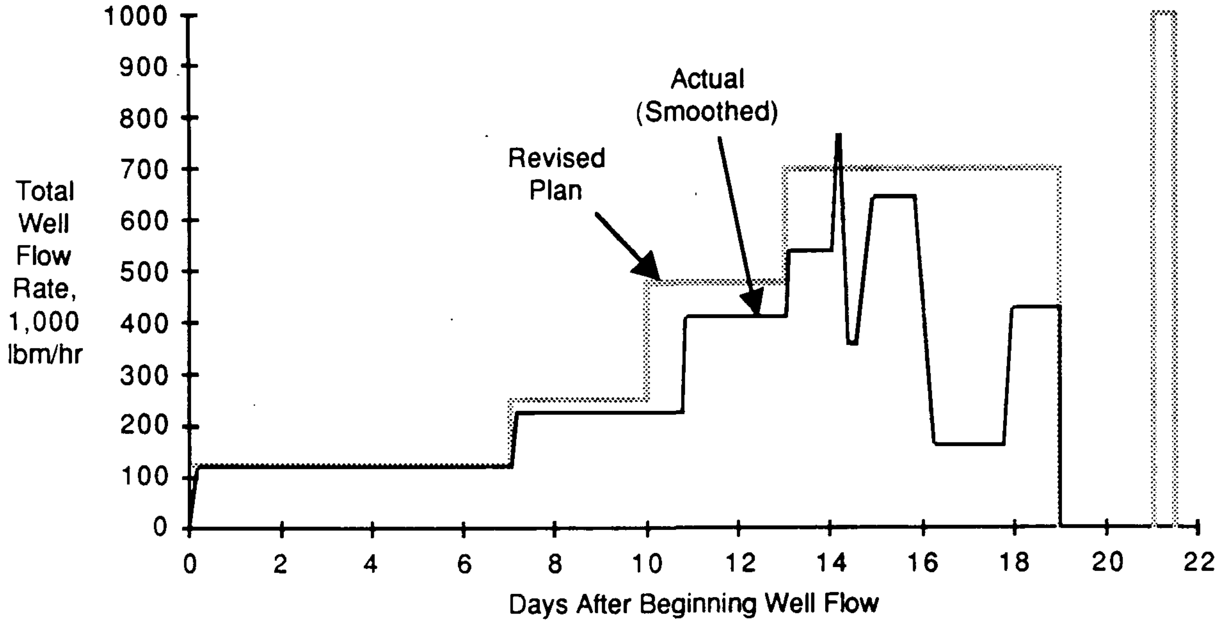


Figure 4-3 Total Well Flow Rate

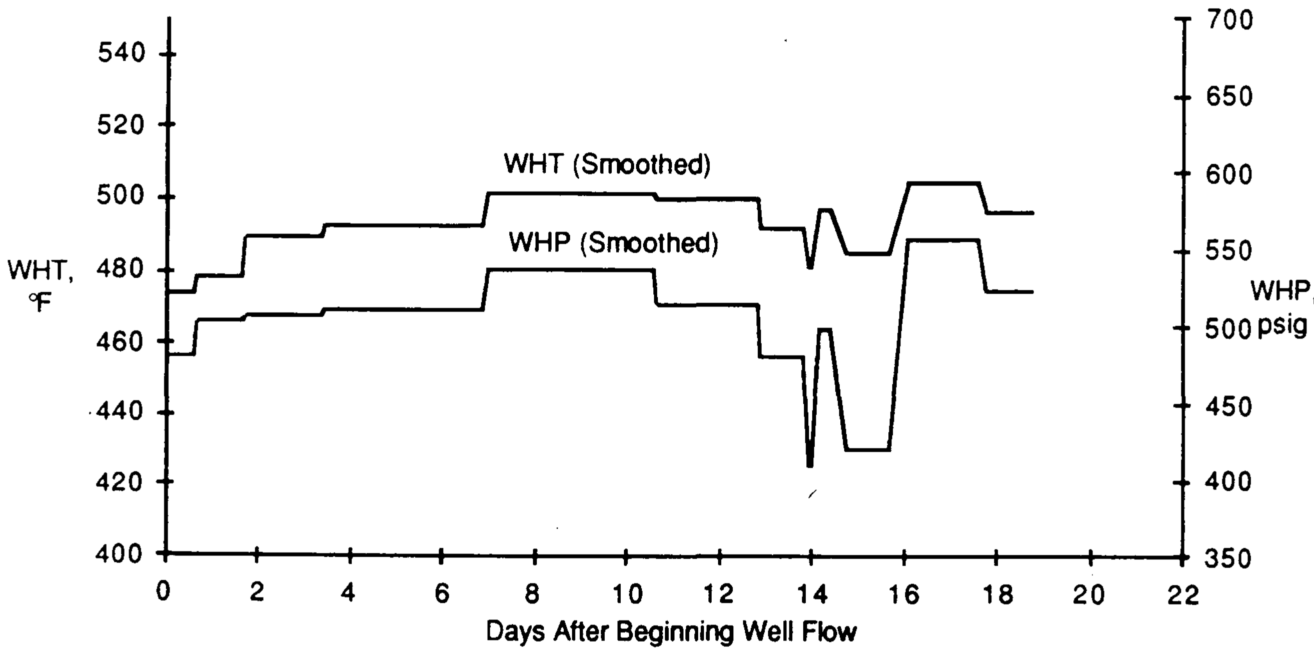


Figure 4-4 Wellhead Temperature and Pressure

Late on June 8, the flow rate was increased to 250,000 lbm/hr (113,000 kg/hr), and the durations of the succeeding rate steps were shortened as indicated in the revised test schedule.

Downhole temperature and pressure profile surveys were conducted on June 5, 12, 14, and 20. These surveys measured stabilized flowing pressure at the 5,000 ft (1,524 m) datum at various flow rates to define the well inflow performance. They also measured flowing temperature and pressure profiles between the surface and 5,000 ft (1,524 m) to provide data for thermodynamic flash calculations and to establish whether a relationship exists between brine temperature and flow rate.

Pressure drawdown was recorded as the flow rate was increased on June 12 and 14, and the pressure buildup was recorded for 44 hours after the shutin on June 20. The data from these pressure response measurements are used to calculate near-well reservoir properties.

Typically, a flow test would involve a static downhole temperature and pressure survey to establish equilibrium shutin conditions before the test. This was not done immediately prior to the June 1988 flow test because 1) a suitable static survey was run in November 1987 and 2) brine in the wellbore had been displaced with fresh water in April 1988, distorting any static downhole pressure measurements.

Well Performance. Flow rates and wellhead pressure measurements were used to plot a deliverability curve and calculate deliverability at different wellhead pressures. Pressure transients measured downhole during step rate changes were used to plot a productivity curve and calculate the productivity index.

Deliverability. Figure 4-5 shows the deliverability curve for the State 2-14 well. The following points should be noted about this plot:

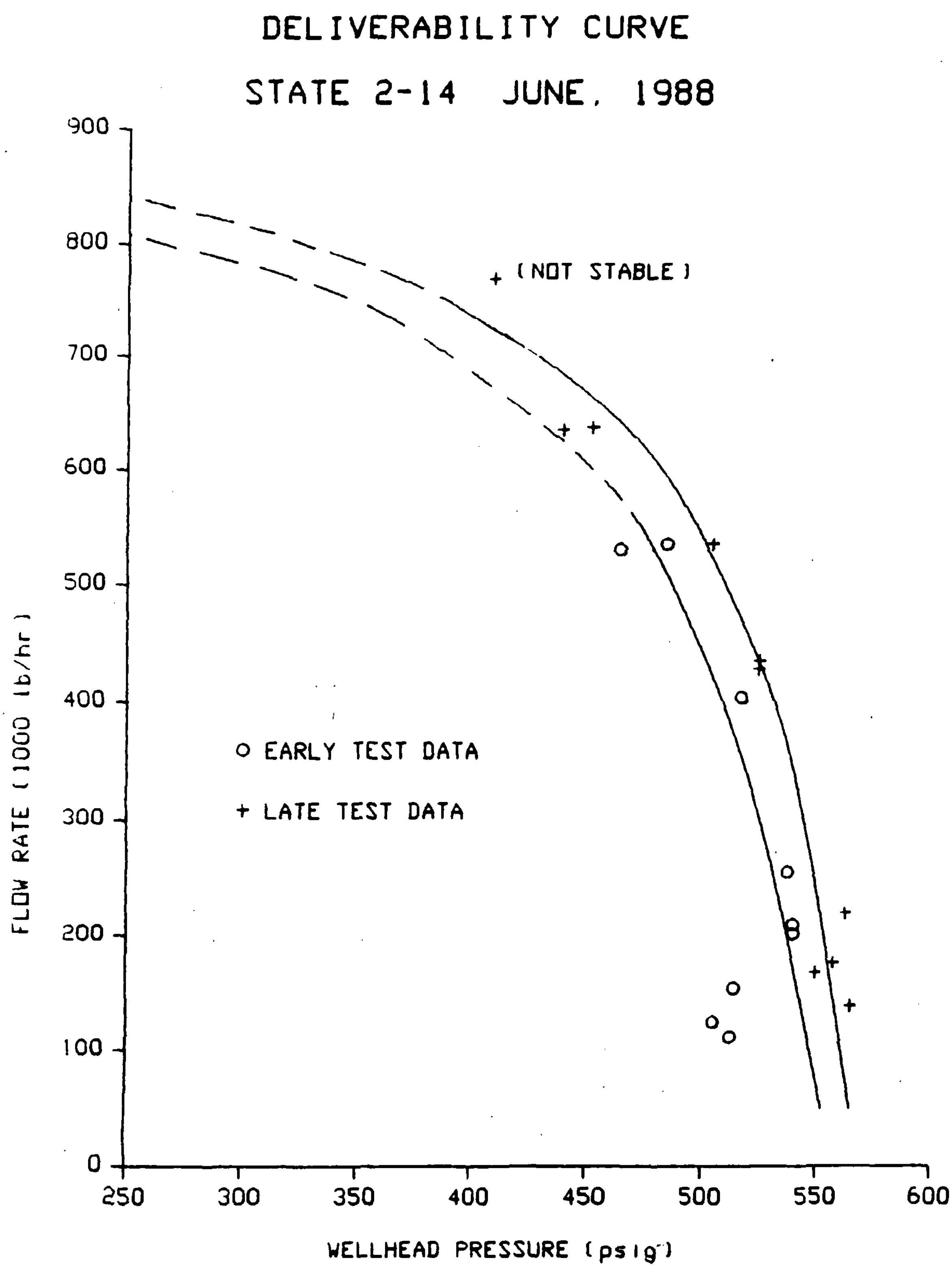


Figure 4-5 Deliverability Curve

- The well was not tested at rates high enough to determine the maximum flow rate at typical commercial operating wellhead pressures. The dashed line represents the shape of the projected curve to lower wellhead pressures. For example, about 840,000 lbm/hr (381,000 kg/hr) could be produced at 250 psig (1,724 kPa) wellhead pressure.
- The increased well deliverability observed later in the test suggests that the well improved during the course of the test. It is likely that flowing the well at higher rates may have cleaned drilling solids from the reservoir rock and also may have opened additional flow paths unavailable at the start of the test.
- At low flow rates, deliverability curves often show a curve toward the origin just before the lowest sustainable flow rate. Points on this curve for low flow rates at the beginning of the test are more likely representative of the improved wellbore condition noted above.

Productivity. Well productivity was assessed using pressure measurements made in the liquid column at 5,000 ft (1,524 m). This is above the suspected primary entry zone at 6,200 ft (1,890 m). During flow conditions, this should not influence the reliability of either productivity or pressure drawdown measurements because the temperature in the flowing single-phase liquid column is subject to only slight cooling due to heat losses between 6,200 and 5,000 ft (1,890 and 1,524 m).

Figure 4-6 shows flow rate plotted against downhole pressure for three stabilized flow rates. The productivity index of a well is usually defined as the flow rate change per unit change in downhole pressure. An average productivity index of 1,527 lbm/hr per psi (100 kg/hr per kPa) was calculated using these data.

The productivity curve is a straight line through the three points, which would be expected from matrix permeability alone. However, reservoirs in the Salton Sea area typically are extensively fractured but also have significant matrix storage capacity. Because well improvement was noted from other data during the flow test and an available static pressure measurement does not fall on the productivity line, the permeability may actually be affected by fracturing in addition to matrix permeability.

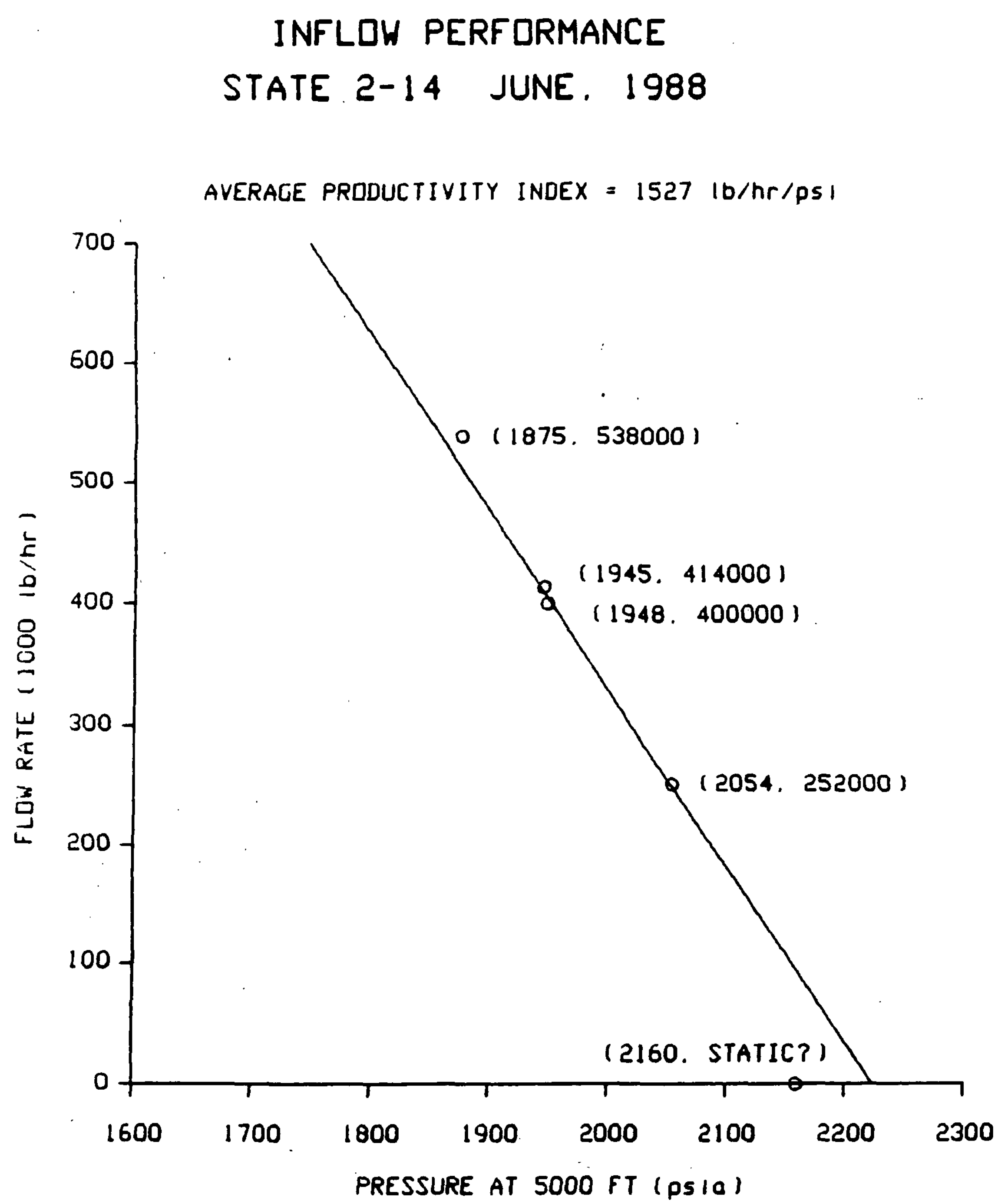


Figure 4-6 Total Well Flow Rate as a Function of Downhole Pressure

Skin. Downhole pressure drop includes not only pressure changes in the reservoir under flowing conditions, but also pressure losses as fluid enters the wellbore (i.e., skin effects) and pressure changes due to differences in the amount of fluid stored in the wellbore (i.e., wellbore storage). For geothermal wells, separating the pressure losses due to skin effects and wellbore storage is almost impossible; therefore, they are generally lumped together and calculated as a "skin factor."

Horner plot analysis of the buildup data yields a calculated skin factor or +23.1. Positive values indicate large pressure losses as the fluid enters the wellbore. These can be caused by wellbore damage, pressure drop across liners or through perforations, partial penetration completions, wellbore storage effects, closing of fractures as pressure decreases, and turbulent flow as fluid enters the wellbore at high rates. For the State 2-14 well, the well probably sustained wellbore damage due to drilling and rework difficulties. However, high flow rates into the wellbore probably contributed to the apparent skin effect also.

Reservoir Performance. Two measurements of drawdown were made during flow rate changes with the following results:

- June 12.
  - Flow rate change: 210,000 to 414,000 lbm/hr (95,000 to 188,000 kg/hr)
  - Initial drawdown: 104.1 psi (718 kPa). Recovered rapidly; then began to draw down again
  - Maximum drawdown: 113.6 psi (783 kPa) at 95 minutes after rate change
  - Recovery: 9.5 psi (66 kPa) over 18.5 hr
- June 14.
  - Flow rate change: 404,000 to 538,000 lbm/hr (183,000 to 244,000 kg/hr)
  - Initial and maximum drawdown: 115.5 psi (796 kPa) at 20 minutes after rate change
  - Recovery: 42 psi (290 kPa) over 14 hr

The pressure recovery following drawdown (when additional drawdown should be expected) is further evidence of well improvement during the flow test. Unfortunately, it makes both drawdown curves impossible to analyze accurately for quantitative reservoir parameters.

At shutin on June 20, the beginning of pressure buildup was not detected at 5,000 ft (1,524 m) until 6 minutes after shutin because of the effects of wellbore storage and the slow rate at which the valves could be closed. The initial buildup was 163 psi (1,124 kPa) within an hour. This was followed by a slow pressure decrease of about 0.05 psi/hr (0.34 kPa/hr) for the next 44 hours. This decrease was probably due to cooling of the fluid between the bottom of the pressure tool and the inflow zone, largely the result of density changes in the wellbore.

The following semiquantitative estimates of reservoir performance factors and skin effect were made using a Horner plot:

- Transmissivity. 233,600 md-ft
- Skin factor. +23.1

The reservoir and well performance estimates indicate that the reservoir has high permeability and adequate storage capacity capable of producing at high flow rates for extended periods. However, because the data were not amenable to boundary analysis, it is not possible to estimate the life of the reservoir or the total production capacity.

Injection Well Performance. The Imperial 1–13 well was used as the injection well throughout the test, with total injected brine of 72.6 million lbm (32.9 million kg).

From the start of injection, the injectivity (flow rate change per unit of pressure change at the wellhead) began to decline. Injectivity at the end of the test was only about 20 percent of the initial value. The progressive injectivity decrease is typical of a well experiencing formation plugging as the result of suspended solids. Brine injection directly from the brine pond without settling in the brine storage tanks occurred, and the concentration of suspended solids in the brine was probably higher during these occasions. However, these episodes alone do not account for the observed plugging. Injection of unfiltered fluid throughout the test probably explains the reduced injectivity.

4.1.3 Brine Chemistry Results

The primary objective of the brine chemistry program was to characterize the brine produced by the State 2-14 well during the flow test in June 1988.

Chemical sampling was supervised by Kennecott, and the primary chemical analyses were conducted for the Electric Power Research Institute (EPRI) by Combustion Engineering, Inc. using the EPRI Mobile Geothermal Chemistry Laboratory that was on site during the flow test.

Three types of sampling events were conducted during the flow test. Signature tests were conducted three times to characterize the chemical and physical characteristics of the total well flow. Tracking tests were performed daily to observe changes in selected properties as a function of time. Special tests were conducted as needed to investigate flow streams or equipment of special interest.

- Signature Tests. The flow test program was planned to stabilize flow in three rate steps. Sampling for signature analyses was conducted at each of the three rate steps as shown in Figure 4-7. In each case, the sampling was done well after the flow had stabilized, usually near the end of each rate step.

  For the signature tests, samples of separated brine and separated steam were collected from the brine and steam outlet lines leaving the high pressure separator. Characterizing the total well flow involved combining measurements of both brine and steam.

  The signature tests included the measurement of 64 separate chemical species. Raw condensate samples were collected to measure pH, conductivity, Eh, dissolved oxygen, anions, and carbonate. Acidified samples (1 percent nitric acid) were collected for analysis of 30 metals by inductively coupled argon plasma spectrophotometry. Trapping solutions were used to trap and measure hydrogen sulfide and carbon dioxide. Noncondensible gases were collected at approximately atmospheric pressure and ambient temperature for analysis by gas chromatography.

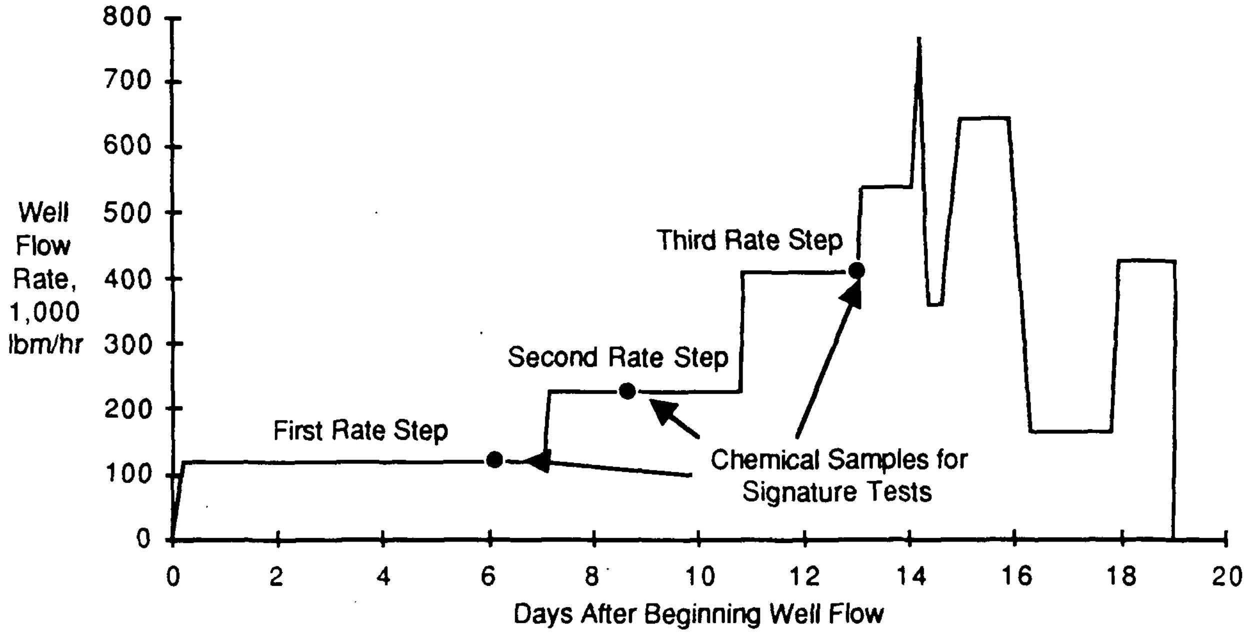


Figure 4-7 Smoothed Flow Curve Showing Times for Collection of Samples for Signature Tests

- Tracking Tests. Tracking samples were collected daily. Raw samples of separated brine were taken for immediate measurement of pH, conductivity, Eh, dissolved oxygen, and chloride. Acidified samples were collected for analysis of 30 metals by inductively coupled argon plasma spectrophotometry.

- Special Tests. Tests for total suspended solids were conducted to provide data to help estimate the rate of sludge accumulation in the brine pond.

This section focuses on the results of the signature and tracking tests for information needed to characterize the brine produced by the State 2-14 well. It presents the results of the signature tests for each flow rate step, explores the reservoir conditions inferred from the brine chemistry, and compares the State 2-14 well with others in the area.

Chemistry Analyses for Each Flow Rate Step. The signature test results were converted to a mass ratio basis (i.e., mg of component per kg of total well flow) by one of the following procedures:

- Noncondensible Gases. The concentration of each noncondensible gas (NCG) component is stated in the laboratory reports as mg of component per kg of steam downstream of the separator. Multiplying these results by the mass fraction of steam (ratio of steam flow rate to total well flow rate) converts them to mg of NCG per kg of total well flow. This assumes that the amount of NCG dissolved in the separated brine is negligible.

- Dissolved Components. The concentration of each dissolved component is stated in the laboratory reports as mg of component per liter of separated brine (cooled to ambient temperature). These results were first converted to mg of component per kg of separated brine by dividing by the density of the separated brine at ambient temperature. A value of 1.2 kg/l was used throughout as an average value for the density of separated brine.

  The concentrations in mg of component per kg of separated brine were then multiplied by the mass fraction of separated brine (ratio of separated brine flow rate to total well flow rate) to convert to mg of component per kg of total well flow.

  This procedure assumes that carryover of dissolved components in the steam is insignificant. Carryover is not zero, but compared to the total, it is extremely small.

Carbonate and sulfide were converted using this procedure even though the flash/separator conditions (i.e., the carbon dioxide and hydrogen sulfide in the steam) could affect the result; therefore, the values stated for these ions should be considered as only rough indications.

- Ammonia. Significant amounts of ammonia appear in both the steam and the separated brine. The ammonia in the total well flow was calculated by totaling the ammonia in each stream. The concentration of ammonia in the total well flow in mg/kg is the sum of the following two quantities:

  - Mg/kg of ammonia in the brine multiplied by the mass ratio of separated brine

  - Mg/kg of ammonia in the steam multiplied by the mass ratio of steam

The brine chemistry results during the three rate steps appear in Table 4-1. The following observations are readily drawn from these results:

- Total dissolved solids (TDS) increased for the second and third rate steps. This variation of TDS is examined and discussed in more detail below.

- Sodium and potassium increased 7 and 12 percent, respectively, from the first to the third rate step, but calcium increased 33 percent.

Noncondensible gas content and composition results appear in Tables 4-2 and 4-3. Noncondensible gas content is rather high. Concentrations of the half-percent magnitude (3,928 to 5,731 mg/kg) reported here would force extensive and probably expensive measures in the construction and operation of a power plant using the brine. Additional testing should confirm these results before design of a power plant to use brine from this well.

Carbon dioxide comprises more than 98 percent of the noncondensible gases; this is commonly the case for geothermal fluids.

Hydrogen sulfide is reported as 22, 2.2, and 6 mg/kg for the three rate steps. Additional testing to quantify the hydrogen sulfide is appropriate before

Table 4–1

Brine Chemistry
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step Concentration in Total Well Flow (mg/kg)	Second Rate Step Concentration in Total Well Flow (mg/kg)	Third Rate Step Concentration in Total Well Flow (mg/kg)
Aluminum	0.140	0.201	0.198
Antimony	0.442	0.661	0.696
Arsenic	5.77	6.49	11.39
Barium	114	72	94
Boron	399	Not reported	Not reported
Cadmium	0.463	0.533	0.443
Calcium	23,128	30,143	30,723
Cobalt	0.032	0.028	0.034
Chromium	0.081	0.019	0.204
Copper	1.60	2.64	3.68
Gold	12.8	11.3	12.0
Iron	1,297	1,314	1,448
Lead	78	73	70
Lithium	157	164	174
Magnesium	14.6	13.7	13.4
Manganese	1,177	1,123	1,132
Mercury	< 0.001	< 0.001	< 0.001
Molybdenum	0.024	0.015	0.020
Nickel	0.018	0.032	0.032
Potassium	13,526	13,152	15,116
Selenium	< 0.001	< 0.001	0.001
Silicon	Not reported	127	117
Silver	0.144	0.166	0.190
Sodium	49,829	52,537	53,151
Strontium	339	326	371
Tin	<0.010	<0.060	<0.060
Titanium	<0.010	<0.010	<0.010
Tungsten	3.01	3.21	3.25
Vanadium	0.266	0.338	0.351
Zinc	421	402	459
Carbonate	Not reported	142	260
Chloride	144,000	149,000	150,000
Sulfate	77	Not reported	Not reported
Sulfide	5	4	65
TDS	235,000	249,000	253,000
NCG, mass %	0.57	0.39	0.40*
Ammonia, mg/kg	375	Not reported	Not reported
Well flow rate, lbm/hr	127,000	227,000	402,000

* From 6/20/88 with 435,000 lbm/hr well flow rate
NCG analysis data not available for third rate step

Table 4–2

Noncondensible Gas Content
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step	Second Rate Step	Sample on 6/20/88*
	Concentration in Total Well Flow (mg/kg)	Concentration in Total Well Flow (mg/kg)	Concentration in Total Well Flow (mg/kg)
Carbon dioxide	5,642	3,897	4,005
Hydrogen	3.1	0.55	0.77
Hydrogen sulfide	22	2.2	6
Nitrogen	8.6	5.5	15
Methane	12.7	7.3	6.0
Other hydrocarbons	43	16	8.86
Total NCG	5,731	3,928	4,041
Well flow rate,lbm/hr	127,000	227,000	435,000

*NCG analysis data not available for third rate step

Table 4–3

Noncondensible Gas Composition
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step	Second Rate Step	Sample on 6/20/88*
	Concentration mass % of NCG	Concentration mass % of NCG	Concentration mass % of NCG
Carbon dioxide	98.44	99.21	99.10
Hydrogen	0.05	0.01	0.02
Hydrogen sulfide	0.38	0.06	0.14
Nitrogen	0.15	0.14	0.38
Methane	0.22	0.18	0.15
Other hydrocarbons	0.75	0.40	0.22
Total NCG	100.00	100.00	100.00
Well flow rate, lbm/hr	127,000	227,000	435,000

*NCG analysis data not available for third rate step application of this brine for power production. This should be done to assess whether and to what degree hydrogen sulfide abatement may be needed.

Reservoir Chemistry. Nine possible production zones were encountered during the drilling process at 2,619 to 3,160; 5,450 to 5,460; 6,110 to 6,130; 6,635 to 6,650; 8,090 to 8,100; 8,580; 8,950; 9,095 to 9,125; and 10,475 ft (798 to 963; 1,661 to 1,664; 1,862 to 1,868; 2,022 to 2,027; 2,466 to 2,469; 2,615; 2,728; 2,772 to 2,781; and 3,193 m). A casing was cemented in place to a depth of 6,000 ft (1,829 m), preventing the two zones at lesser depths from producing. However, with uncemented liner below 6,000 ft (1,829 m), the seven deeper zones are all possible sources of geothermal fluid with composition and temperature different for the various zones.

The TDS concentration and the geothermometers, Na/K, Na/Ca, and Ca/K, were examined for indications that various zones were producing in different proportions as the well flow was varied during the flow test. The results for the June 1988 flow test were compared with similar indicators from the flow test of the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) in December 1985 and the flow test conducted shortly after well completion in March 1986.

Total Dissolved Solids. The TDS concentration is plotted in Figure 4-8 as a function of time for the June 1988 flow test. The TDS data from the three rate steps is supplemented in this plot with estimates of TDS concentration from the tracking tests. The chloride concentration was measured in the tracking tests, and TDS concentration was calculated from the measured chloride content. The ratio of TDS to chloride is virtually constant for highly saline geothermal wells in the Imperial Valley. For the signature test results, this ratio varies from 1.63 to 1.69 for the three rate steps. Therefore, a value of 1.66 was used to estimate TDS for plotting Figure 4-8.

The TDS varied little during the flow test even though the smoothed flow rate varied over a range of 7:1.

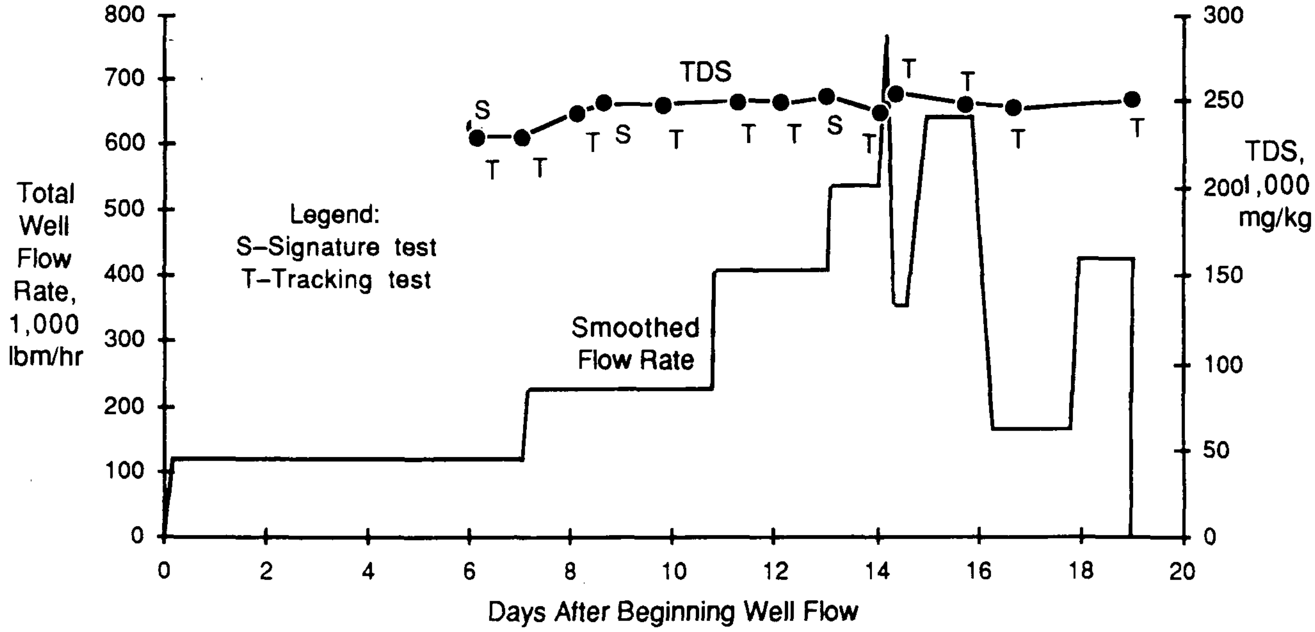


Figure 4-8 Total Dissolved Solids During Flow Test

A slight increase in the TDS concentration apparently occurred as the well flow rate was increased for the second rate step. Initially, the TDS concentration was about 235,000 mg/kg, which increased to about 250,000 mg/kg. No further significant changes were observed after this shift between the first and second rate steps.

Figure 4-9 shows the TDS concentration as a function of instantaneous flow rate at the time a brine sample was taken for chemical analysis. This perspective of the TDS–flow rate information leads to the same conclusion as indicated above. For well flow rate somewhat greater than 100,000 lbm/hr (45,359 kg/hr), the TDS concentration was about 235,000 mg/kg; for flow rates greater than 200,000 lbm/hr (90,718 kg/hr), the TDS concentration was about 250,000 mg/kg.

Geothermometers. Table 4-4 shows the values for the geothermometers, Na/K, Na/Ca, and Ca/K, for the three rates steps and for earlier tests in March 1986 and December 1985.

The short flow test in December 1985 was conducted with the well drilled to a depth of about 6,200 ft (1,890 m), with casing installed and cemented to 6,000 ft (1,829 m). Thus, it was a test of the zones from 6,000 to 6,200 ft (1,829 to 1,890 m), primarily the zone from 6,110 to 6,130 ft (1,862 to 1,868 m).

The short flow test in March 1986 was conducted shortly after completion of the well to a depth of 10,564 ft (3,220 m). At that time, the well had a cemented casing from the surface to a depth of 6,000 ft (1,829 m) and an uncemented liner from 5,748 to 10,148 ft (1,752 to 3,093 m). Thus, any zone from 6,000 ft (1,829 m) to bottomhole could have contributed to the flow.

During the flow test in June 1988, the sodium and potassium increased slightly from the first to the third rate step (sodium: 7 percent; potassium: 12 percent). However, calcium increased by 33 percent. Thus, the Na/Ca and Ca/K ratios changed considerably (–20 and +19 percent, respectively) while the Na/K ratio changes were less dramatic (+8 percent from the first to second rate steps, 4 percent from the first to the third).

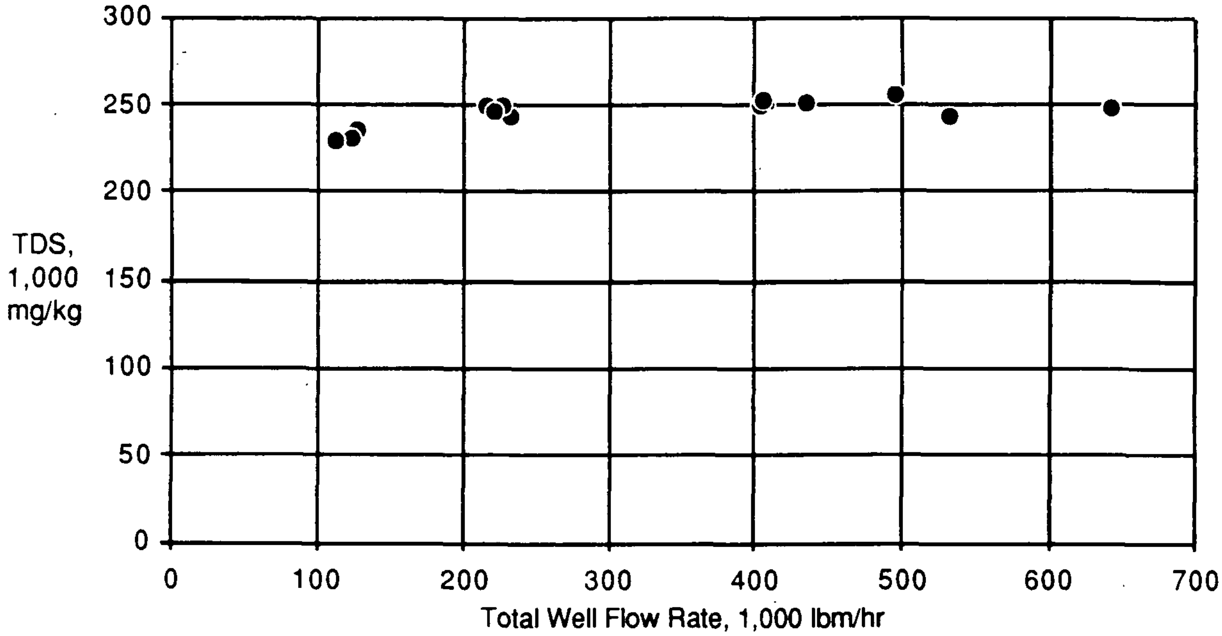


Figure 4-9   Variation of Total Dissolved Solids with Flow Rate

Table 4–4

Geothermometers
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step	Second Rate Step	Third Rate Step	Flow Test in Mar 1986	Flow Test in Dec 1985
Sodium (Na), mg/kg	49,829	52,537	53,151	Not available	52,661
Potassium (K), mg/kg	13,526	13,152	15,116	Not available	16,502
Calcium (Ca), mg/kg	23,128	30,143	30,723	Not available	26,515
Na/K	3.68	3.99	3.52	4.09	3.19
Na/Ca	2.15	1.74	1.73	1.86	1.99
Ca/K	1.71	2.29	2.03	2.20	1.61
TDS, mg/kg	235,000	249,000	253,000	251,000	255
Total well flow, lbm/hr	127,000	227,000	402,000	?	100,000 (approximate)

These changes in the geothermometers, Na/K, Na/Ca, and Ca/K, lead to the following conclusions:

- More than one zone is producing a significant portion of the total well flow.
- The various zones are producing different proportions of the total flow as the well flow is increased.

Comparison of the Na/K, Na/Ca, and Ca/K ratios for the second rate step during the June 1988 flow test with the corresponding ratios for the March 1986 test shows very little difference. Therefore, the producing zones and their relative contributions were essentially the same for the two test conditions.

The information from the December 1985 test and the data for the flow test in June 1988 permit comparison of fluids produced from 6,000 to 6,200 ft (1,829 to 1,890 m) depth with fluids that are from several different zones. In December 1985, the fluid produced by the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) appears higher in potassium and roughly equal in sodium, calcium, and TDS concentrations to the fluids produced in June 1988. Curiously, these generalizations apply more closely for the second and third rate steps than for the first; one hypothesis is that the higher well flow rates may favor production from the relatively shallow zone from 6,000 to 6,200 ft (1,829 to 1,890 m).

Comparison with Other Wells in the Area. The chemistry and static (nonflowing) temperatures for the State 2-14 well were compared with those for 11 other wells in the vicinity for which data are available as nonproprietary information.

Chemistry. Table 4-5 lists chemical composition data for the State 2-14 well (for the third rate step) and 11 other wells shown in Figure 4-10. Comparing the order of listing in Table 4-5 with the locations in Figure 4-10 shows that the wells are listed left to right in Table 4-5 in roughly a southwest–to–northeast order. Additional information about the relative depths of the wells is shown in Figure 4-11, which uses the same left-to-right order as in Table 4-5. The comparisons may be summarized as follows:

Table 4–5

Brine Chemistry of Geothermal Wells in the Vicinity of State 2-14
(mg/kg of total well flow)

	Sinclair No. 4	Sinclair No.3	Magmamax No. 1	Woolsey No. 1	Elmore No. 1	State No. 1	IID No. 2	IID No. 1	Sportsman No. 1	River Ranch No. 1	**State 2–14**	Hudson No. 1
Ammonia	––	283	304	254	342	––	––	341	––	––	375	––
Arsenic	8	8	––	––	––	––	––	10	––	––	11	––
Barium	––	––	––	––	––	––	208	196	––	167	94	––
Boron	633	450	117	121	––	158	325	325	124	––	399	––
Calcium	22,492	12,125	17,583	13,250	26,083	17,667	24,000	23,333	28,725	31,667	30,723	26,917
Chloride	128,825	78,042	109,417	95,667	153,333	105,833	129,167	129,167	167,500	173,333	150,000	173,333
Copper	––	––	0.8	1	––	2	3	7	––	––	4	––
Iron	––	––	233	121	3,833	1,000	1,667	1,742	3,500	1,750	1,448	1,667
Lead	34	67	39	24	74	67	67	70	––	81	70	––
Lithium	239	41	42	54	233	150	175	179	125	250	174	267
Magnesium	613	650	92	142	150	23	8	45	15	183	13	––
Manganese	850	342	529	363	825	792	1,142	1,250	––	1,583	1,132	1,833
Potassium	12,425	6,517	8,667	7,500	18,917	11,667	13,750	14,583	20,000	18,583	15,116	16,500
Silicon	75	––	200	125	––	––	333	333	4	––	117	––
Silver	––	––	0.3	––	––	1	––	1	––	––	0.19	––
Sodium	48,700	30,283	42,750	36,083	53,500	39,833	44,167	42,000	58,333	57,167	53,151	52,250
Strontium	358	300	––	296	608	––	367	500	––	700	371	650
Zinc	––	––	183	92	––	417	417	658	––	––	459	––
TDS	215,000	129,000	180,000	154,000	258,000	178,000	216,000	215,000	278,000	285,000	253,000	273,000
pH	5.3	5.3	5.6	6.0	––	––	––	5.2	––	––	5.3	––

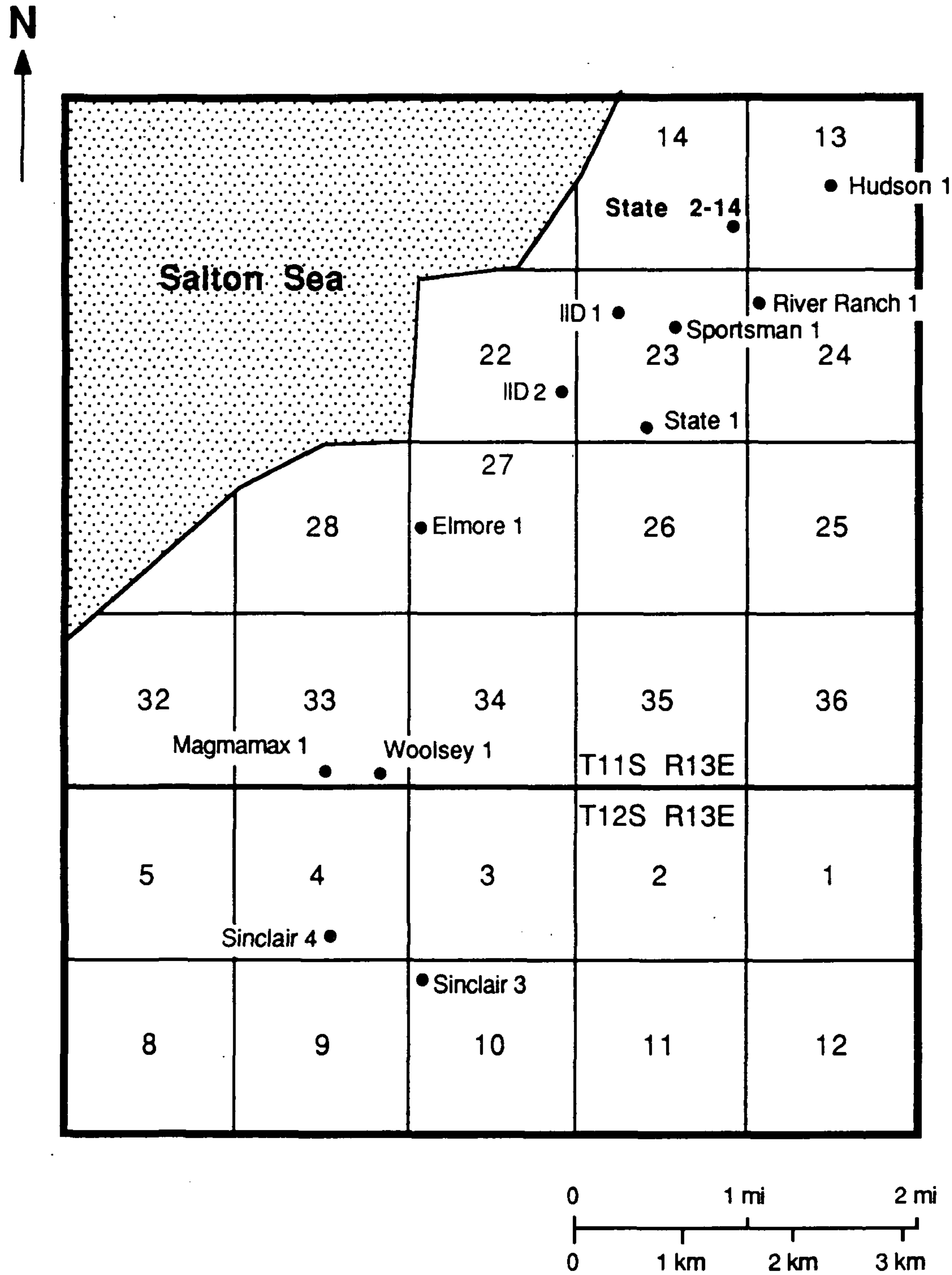
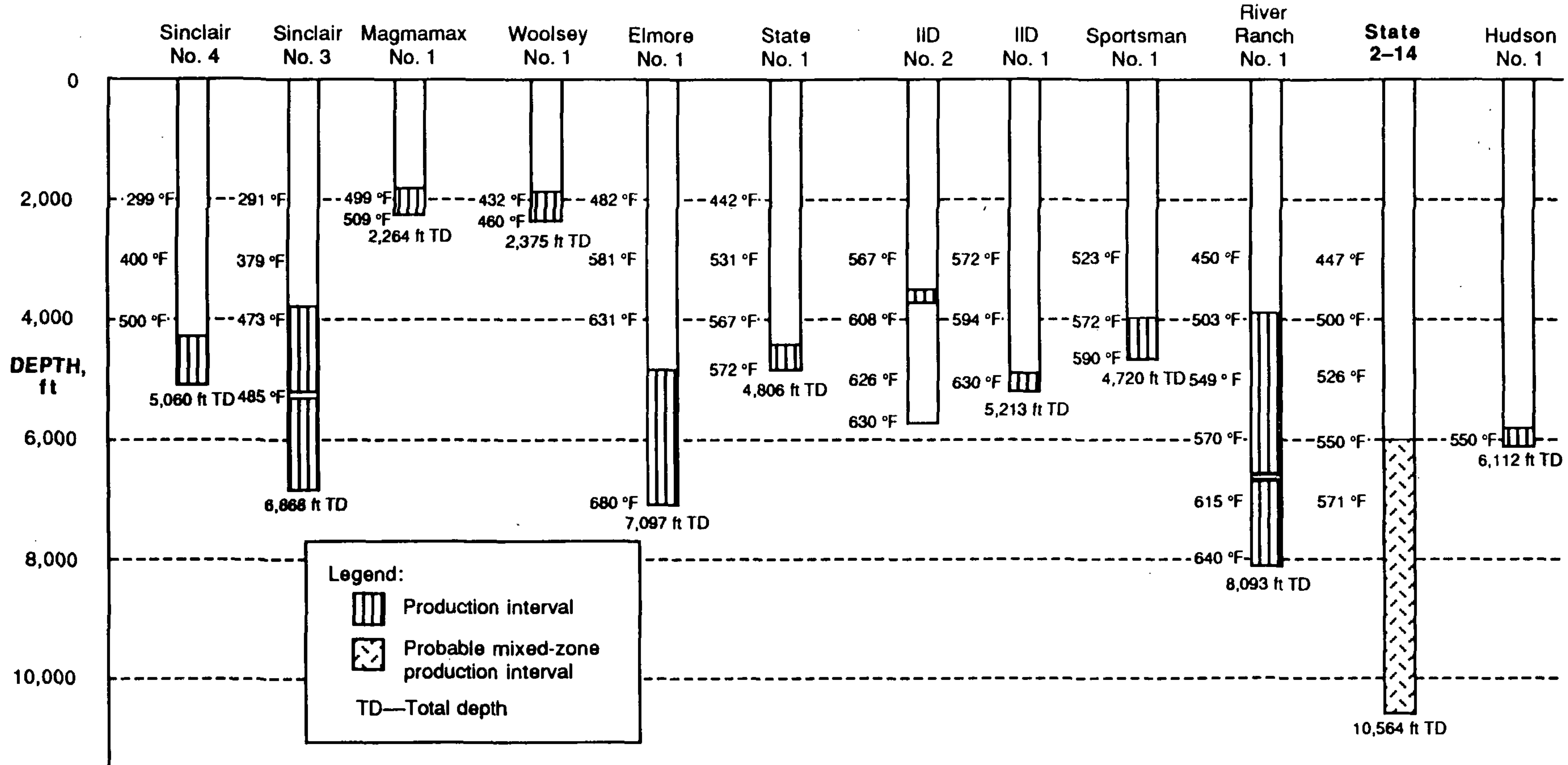


Figure 4-10 Locations of Wells Compared with State 2-14



	Sinclair No. 4	Sinclair No. 3	Magmamax No. 1	Woolsey No. 1	Elmore No. 1	State No. 1	IID No. 2	IID No. 1	Sportsman No. 1	River Ranch No. 1	State 2–14	Hudson No. 1
Na/K	3.92	4.65	4.93	4.81	2.83	3.41	3.21	2.88	2.92	3.08	3.52	3.17
Na/Ca	2.17	2.50	2.43	2.72	2.05	2.25	1.84	1.80	2.03	1.81	1.73	1.94
Ca/K	1.81	1.86	2.03	1.77	1.38	1.51	1.75	1.60	1.44	1.70	2.03	1.63
TDS, mg/kg	215,000	129,000	180,000	154,000	258,000	178,000	216,000	215,000	278,000	285,000	253,000	273,000

Figure 4-11 Characteristics of Geothermal Wells in the Vicinity of State 2-14

- TDS. In general, the wells in the northeast part of this area have higher TDS concentrations. Although depth has often been reported as an important factor with respect to TDS, the River Ranch No. 1 and Sportsman No. 1 wells produce fluid with relatively high TDS concentration from relatively shallow production zones starting at about 4,000 ft (1,219 m) depth.

- Sodium, Potassium, and Calcium. The wells in the northeast part of this area tend to have a lower Na/K ratio, except for the State 2-14 well; this may be due at least in part to the greater depth of its production zones. Likewise, the wells in the northeast part of this area tend to have lower values of Na/Ca ratio. Generalizations concerning Ca/K are not apparent.

The sodium, potassium, and calcium concentrations for the fluids produced during the December 1985 test of the State 2-14 well and those for the Hudson No. 1 well, about one-half mile away, are strikingly similar as shown below:

	Hudson No. 1	State 2-14
Sodium, mg/kg	52,250	52,661
Potassium, mg/kg	16,500	16,502
Calcium, mg/kg	26,917	26,515
Na/K	3.17	3.19
Na/Ca	1.94	1.99
Ca/K	1.63	1.61

In December 1985, an interval between 6,000 and 6,200 ft (1,829 to 1,890 m) of the State 2-14 well was tested, and the production zone in the Hudson No. 1 well was at about 6,000 ft (1,829 m). Thus, the same stratum may be involved in the production from both.

However, the TDS concentrations reported in the two cases are considerably different: 273,000 mg/kg for Hudson No. 1 and 255,000 mg/kg for State 2-14. An anion–cation check of the two data sets revealed that the report for Hudson No. 1 shows apparent excess chloride of about 30,000 mg/kg, and the data set for State 2-14 implies an apparent 10,000 mg/kg excess chloride. Therefore, the TDS concentrations in the two cases could be essentially the same. Subtracting the calculated excess chloride quantities from the reported TDS concentrations yields virtually equal values for TDS concentrations: 243,000 mg/kg for Hudson No. 1 and 245,000 mg/kg for State 2-14.

Therefore, the geothermal fluid produced from the zone between 6,000 to 6,200 ft (1,890 m) depth in the State 2-14 well and the fluid produced by the Hudson No. 1 well probably arise from the same source.

Temperatures. Figure 4-11 shows static temperatures at depths from 3,000 to 7,000 ft (914 to 2,134 m).

Temperatures in the State 2-14 well track those in the nearby River Ranch No. 1 well from 3,000 to 5,000 ft (914 to 1,524 m). At 6,000 and 7,000 ft (1,829 and 2,134 m), the temperatures are 23 and 20 °F (13 and 11 °C) higher, respectively, in the River Ranch No. 1 well.

The temperatures in the State 2-14 well are 120 to 130 °F (67 to 72 °C) lower than those in the Elmore No. 1 well for all depths from 3,000 to 7,000 ft (914 to 2,134 m). Likewise, the temperatures in the State 2-14 well are 80 to 120 °F (44 to 67 °C) lower than those in the IID Nos. 1 and 2 wells from 3,000 ft (914 m), to the total depths for the IID wells, 5,213 ft (1,589 m) for IID No. 1, and almost 6,000 ft (1,829 m) for IID No. 2.

4.2 SCIENTIFIC RESEARCH PROJECTS

One of the objectives of the flow test of the State 2-14 well was to provide opportunity for scientific research projects to be conducted at the same time. Section 4.2 summarizes those projects based on materials submitted by the experimenters, and the submitted materials are included *in toto* in Appendices H through N.

4.2.1 Particle Meter Testing (Battelle Pacific Northwest Laboratories)

The objectives of the field test were as follows:

- Establish the suspended solids content of the brine from the bottom of the separator immediately after flashing and after a two-hour hold time
- Characterize the chemical and size characteristics of the suspended solids
- Evaluate an on-line computerized ultrasonic particle counter in a high-solids brine
- Evaluate the effects of scale deposits on the optical window of a laser particle counter

Figure 4-12 shows a schematic diagram of the experimental equipment. Brine from the bottom of the separator was run through 1/2-in. line about 125 ft (38 m) to the test stand. Brine flow of 5 to 10 gpm (0.32 to 0.63 l/sec) was maintained in this line to limit the residence time before measurements in the test stand to about 30 seconds.

Brine entered the test stand and was split into two streams.

- One stream was available for immediate flow through the laser optical window, an ultrasonic detector, and a weighed filter for measurement of the suspended solids content. Samples of both brine and solids were collected for later analyses.

- The second stream was directed into a heated 6-gallon vessel to hold the brine at temperature for 90 to 160 minutes to allow precipitation. Then the brine was either filtered for weighed samples, or it was directed through a second ultrasonic cell.

The test was started on June 8 and continued until June 15.

The preliminary results may be summarized as follows:

- Solids content of the brine at the test stand inlet varied over a wide range (166 to 670 mg/l). The high inlet solids content indicates that just 30 seconds after flashing in the separator, a substantial solids content had already formed in the brine. The data have a fairly wide scatter, probably due to both varying solids content and to difficulties in washing residual soluble salts out of the salt cake on the filter media.

- Silica is a major constituent of the solids. Barium sulfate was identified, and compounds of lead, arsenic, strontium, zinc, calcium, antimony, and silver were detected.

- The ultrasonic particle counter operated successfully under severe scaling conditions and is usable in its current form. There is a temperature limit of 180 °F (82 °C) on the current ultrasonic transducer.

- The window of the laser particle counter quickly coated with solids and was totally obscured in two days of operation. The laser counter approach would require almost continuous maintenance and would not be suitable for geothermal plant use until a solution is found to keep the windows transparent.

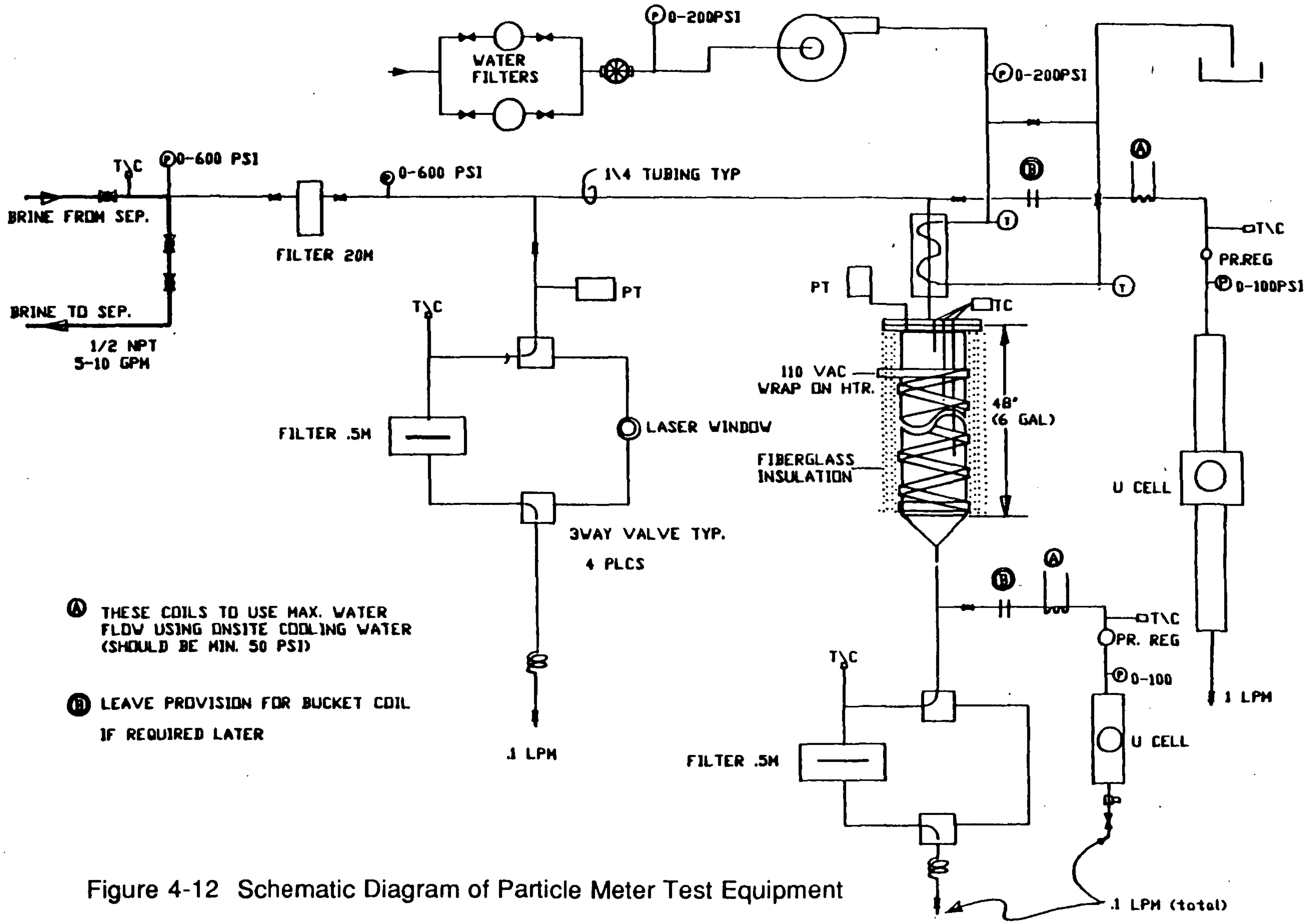


Figure 4-12 Schematic Diagram of Particle Meter Test Equipment

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4.2.2 Chemical Sampling and Analysis to Characterize the Brine (Electric Power Research Institute)

The EPRI CHEMLAB mobile geothermal laboratory was on-site throughout the flow test to collect and analyze samples from the State 2-14 well. The types of sampling events are defined as follows:

- Signature. To characterize chemical and physical attributes of the total flow from the well. This involves combining measurements of steam and brine to determine properties of the total flow
- Tracking. To observe changes in selected parameters as a function of time
- Special. To investigate flow streams or equipment of special interest

Complete signature tests were conducted at the three rate steps with flows from 125,000 to 402,000 lbm/hr (57,000 to 240,000 kg/hr).

Daily tracking tests were conducted at the brine sampling port from June 7 to June 20 (except for June 19). This port sampled the separated brine emerging from the separator as in the signature tests.

Special tests included the collection of raw samples for determination of the total suspended solids. These results were made available to help estimate the sludge accumulation rate in the brine pond.

By August 15, the analysis of signature samples was nearly complete, and tracking samples were still being analyzed for chloride and nitrate (by ion chromatography) and for all 30 metals (by ICAP).

Results of the analyses by the EPRI mobile geothermal laboratory were used extensively in preparation of Section 4.1.3, Brine Chemistry Results.

4.2.3 Seismic Monitoring (Lawrence Livermore National Laboratory)

The purpose of the seismic monitoring project was to characterize in detail the microseismic activity related to the flow/injection test in the Salton Sea Geothermal Field. The goal was to determine if any sources of seismic energy related to the test were observable at the surface.

Figure 4-13 shows the configuration of the seismic stations during the flow test. The network consisted of seven 3-component stations within a 3 km (1.86 mi) radius of the two wells and three small (100 m or 328 ft aperture) arrays at distances of 1 to 2 km (0.62 to 1.24 mi). The three-component stations, which provide primarily phase arrival times, were used to detect and locate microearthquakes. The arrays, which can provide direction, velocity, and depth information for incoming seismic energy, were used to monitor sources of seismic energy origination from the flow/injection zone.

Preliminary results do not indicate any microearthquake activity within the zone of interest. Data processing is continuing to search for both microearthquakes and continuous energy sources.

4.2.4 Metal Ion Concentrations (New Mexico State University)

Brine samples were collected from the two-phase flowline near the wellhead of the State 2-14 well, and an additional sample of brine was taken from the weirbox at the outlet of the atmospheric flash tank.

Samples of the liquid phase from the flowline were taken with a teflon-lined probe/cooling coil assembly. Temperatures at the sampling point were essentially the same as at the wellhead, or near 492 °F (256 °C).

The weirbox sample was obtained by dipping a container into the active flow stream. That fluid was then suction filtered directly into a sample vial.

All samples were sent to a commercial laboratory for neutron activation analyses of precious metals. Results of those analyses are given in Table 4-6.

4.2.5 Transport of Platinum Group Elements, Gold, and Sulfur in the Salton Sea Geothermal Brines (University of California at Riverside)

Fluid and solid samples were collected between June 10 and 15, 1988, during the flow test of the State 2-14 well. After the flow test, scales were collected from the throttle valve and from an orifice plate valve in the brine line downstream of the separator.

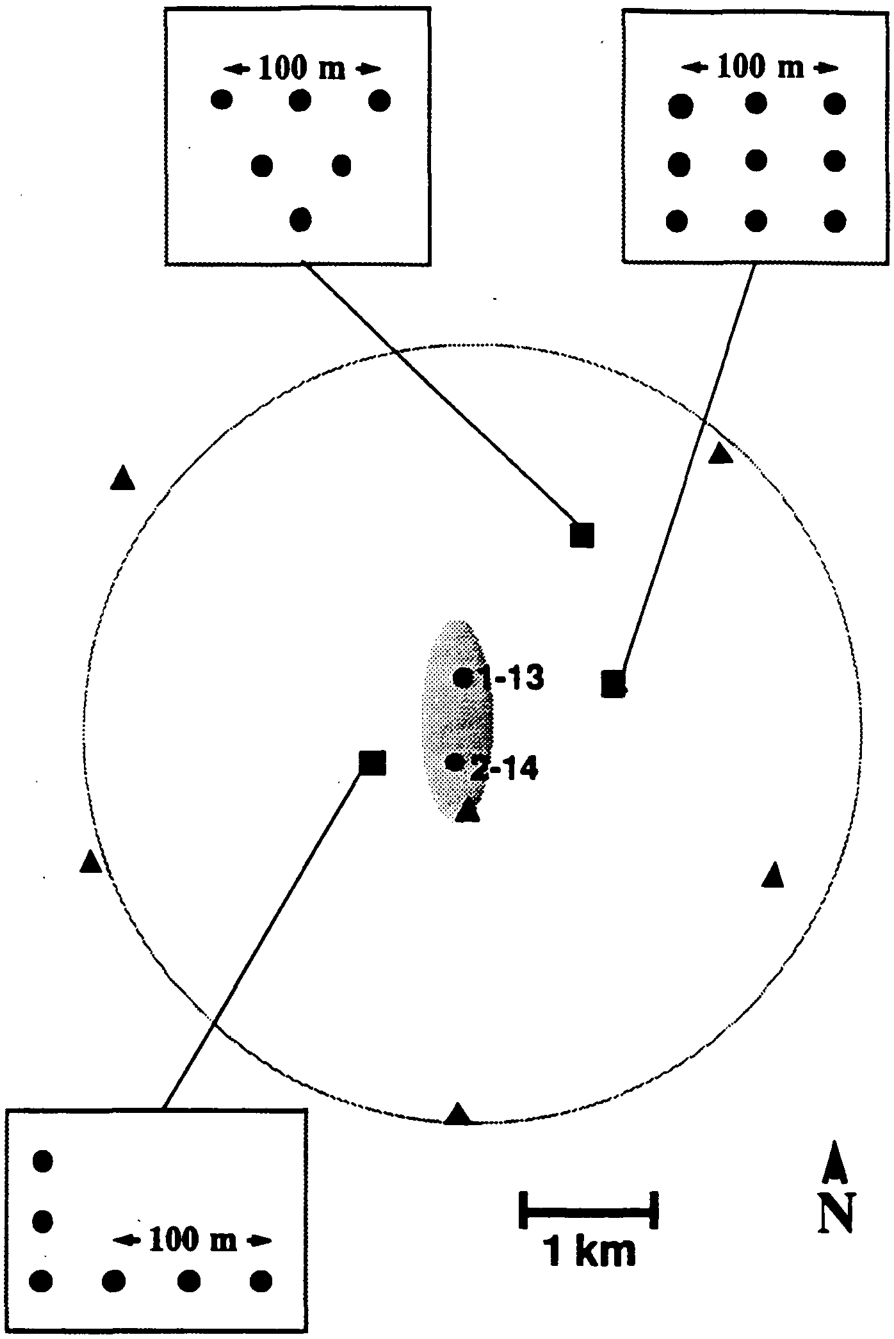

Figure 4-13 Configuration of Seismic Stations

Table 4-6
Neutron Activation Analysis of Precious Metals
in Salton Sea Geothermal Water: Well State 2-14

	Metal Concentration (PPB)*					
Sample	Ag	Au	Pt	Ir	Pd	Comments
DMA 05	ND < 540.	0.0717±0.0122	ND < 16	-	-	Sample from flowline collected 6/3/88 after 500 ml passed through sampler.
DMA 08	ND < 290.	-	-	-	-	Sample from flowline collected in dilute nitric acid immediately after collection of DMA 05.
DMA 02	-	0.0586±0.0047	5.25±1.47	-	-	Sample from flowline (unacidified) collected immediately after DMA 08.
DMA 03	-	0.0683±0.0057	4.80±1.10	-	-	Sample from flowline (unacidified) collected 6/4/88 after 1000 ml passed through sampler.
DMA 06	ND < 500.	-	-	-	-	Sample from flowline (acidified) collected immediately after DMA 03
DMA 01	890.±134	0.0258±0.0054	ND < 12.	-	-	Sample collected 6/5/88 at Weirbox after geothermal waterexposed to atmosphere. Sample was filtered through 0.45μ filter prior to collection.
DMA 07	ND < 140.	-	-	ND < 0.8	-	Sample from flowline collected 6/5/88 and acidified.
DMA 04	-	0.0325±0.0036	ND < 4.	-	ND > 6.5	Sample from flowline (unacidified) collected immediately after DMA 07.
179	ND < 140	0.120±0.008	ND < 8.4	-	-	Sample from flowline (acidified) collected immediately after DMA 04

* ND - Not Detected below limit of detection

The samples are being analyzed for platinum, palladium, rhodium, gold, hydrogen sulfide, sulfate, iodine, thallium, scandium, arsenic, antimony, rubidium, gallium, and indium.

Preliminary results (dated August 9, 1988) on the platinum group elements and gold indicate that significant levels of these elements are not being transported by the Salton Sea geothermal brines. These results conflict with the results of other researchers; differences are attributed to use by others of analytical techniques that are prone to serious matrix interferences. Results from sulfur isotope analyses are not yet available.

4.2.6 Uranium Series Isotope Measurements (University of Southern California)

Brine and gas samples were collected from the State 2-14 well on June 10 and 15, 1988, during the flow test. This fluid sampling and subsequent uranium series isotope measurements are expected to provide information that will further constrain models of radioisotope exchange mechanisms and develop new methods of estimating hydrogeologic parameters.

By August 16, 1988, the results were incomplete.

4.2.7 Liquid and Gas Sampling (University of Utah Research Institute)

The purpose of the liquid and gas sampling and analysis are to determine if differences in the chemistry of the fluid occur as a result of changing flow rates and to determine whether silica precipitates when a cooling coil is used during sample collection.

Three samples were taken during a 1-hour period on June 8 when the flow rate was about 125,000 lbm/hr (57,000 kg/hr), which was near the lowest flow rate of the test. Four samples were collected during a 2-hour period on June 17 when the flow rate was approximately 640,000 lbm/hr (290,000 kg/hr), which was the highest flow rate that was sustained for a few hours during the test. The samples were taken from the brine and steam lines downstream of the separator.

Two different methods were used for sampling the brine:

- The first method involved cooling the hot brine in a 1/4-in. stainless steel tube coil prior to capturing the fluid in a preservative solution. Although this method is commonly employed, it may promote precipitation of silica in the cooling coil prior to capturing the fluid.

- The second method used a 6-in. length of 1/8-in. tube that was inserted directly into the preservative solution with no prior cooling. This method is expected to prevent silica precipitation prior to capturing the fluid.

Both methods use a preservative solution of 5 percent by weight nitric acid for ICP analysis, 5 percent by weight hydrochloric acid for sulfate and ammonia analysis, and a nondiluted sample for chloride, fluoride, and total dissolved solids analysis. The acid-to-sample dilutions in the samples were 10:1.

Steam samples were taken through a 1/4-in. stainless steel cooling coil. The samples were taken in evacuated Pyrex flasks that contained solutions of sodium hydroxide and cadmium chloride.

By August 8, 1988, the liquid and gas samples were being analyzed.

Section 5

SITE CLEANUP

This section describes the site cleanup objectives and the means used to meet them, and discusses in detail the brine pond cleanup options.

5.1 SITE CLEANUP OBJECTIVES

The objective of the site cleanup activities is to clean the site and equipment sufficiently to turn them over to Kennecott, subject to the following specific conditions:

- The equipment and trailers furnished by DOE are to be left in place for DOE to transfer ownership to Kennecott.
- The mud pit and brine pond are to be cleaned to a point where they are suitable for reuse.

The equipment and trailers required little cleanup because they were to be assumed "as is." Housekeeping procedures during the flow test had kept these in reasonably good shape.

The mud pit was cleaned in late May during preparations for the flow test. At that time, the mud pit was dry with several inches of dried drilling mud residue in the bottom. This nonhazardous material was scraped up, loaded, and hauled to the IT Corporation disposal site near Westmoreland, California. Since the mud pit was not used during the flow test, it required no further cleaning.

Cleaning the brine pond presents a greater problem. The options for that are discussed in detail in Section 5.2 below.

5.2 BRINE POND CLEANUP

The objectives of the brine pond cleanup are to remove and dispose of the wastes in the brine pond and to clean the brine pond to the compacted liner. Decontamination of the pond by removal of the liner material is not required.

Brine fluids from short-duration flow tests in December 1985 and April 1986, one 12-hour flow test in August 1987, and the flow test in June 1988 were discharged into a brine holding pond located across Davis Road from the wellhead. Excess brine fluids were injected into the Imperial 1-13 well. In addition, some drilling muds were pumped into the brine holding pond during the Phase 1 drilling operations. Both waste streams contain heavy metals that must be analyzed to determine whether the wastes are hazardous or nonhazardous.

The sludge in the brine pond consists of precipitates from the brine and drilling muds. This sludge was sampled on several occasions and tested to determine the waste classification. Based on the characteristics of the waste, waste management treatment requirements were identified, and quotations from qualified bidders were solicited. The bidders proposed various approaches to the problem of waste management.

5.2.1 Waste Characterization

Brine pond sludge was sampled and tested for chemical constituents and physical properties on the following occasions:

Sample 1 – June 1987, prior to well repair operations; analyzed by ATS Laboratory

Samples 2C, 24C, and 24G – March 1988, after the 12-hour flow-test and prior to the long-term flow test; analyzed by ATS Laboratory

Sample 3 – June 23, 1988, after the flow test in June 1988; analyzed by Quality Assurance Laboratory

Sample 4 – July 6, 1988, after the flow test in June 1988; analyzed by ATS Laboratory

Sample 5 – July 6, 1988, after the flow test in June 1988; analyzed by BTC Environmental Inc.

Table 5-1 shows the samples taken, methods of sampling, and sample analyses requested.

Table 5–1

Samples Analyzed

Sample	Date	Sampling Method	Analyses
Sample 1	6/87	Scoop from top of sludge	California Assessment Manual (CAM) metals
Sample 2C	3/88	Dipping from boat	CAM metals, TDS, moisture, ash, acid insoluble ash, cations, anions
Sample 24C	3/88	Same as for 2C	Same as for 2C
Sample 24G	3/88	Same as for 2C	Same as for 2C
Sample 3	6/88	Scoop from top of sludge at 6 sites; blended sample	CAM metals; STLCs run by two different laboratories
Sample 4	7/88	Scoop from top of sludge; one site	CAM metals; pH, total Cl, soluble Cl, moisture, CAM metals on washed sample
Sample 5	7/88	Scoop from top of sludge; one site	CAM metals, hydrocarbons

Appendix O contains the laboratory reports showing results of chemical analyses and shows the California Department of Health list, Inorganic Persistent and Bioaccumulative Toxic Substances, and their threshold concentration values for heavy metals. If the metal concentrations exceed these thresholds, the waste is deemed hazardous and would require disposal at a Class 1 site unless treated. If the waste is nonhazardous, it could be disposed of at a Class II site.

Appendix O also contains a copy of Kennecott's permit from the Regional Water Quality Control Board; page 4 of this permit shows the allowable limits for Class III waste disposal. If the nonhazardous waste is below an allowable threshold of 6,000 mg/l total dissolved solids (TDS), it could be disposed of at a Class III site such as the Brawley dump.

The sample analyses show that the waste present in the pond prior to the flow test in June 1988 was nonhazardous; all constituents are below the allowable limits for Total Threshold Limit Concentration and Soluble Threshold Limit Concentration (TTLC and STLC) values.

Analyses of Samples 3, 4, and 5, taken after the flow test in June 1988, are contradictory. The concentrations of heavy metals are below the thresholds for TTLCs for all samples. However, the soluble cadmium concentration reported for Sample 3 exceeds the STLC allowable value; and the soluble lead concentration for Samples 3 and 4 exceeds the STLC allowable limit. Therefore, the sludge waste in the brine pond is potentially hazardous, although the analyses vary considerably among the three laboratories. Sample 3, run by Quality Assurance Laboratory, shows extreme variation for STLCs for two runs on the same sample. For example, the concentration of arsenic reported for the June 30 analysis (2.0 mg/l) is 2.1 times the value for the July 5 analysis (0.965 mg/l) run on the same sample. The concentration of cadmium reported for the July 5 analysis (3.16 mg/l) is 1.8 times the value for the June 30 analysis (1.77 mg/l). These variations suggest that either the analyses are suspect or the analyses are subject to extreme statistical variations. The concentrations of lead STLC analyses for Samples 1-5 were: 0.85, 3.35, 2.85, 2.54, 42.75, and 40.2; 13.0 and 12.7; and 2.44 mg/l respectively.

Further sampling and analyses are unlikely to provide better information than the contradictory results already obtained. The variations within a sample, between laboratories, and, most importantly, between samples taken at different sites at different times suggest the impossibility of improving confidence in the results. The waste is a mixture of brine precipitates and drilling muds that may have high lead and cadmium concentrations, particularly in the top layers. Depending on the sludge mixture, the waste could be either nonhazardous or hazardous.

5.2.2 Waste Treatment Options

If the waste is disposed of as hazardous, waste management methods must either 1) reduce the volume of waste by dewatering and washing the filter cake to remove soluble chlorides (with this method, the waste must be disposed of at a Class I site) or 2) fix the metals to render the waste nonhazardous for disposal at a Class II site.

The chloride content and total dissolved solids are between 10 and 12 percent by weight of the wet sludge. TDS in the dewatered sludge would be 15 to 20 percent. This suggests that the weight of the dewatered sludge could be reduced by at least 10 percent if the filter cake were washed with freshwater. However, freshwater washing would not be expected to reduce the TDS from a level greater than 200,000 mg/l to less than 6,000 mg/l. Therefore, to meet requirements for disposal at a Class III dump will require fixation of the soluble constituents.

Carbonate content was analyzed in the March 1988 samples and found to be 1 to 2 percent by weight of the wet sludge. Carbonate salts could be dissolved by addition of acid to further reduce the volume of filtercake to be disposed. However, addition of acid would dissolve the metallic salts and could further exacerbate the problem of soluble heavy metal concentrations.

The physical properties of the sludge affect the estimated cost for treatment and disposal. Table 5-2 shows physical property assumptions. These have been determined from laboratory analyses and from information provided by waste management contractors who have sampled and analyzed the sludge.

Table 5–2

Assumed Physical Properties

Sludge Volume:	10,000 bbl 420,000 gal
Sludge Density:	1.3 s.g. (wet sludge) 1.5 s.g. (dry solids)
Percent Solids in Wet Sludge:	30 percent
Sludge Weight:	10.3 lb/gal (wet) 4,326,000 lb (wet) 2,163 tons (wet) 1,297,800 lb (dry) 649 tons (dry)
Allowable Water Content : (to pass paint filter test)	40 – 45 percent
Sludge Weight with 45 percent Water: (after dewatering)	1,180 tons
Sludge Soluble Salt Content:	10 – 15 percent (wet)
Sludge Weight After Fresh Water Rinse: (assumes removal of 10 percent salts)	1,062 tons

5.2.3 Waste Cleanup

At the time this report draft was prepared in late August 1988, the brine pond cleanup contractor and process had not been selected.