Title
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Publication Date
1980-05-01

356
10-16-80

DC 1844

LBL-11153
UC-66d

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A. Hlinak, J. Lobach, K. Nichols,
R. Olander, and D. Werner

May 1980

Prepared for the U.S. Department of Energy
under Contract W-7405-ENG-48

LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA
BERKELEY

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Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price Code: A05

LBL-11153

FINAL DESIGN, INSTALLATION AND BASELINE TESTING OF 500 KW DIRECT CONTACT PILOT PLANT AT EAST MESA

May 30, 1980

Prepared for:

Contract No. 4158102
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This work was supported by the U. S. Department of Energy under Contract W-7405-ENG-48.

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1.0 INTRODUCTION

This final report covers the design, fabrication, field installation and baseline testing of the "500 kW Direct Contact Pilot Plant" at the East Mesa Geothermal Component Test Facility. The effort was performed for the Lawrence Berkeley Labs (LBL) and the Department of Energy (DOE) under LBL Contract No. 4158102.

Studies by the Ben Holt Company, Ford, Bacon and Davis, and DSS Engineers in 1976 and 1977 (Refs. 1, 2, 3) indicated that a geothermal powerplant operating with a direct contact heater exchanger could be viable economically and even equivalent with the economics of a plant utilizing a standard tube-and-shell configuration. The advantages of the direct contact approach with the high mineral content waters convinced DOE to explore the performance potential with a small pilot plant of approximately 500 kW net power potential. A definition study was performed by Barber-Nichols in late 1977 and early 1978 to select and optimize the process and equipment for this pilot plant (Ref. 5).

The pilot plant was configured to accomplish two objectives - first to evaluate the overall performance potential of direct contact powerplants and second to develop design criteria and parameters for full-scale direct contact plants. The pilot plant includes all of the process functions that would be incorporated in a full-scale plant. Incoming brine is treated to remove undissolved gases, pumped through the direct contact heat exchanger (DCHX), and then sent to a recovery system for removal of the dissolved working fluid. The chosen working fluid is isobutane (IC_4). The working fluid loop includes a radial inflow turbine with generator, condensers, hotwell reservoir, and a feed pump. A downwell pump was installed in the geothermal well to supply the plant with unflashed brine.

This phase of the DOE evaluation of the DCHX concept includes design, fabrication and preliminary testing of the plant defined in the referenced definition study. Future testing will be performed to develop comprehensive performance data, design criteria and economic factors for the DCHX-type powerplant.

2.0 SUMMARY

The pilot plant design is based on a modular concept that allows factory fabrication and enables it to be moved to different geothermal resource sites. There are nine modules that make up the pilot plant. The condensers, working fluid storage system, utility cooler, hotwell and DCHX are single-function groupings whereas the brine module, power trailer, control trailer and environmental (fan) module are multiple-function groupings. The brine module performs incoming brine processing, energy recovery, and working fluid recovery functions as well as brine pressure boosting. It also houses the hydraulic recovery turbine. The power trailer contains the turbine-generator and most of the electrical power handling equipment. The control

trailer houses the control logic and data systems. The environmental module provides clean, conditioned air to the power and control trailers and compressed air for the control valves.

The modules were fabricated and delivered during the period of March to September, 1979, to the East Mesa site with installation and preliminary checkout being completed in December, 1979. There were no major problems encountered with assembly, installation and checkout.

The Geothermal Component Test Facility provides electrical power, makeup water, fire system pump and water as well as geothermal brine and its subsequent disposal. A geothermal downwell pump was installed in well Mesa 8-1 to provide unflashed, pressurized geothermal brine to the pilot plant.

The baseline tests for the 500 kw pilot plant were completed in January, 1980. These tests verified the basic plant design. Component operation and performance were measured and each module performed as expected with the exception of the power turbine.

Testing began with the downhole REDA pump and continued through the brine delivery system including the sand trap and brine pump. The DCHX and hydrocarbon loops were started with vapor flow bypassing the power turbine. During this period the instrumentation and control loops were set up and checked out and operator training was initiated. Safety systems such as the hydrocarbon gas detectors, fire system and vent systems were also checked out in this phase of testing. Minor operational problems were encountered with the brine flow control and heat recovery loops. These problems did not allow the plant to be operated in a fully-automatic mode, but with manual control from the control trailer no significant plant instabilities were encountered.

Preliminary performance data were obtained for the hydrocarbon and brine pumps, the DCHX, and the condensers. The head and flow rates established by the pumps met or exceeded design specifications. The brine temperature delivered to the plant was lower than the design value. The plant was designed to produce a net output of 500 kW with 340°F brine delivered to it. The actual temperature from well Mesa 8-1, however, was about 326°F. At this lower temperature the DCHX met or exceeded performance specifications. Operating at design brine flow rates (225 gpm), pinch temperature differences between the water and working fluid were in the range of 1 to 2°F. These results indicate that high performance direct contact spray columns in this size range can be accomplished. The evaporative condensers provided design heat transfer rates at less than design temperature differences between ambient wet bulb and condensing working fluid.

The last component of the plant to be operated was the power turbine. With the plant operating in a stable condition, the turbine was started. A mechanical failure of the turbine rotor occurred very early in the run. At first, this problem was thought to be associated with water carry-over from the DCHX to the turbine. Subsequent tests of a second rotor have shown the problem to be a rotor blade failure for reasons other than water or liquid carry-over. The rotor blades appear to be overstressed.

The next phase of testing will be directed toward correcting the rotor problem and obtaining turbine performance data and overall plant power generation performance. Working fluid loss fractions will be evaluated by taking fluid samples of the exiting brine. The effect of non-condensible gases on condenser performance will also be evaluated. The 500 kW pilot plant design should be a useful test vehicle for evaluating the critical parameters for a DCHX power-generating system.

3.0 PROCESS AND PERFORMANCE SUMMARY

The 500 kW DCHX pilot plant was designed to produce a net output of 500 kw with a brine inlet temperature of 340°F at an ambient wet bulb temperature of 64°F. Total plant parasitic losses were calculated to be 306.9 kW, resulting in a gross plant output of 806.9 kW. Design brine flow rate is 222 gpm, resulting in a predicted net plant output of 5.1 watt-hr/lb of flow. The design parameters developed for the plant and its components are delineated in the following sections.

3.1 PROCESS ANALYSIS AND DIAGRAM

A study of thermodynamic cycles for this DCHX pilot plant was conducted during the design definition phase (see Ref. 1). Isobutane, isopentane and N-pentane were examined over a range of peak cycle temperatures and condensing pressures. The results of the cycle studies produced a utilization factor expressed as net watt-hr/lb of brine flow. Isobutane provided the highest utilization factor compared to the other cycles at brine temperatures of 340°F. At lower brine source temperatures (290°F) the performances of isobutane (IC_4) and pentane cycles are nearly the same, with IC_4 having a slight advantage.

Plant capital costs for the pentane system appear to be essentially equal to costs for an IC_4 cycle at the same net output power. The pentane cycles operate at lower DCHX pressures, eliminating the need for the brine boost pump and hydraulic turbine. This results in lower gross power levels for the plant and lighter gauge materials in the pressure vessels. These advantages are offset, however, by the larger diameter power turbine and DCHX to handle the greater volume flows for the pentane system. Evaluation of plant costs for the IC_4 and pentane systems showed that they were nearly the same and IC_4 was selected for the pilot plant due to its improved utilization factor.

The process flow diagram and selected cycle state points are shown in Figure 1. The incoming brine passes through a combination sand-and-carbon dioxide (CO_2) separating vessel. The boost pump then increases the pressure of the brine to 453 psia for injection into a spray column DCHX.

The brine is cooled to 149°F in the DCHX and, after passing through an IC_4 recovery system, is returned to a facility pond for re-injection. The IC_4 working fluid is pumped from the hotwell to a pressure of 485 psia for injection at the bottom of the DCHX. As the IC_4 droplets flow to the top of the DCHX through the descending brine, they are heated to 250°F, boiled, superheated to 255°F and taken off the top of the heat exchanger as a vapor. This vapor, along with some water vapor, passes through a single-stage radial inflow turbine to the condenser where the mixture is condensed at 94°F and returned to the hotwell. The hotwell separates the condensed water and IC_4 liquid phases. The water fraction is directed to the recovery system and the IC_4 returns to the feed pump, completing the cycle.

The brine temperature drop in the DCHX is 190°F, resulting in a calculated minimum or pinch temperature difference between the brine and IC_4 of 7°F. The system power balance and calculated parasitic loads are shown in the following table.

TABLE I

SYSTEM POWER BALANCE AND CALCULATED PARASITIC LOADS

Component	Efficiency	Load, kw
Condenser motors		77.7
Organic feed pump and motor	$\eta_p = .75$ $\eta_m = .90$	96.7
Brine boost pump and motor	$\eta_p = .76$ $\eta_m = .90$ $\eta_d = .95$	54.4
Brine discharge pump and motor	$\eta_p = .70$ $\eta_m = .85$	2.1
Recovery system		15.0
	Total electrical	245.9
Gearbox and alternator	$\eta_{gb} = .97$ $\eta_{al} = .85$	61.0
	Total parasitic	306.9
Power turbine	$\eta = .83$	776.7
Hydraulic turbine	$\eta = .81$	30.2
	Total output	806.9
	Net output	500.0 kw

Three major factors influencing plant performance and economics are 1) the control of non-condensibles that contaminate the power cycle condenser, 2) the equipment required to limit working fluid losses, and 3) the control of scaling or performance-robbing deposits in critical components. These factors are related and control of one often impacts control of the other two. The 500 kW pilot plant has been designed to investigate and demonstrate viable solutions to all three factors.

3.2 MAJOR COMPONENT DESIGN AND SELECTION

Analysis and definition of the plant cycle required realistic values for the performance of many of the major elements used in the plant. To obtain these values, the component had to be evaluated and the results used in extensive iterations of cycle and plant performance analysis. With the definition of these conditions finalized, performance and design requirements for the major elements were also finalized. These components with their parameters are discussed in the following sections.

3.2.1 Direct Contact Heat Exchanger

The direct contact heat exchanger (DCHX) transfers heat from the brine to the IC_4 working fluid. The DCHX configuration is a spray tower with the hot brine injected at the top of the vessel and allowed to flow to the bottom, forming a continuous column of liquid approximately 30 feet high. Cold IC_4 is injected near the bottom of the vessel through a perforated plate, forming small droplets of dispersed liquid. The IC_4 is less dense and only sparingly soluble in the surrounding brine, and these droplets rise through the column absorbing heat through direct contact. Preheating, boiling and superheating of the IC_4 all take place in the same vessel.

Figure 2 is a graph of brine and IC_4 fluid temperatures as a function of heat transfer for the selected design point conditions. Isobutane enters the bottom of the DCHX through a distributor plate, emerging as small droplets that rise through the brine. Heat transfers from the brine to the droplet, heating it ultimately to the IC_4 saturation temperature (250°F). After boiling and superheating 5°F, the IC_4 vapor will be in equilibrium with a small amount of water vapor (estimated to be 1.4% by weight of the total mixture) and exits at the top of the column. The brine enters the top of the DCHX at 335°F and, at the minimum, approaches the IC_4 temperature in the preheater within 7°F and exits at 149°F.

If the downward velocity of the brine exceeds the rising droplet velocity, the IC_4 is swept out the bottom of the DCHX with the exiting brine. This carry-under condition is avoided by selection of the vessel diameter. Based on available correlations (Ref. 6) of holdup (defined as the column volume fraction occupied by IC_4) and carry-under, an inside column diameter of 40 inches was selected. This diameter is expected to yield an actual holdup equal to 90% of the holdup that occurs just prior to carry-under conditions.

The lengths of the heating zones were determined from the selected diameter and the estimated average volumetric heat transfer coefficients for preheating, boiling and superheating. For a preheating coefficient of 3800 Btu/°F-ft^3-hr, a boiling coefficient of 9375 Btu/°F-ft^3-hr, and a superheating coefficient of 1620 Btu/^oF-ft^3-hr, respective lengths of 27 feet, 2.5 feet, and 0.5 foot are expected at design conditions.

In addition to heat transfer, the large surface area created by the rising IC_4 droplets promotes the mass transfer of small amounts of IC_4 to the brine and evolution of dissolved CO_2 from the brine to the IC_4. Based on data collected by DSS Engineers (Ref. 4), the expected level of dissolved IC_4 leaving the DCHX with the brine is 200 ppm (19 lb/hr). The expected CO_2 leaving the top of the DCHX with the IC_4 is 500 ppm (44 lb/hr).

The IC_4 distribution head was designed to provide an injection velocity of 1.96 ft/sec to achieve proper droplet size and dispersion in the column. This requirement resulted in a shower head design 34 inches in diameter with approximately 12,900 holes of 0.078 inch diameter installed at the bottom of the DCHX column. Brine input to the column is not critical and the inlet only requires a baffle to provide distribution of the brine across a plane normal to the axis of the column.

3.2.2 Condensers

The vapor mixture (IC_4, steam and CO_2) leaving the turbine is condensed to liquid in the condensers by transferring heat from the mixture to a heat sink. Heat sinks considered for the project were air, flowing water and evaporating water. There was no available source of flowing water (such as a river or canal) and the use of dry air cooling was considered unacceptable because of large fan parasitic power requirements and high condensing temperatures which would reduce cycle efficiency and plant output power for a fixed brine flow and temperature. Therefore, evaporating water was selected as the condenser heat sink.

Two types of condensers that use evaporating water were then evaluated: 1) conventional cooling towers with shell-and-tube condensers, and 2) evaporative condensers. An evaporative condenser is similar to a cooling tower with the cooling tower fill replaced by the condensing coil. Working fluid vapor is condensed inside the condensing coil, the outside of which is continually wetted by a recirculating water system. Air is simultaneously blown upward over the coil, causing a small portion of the recirculated water to evaporate. This evaporation removes heat from the coil, thereby cooling and condensing the working fluid vapor inside the coil.

The study comparing an evaporative condenser and the more conventional approach showed fan power for either system to be similar, but because the water flow rate and flow losses in the evaporative condenser are less, thereby reducing pump power, the evaporative condenser has lower parasitic horsepower. Hence, an evaporative condenser was selected for the 500 kW system.

The driving potential in an evaporative condenser is the temperature difference between condensing temperature and entering air wet bulb temperature. Operation with high dry bulb temperatures concurrent with low wet bulb temperatures results in some of the cooling capability of the condenser being used to cool the warm entering air. However, this effect is slight and performance of evaporative condensers is usually predicted as a function of entering wet bulb temperature only.

The condenser module design point interface conditions at East Mesa are:

Entering air wet bulb temperature - 64°F
Nominal working fluid inlet pressure - 70 psia
Condensate temperature - 94°F
Working fluid composition: IC_4 - 27.2 lb/sec
Water - 0.39 lb/sec
CO_2 - 0.012 lb/sec
Entering water quality - 88.3%
Temperature of entering working fluid - 142°F
Heat load - 17 x 10^6 Btu/hr
Electrical requirements: 77.5 kW max., 440 v, three-phase
Makeup water (incl. blowdown) - 80 gpm at 30 psi
Blowdown - up to 40 gpm at two cycles of concentration which is conservative. Actual cycles of concentration will be determined by test.

The condenser was sized for a three-component working fluid consisting of 27.2 lb/sec of IC_4 vapor and 0.39 lb/sec of water. The entering water quality if 88.3% vapor by mass. Along with the IC_4 and water, equilibrium calculations predict a CO_2 flow rate of .012 lb/sec. This small CO_2 flow rate should have a negligible effect (less than 1%) on the condensing coefficient. The design condenser heat load is 17 million Btu/hr assuming no liquid subcooling. The predicted electrical input to the fans and pumps at design is 77.5 kw.

The condenser also has the capability of providing 3000 to 3500 gpm of closed-circuit cooling water for a subsequent test of a shell-and-tube condenser.

The predicted off-design performance is shown in Figure 3 which summarizes the effect of wet bulb temperature and condensing heat load on condenser pressure. As expected, the condenser pressure increases with increasing heat load and entering wet bulb temperature.

3.2.3 System Pumps

The cycle studies for the plant design used pump efficiencies of 70% for the brine boost and 75% for the IC_4 feed pump. These efficiencies were selected as representative of pumps available at the required operating conditions. High efficiencies are required to maximize plant performance and this parameter was the most significant factor in selecting the pumps. Both pumps are required to handle liquids close to saturation conditions, resulting in very low input net positive suction head (NPSH).

The brine boost pump selected for the plant will flow 222 gpm of brine at the required head of 950 feet. The pump is a 14-stage vertical turbine unit capable of operating at 0 NPSH at the suction flange with an efficiency of 75%. The pump is equipped with a dual input right-angle drive. A vertical motor is coupled to the vertical shaft and the horizontal shaft is coupled to the hydraulic turbine. The vertical drive motor for the pump is a 75 hp, three-phase unit that should be close to 89% efficient.

To strip the IC4 from the brine leaving the DCHX, it is necessary to reduce brine pressure from 450 psia to approximately 5 psia. This pressure energy is recovered in a hydraulic turbine. The hydraulic turbine selected is a Pelton wheel at 3000 rpm coupled directly to the horizontal shaft of the right-angle drive. At design conditions, the turbine will produce 30.2 kW of the required pump input of 54.4 kW at an efficiency of 81%. The recovered power is based on a 97,200 lb/hr flow rate and a turbine exhaust pressure of 20 psia.

The IC_4 feed pump selected is capable of operating with 0 NPSH at the inlet flange. At a flow rate of 387 gpm and a head of 420 psi, the pump is 76% efficient and is guaranteed to lose no more than 2% in efficiency after 4000 hours of operation. This pump requires a vertical shaft motor of 150 hp with a thrust bearing to take the pump thrust load. The motor was supplied with the pump and should be capable of operating at efficiencies in the 90% range.

3.2.4 Power Turbine

Based on the design conditions presented in Section 3.1, a preliminary analysis of the power turbine was performed. At a rotational speed of 25,000 rpm, a turbine specific speed of 29.5 (gas volume in ft^3/sec) was calculated. At this level of specific speed, maximum efficiencies of greater than 80% can be achieved with either axial or radial flow turbine hardware.

The selected turbine configuration is a radial inflow design operating at 25,000 rpm. The impeller is 7.75 inches in diameter and the predicted efficiency is 0.83 at the design conditions specified in Section 3.1. The turbine is provided with variable nozzles that give an adjustable throat area. At a constant inlet pressure flow, rates from 60 to 120% of design can be accommodated with small changes in turbine efficiency.

3.2.5 Recovery System

The IC_4 recovery system is designed to remove 95% of the dissolved IC_4 from the brine stream exiting the DCHX and return it to the hotwell. A two-stage flash operation is employed to separate the IC_4 (and a portion of the dissolved CO_2) from the brine stream. The flashed vapors are compressed and then cooled to recondense the IC_4 (separating it from the non-condensing CO_2) prior to re-injection to the hotwell. Carbon dioxide left behind in the recovery condenser is vented. The design is based on a total brine stream entering the recovery system of 97,200 lb/hr containing 50 ppm CO_2 and 200 ppm IC_4 at a temperature of 145°F.

The recovery is accomplished in two separate stages, part in the tailstock tank and the remainder in the recovery tank. The tailstock is operated above atmospheric pressure to eliminate the risk of air infiltration through the rotating seals of the hydro-turbine. Two-stage flashing allows the recovery to occur at a lower total vapor flow rate (and therefore a smaller recovery compressor) than a single flash. Because of the high volatility of IC_4 relative to water, approximately half of the total recovered IC_4 can be flashed in the tailstock tank at a total pressure of about 17 psia. This high pressure relative to the vapor pressure of the 145°F water results in low levels of flashed steam off the tailstock tank and significantly reduces the total flow to the recovery compressor. For tailstock conditions of 17 psia and 145°F and a Henry's law constant for IC_4 in water of 2.72×10^4 atm, the stream flow from the first flash stage to the compressor and condenser are as follows:

CO_2	0.6 lb/hr
Water	0.7 lb/hr
IC_4	9.3 lb/hr

After leaving the tailstock, the brine stream is flashed a second time in the recovery vessel, liberating the remainder of the recoverable IC_4. Because the operating pressure at this point (5 to 6 psia) approaches the saturation pressure of water at 145°F, significant amounts of steam are evolved with the IC_4, increasing the required capacity of the recovery compressor. For recovery tank conditions of 5 psia and 145°F and a Henry's law constant for IC_4 in water of 2.72×10^4 atm, the stream flow from the second flash stage to the compressor and condenser is as follows:

CO_2	2.3 lb/hr
Water	7.0 lb/hr
IC_4	8.8 lb/hr

Losses of IC_4 from the pilot plant occur at two points. First, dissolved IC_4 remaining in the flashed brine is carried off to the re-injection pond. This loss decreases as the recovery tank pressure decreases. The second loss occurs as residual IC_4 vapor escapes with the CO_2 vented from the recovery condenser and decreases as recovery condenser pressure increases. The minimum total loss (see Figure 4) at a compression ratio of 18:1 occurs at condenser pressures in the 100 to 120 psia range. This corresponds to recovery tank pressures in the 5.5 to 6.7 psia range, yielding total IC_4 losses of about 40 ppm relating to brine inlet flow rate.

3.2.6 CO_2 Removal From Incoming Brine

The geothermal brine to be used in the pilot plant from the East Mesa wells has a high level of dissolved CO_2 and, on occasion, entrained CO_2. The presence of dissolved CO_2 in the brine, when used in a DCHX, results in CO_2 carry-over in the working fluid to the turbine and, thence, into the condenser. The CO_2 will not condense and builds up in the condenser to an equilibrium level. The equilibrium level increases the condensing pressure which, in turn, reduces turbine power output and cycle efficiency. At the predicted levels of CO_2 in the incoming brine, approximately 400 ppm, a 10% loss in cycle performance is predicted. Evaluation of CO_2 effects resulted in the selection of 50 ppm as an acceptable level which amounts to less than a 1% penalty in performance.

A flash tank was incorporated to control the CO_2 level in the brine supply to the DCHX to the 50 ppm level. The decision was made to use a single stage of flash rather than a multiple-stage approach. The penalty for the single stage is that for a fixed flash temperature drop it will remove 86% of the CO_2 as compared to a three-stage which will remove 96%. The three-stage unit would be the approach used on a commercial powerplant. For this pilot plant, the single-stage unit is less costly and allows various levels of CO_2 concentration to be tested to verify the analytical models. Analysis predicts that five degrees of flash will result in a CO_2 level of 50 ppm (the five degrees is the temperature drop of the brine after the limited flashing). The heat available in the flashed-off steam and CO_2 is recovered in a downstream heat exchanger.

3.2.7 Flashed Steam Heat Recovery

The partial flashing of the brine stream for CO_2 removal results in a CO_2 and steam mixture that contains 2.3% of the incoming energy. By condensing the steam and boiling additional IC_4, a large percentage of this energy can be recovered. An evaluation of heat exchange requirements based on the cycle conditions showed that a cost effective exchanger could recover 65.3% of the lost energy. The heat exchanger was designed for a shell-side input of 533 lb/hr of steam and 100 lb/hr of CO_2 at 335°F. An IC_4 flow rate of 2650 lb/hr is vaporized to saturation conditions at 260°F from 96°F. The heat exchanger is inclined from the horizontal at 22.5°F to provide a collection zone for condensed water to allow additional heat recovery by subcooling. Condensing pressure for the steam with the CO_2 present is 95 psia. The condenser is vented at the cold end to dispose of the CO_2 and condensed water.

4.0 PILOT PLANT DESIGN DESCRIPTION

The design configuration of the plant was keyed to several requirements that were developed early in the program. Construction of the plant in modules would allow a majority of the fabrication to take place at the factory instead of the field, thus saving cost and time. Modules were sized and the interfaces configured so that the plant could be disassembled and shipped to other sites.

To minimize the interface with electrical utilities at the test site and still provide a configuration where net power could be monitored, the plant was configured with a parasitic load bank that would accept the gross power level and a synchronization system that would allow switchover of the support equipment from the utility to the plant generator. This approach provides utility power for startup and non-generating mode testing. It also allows a self-contained operating mode while avoiding the interface problems of pumping large amounts of power back into the utility grid.

A major concern in the design of the plant was personnel safety. To assure a safe plant and one that satisfied all the applicable state and national codes or standards, a safety evaluation was made to develop design and operating criteria for the plant. The major concern for safety was the flammability potential of the IC_4 liquid and vapors. The design safety criteria include isolation of all electrical energy sources, a venting system for the relief valves and the use of insulation or water spray for protection of the structures in case of fire (Ref. 7).

4.1 SITE AND PLANT LAYOUT DESCRIPTION

Initial installation of the pilot plant is at the government's East Mesa Geothermal Component Test Facility near Holtville, California. A new pad was constructed on the southern edge of the existing facility located to provide convenient access to some of the services required from the facility. The eight inch brine line from well 8-1 was rerouted and reconfigured to make room for the pad and provide the brine source for the powerplant. The layout of the plant and the pad are shown in Fig. 22. The module placement was selected to minimize the length of plumbing lines while providing access to equipment that would require maintenance or on which different experiments might be tried.

The interface with the East Mesa test facility includes three lines for handling the geothermal brine. A four inch line brings the hot geothermal brine from the eight inch line (to well 8-1) into the brine handling module and a four inch line returns unused brine back to the East Mesa flash tank. The used brine is returned in a four inch line to be deposited in the settling pond. Fresh well water is supplied from the test facility for use in the condensers and utility coolers through a three inch line. Blowdown water from these units is returned via a four inch line. The facility fire pump is used to supply the monitors and spray system through a four inch line with an operating switch located on the pad. A 600 amp, 460 volt, three-phase power drop is the last service supplied by the facility.

4.2 MODULE DESCRIPTION

The various modules that were designed for the plant are described in the following sections. The interconnections between the modules include some of the instrumentation and control valves used in the system. Figures 23 - 30 give a good overview of the modules and their installation at the site.

The design of the modules and the plant subsystems used all of the applicable codes and standards to achieve total system safety. Applicable codes included the ANSI, ASME, NFPA and the California Administrative Code.

4.2.1 Brine Module

The brine module is skid-mounted and contains equipment for handling and preconditioning the brine before it enters the DCHX, equipment for recovering IC_4 from the brine leaving the DCHX, and equipment for recovering energy from the steam evolved during incoming brine treatment.

4.2.1.1 Brine System

The brine system includes a supply and return subsystems. The brine supply subsystem controls brine flow rate, removes sand and dissolved gases (primarily CO_2) and raises the brine pressure for injection into the DCHX. The brine return subsystem removes IC_4 dissolved in the brine leaving the DCHX and recovers some of the pressure energy added in the brine supply subsystem.

Brine is supplied to the brine module from the well by a downhole pump and pipeline. Brine from the pipeline is sprayed into the sand trap vessel where sand and calcium carbonate ($CaCO_3$) particulates are permitted to settle and liberated CO_2 gas is vented off. The primary purpose of the vessel is to eliminate a large amount of the dissolved CO_2. This is accomplished by spraying the brine into a vapor space at the top of the vessel at a pressure that allows some of the water to flash into steam. Brine flows by gravity from the sand trap to the brine boost pump where the pressure is raised from 115 to 485 psia to overcome pressure drops and static liquid head before the brine enters the DCHX.

Brine is returned to the East Mesa test facility either as hot, unused brine or as cool, spent brine. The hot return brine has bypassed the DCHX. Brine is bypassed around the DCHX during plant checkout, startup, shutdown, or when the plant is operating at lower brine flows than the downhole or brine boost pumps will tolerate. This hot brine is returned to the East Mesa test facility at approximately 150 to 200 psig.

The spent brine leaves the DCHX at approximately 140°F and 450 psia and contains pressure energy and dissolved IC_4. The pressure energy in the spent brine is removed by a hydraulic turbine. The brine pressure is reduced to approximately 30 psia across the hydro-turbine nozzle causing some of the dissolved IC_4 (along with some brine and CO_2) to flash into vapor. The vapor is removed by the IC_4 recovery system. The spent brine flows by gravity from the turbine to the tailstock which is mounted directly to the bottom of the turbine case. The brine then flows through spray nozzles into the recovery vessel. Pressure in the recovery vessel is reduced to approximately 5 psia to liberate additional dissolved IC_4. The brine flows by gravity from the recovery tank to the brine discharge pump where the pressure is increased to 5 psig for return to the East Mesa settling pond.

4.2.1.2 IC_4 Recovery Subsystem

As the brine and IC_4 flow through the DCHX, some IC_4 goes into solution in the brine and is carried out with it. This IC_4 loss represents an economic penalty to a commercial powerplant and the system described below recovers most of the IC_4, thereby improving plant economics.

The spent brine is flashed twice after leaving the DCHX - once in the hydraulic turbine and once in the recovery vessel. At each reduction in pressure some of the dissolved IC_4 comes out of solution as a gas along with some water vapor and CO_2. The pressure in the hydraulic turbine and tailstock is maintained at 15 psig. This pressure was selected to eliminate air leakage past the shaft seals into the IC_4 recovery system. Within the operating pressure range selected for the turbine, the predicted amount of IC_4 remaining in the brine was still felt to be excessive for a commercial powerplant and an additional flash stage was added utilizing spray nozzles and a second vessel called the recovery vessel. The brine is sprayed into the recovery vessel where the pressure of the brine is reduced to 5 psia across the spray nozzles allowing additional IC_4 to be liberated. The condensed water removed from the hotwell is mixed with the brine in the tailstock so that the dissolved IC_4 in it can also be recovered.

The IC_4, CO_2 and steam mixture is piped from the tailstock and recovery vessel to the recovery compressor through a liquid trap. The pressure of the stream from the tailstock is reduced across a control valve to the pressure of the stream from the recovery tank. The liquid trap collects water that may have condensed in the connecting piping or that was carried into the compressor suction piping. An accumulator connected to the liquid trap collects the liquid. When the accumulator fills, it is manually isolated from the recovery system, pressurized with CO_2 and the liquid drained. The accumulator is then returned to service. After leaving the liquid trap, the vapor enters the first stage of the two-stage recovery compressor. The gas leaves the first compressor stage and passes through a water-cooled intercooler heat exchanger. After the gas leaves the intercooler it enters a liquid separator which removes any condensed water and then it enters the second stage of the compressor. The compressed gas leaves the compressor, passes through a check valve and enters the recovery condenser which is a water-cooled tube-and-shell condenser where heat is rejected to cooling water from the utility cooler. The volume of condensate is measured before being returned to the hotwell. Vapors not condensed in the recovery condenser are vented to the plant vent manifold.

4.2.1.3 Flash Steam Heat Recovery System

The raw brine is partially flashed in the sand trap to remove most of the dissolved CO_2. This flashing produces a steam-CO_2 mixture which is vented from the sand trap and sent to a heat exchanger for recovery of the thermal energy. This tube-and-shell heat exchanger is used to boil additional IC_4 which is added to the working fluid stream from the DCHX.

4.2.1.4 Component Descriptions

The following major components of the brine module are discussed in detail: sand trap, brine boost pump, hydraulic turbine and tailstock, recovery tank, recovery compressor, binary heat exchanger, and recovery condenser.

The name "sand trap" is, perhaps, unfortunate because the sand trap's functions are to partially flash the brine and thereby remove dissolved CO_2 and to provide a collecting point for $CaCO_3$ produced as a result of the brine flash. The brine outlet fitting is positioned 5.5 inches above the vessel bottom to allow for accumulation of material.

The brine is flashed by spraying it into the vessel through two spray nozzles. The spray droplets provide a very large surface area for mass transfer of CO_2 and other dissolved gases from the brine. Two nozzles were provided with shutoff valves to allow proper spraying velocities to be maintained at low flow rates. To reduce scaling downstream of the sand trap, concentric expanded metal trays have been placed in the vessel which provide a large surface area for $CaCO_3$ scale formation, thereby minimizing scale buildup in the downstream piping. The vessel has a volume of approximately 640 gallons and is designed for a pressure of 300 psi at $400^{o}F$.

The brine boost pump raises the pressure of the brine leaving the flash tank to the operating pressure of the DCHX plus system pressure drops. At the design point the pump raises 222 gpm of brine from 115 to 485 psia assuming a brine density of 56.15 lb/ft^3, which is a head rise of 953 feet. Additional stages can be added to increase the head rise to 1188 feet at 222 gpm if required. The available NPSH for the pump is very small at the sand trap. To provide sufficient NPSH, the pump is mounted in a pit and the sand trap elevated, providing approximately 13 feet of suction head. The boost pump is Byron Jackson's model 600 VLTX1H1e-4x6x16.5SH, a 14-stage canned vertical turbine pump that has porcelainized iron bowls and iron impellers for improved performance. Seal cooling requirements are approximately 5 gpm of 100°F water and are provided by the system utility cooler.

A right-angle geardrive is mounted on top of the brine boost pump to drive the pump and utilize the hydraulic turbine. This drive combines input power from the vertical electric motor mounted to the top of the drive and the input power from the hydraulic turbine through the right-angle drive. No provision for a one-way clutch has been included since the turbine will not be operating unless the brine boost pump is also operating. The turbine selected for brine pressure energy recovery is a nine inch pitch diameter impulse turbine known as a "Pelton Wheel". Brine is injected against the wheel through a single pintle-controlled nozzle. The pintle allows the turbine to operate efficiently over the full flow range. The turbine is mounted above a vessel known as a "tailstock" which collects the brine as it exits the wheel. The tailstock is vented to the recovery system through a pressure control valve. This valve keeps the vessel pressure at 30 psia and allows the stripped gas and IC_4 to be picked up by the recovery system. The tailstock and turbine housing are maintained at 30 psia to prevent air from leaking past the seals into the recovery system and to provide sufficient head to deliver the brine to the recovery tank.

The recovery vessel has a volume of approximately 690 gallons and is designed for a maximum pressure of 50 psig at 250°F. The brine enters the tank through three spray nozzles to provide a high surface area for stripping. The vessel working pressure is 5 psia during recovery operations but is pressurized with 2 psig CO_2 to exclude air when shut down.

The recovery compressor that compresses the vapor liberated in the tailstock and recovery tank to the pressure level in the recovery condenser is an oil-free design by Corken International. The unit is a two-stage, non-lubricated piston-type model D390. The compressor is a vertical configuration and employs two sets of piston rod packings, an oil slinger on each piston rod, and a distance piece to prevent crankcase lubrication from entering the cylinders. The resulting dry cylinder compression prevents contamination of the recovery gas stream. The maximum recommended operating temperature is 350°F at the compressor outlet. Because of the relatively high operating compression ratio and polytropic exponent of the recovery stream gas mixture, a water-cooled intercooler was added to prevent overtemperature of the Teflon piston rings. The intercooler (Young Radiator Co. model SSF 202 HYIP) was sized to limit the interstage gas mixture temperature from 250 to 170°F using available utility cooler water at 100°F. Interstage cooling below 170°F may result in condensation of the water fraction in the recovery stream causing destructive liquid slugging of the second stage cylinder. To prevent condensate from entering the second stage, a liquid separator with a liquid drainer is located at the intercooler exit. Automatic shutdown of the compressor will occur if the second stage outlet temperature reaches 350°F or if a high condensate level is sensed in the liquid separator. In addition, the compressor will automatically unload through a hydraulic unloader if the crankcase lubrication system pressure drops below 20 psi. Compressor suction valves are held open during startup to unload the motor. A time delay permits the valves to operate properly after design operating speed is reached.

The recovery condenser is a water-cooled tube-and-shell heat exchanger that transfers condensing heat from the gas mixture to the cooling water. The gas mixture is comprised of varying amounts of IC_4 vapor, water vapor and CO_2. The cooling water is directed through the tubes while the gas mixture enters the shell end opposite the water connections. Non-condensible gas is vented from the top of the shell at the end opposite the gas inlet. Condensate is drained through a fitting near the cooling water connections. The heat exchanger is a TEMA-type BEU with four water passes. The U-tube construction results in a tube configuration that has provision for thermal expansion, but is not cleanable mechanically. However, because the cooling water is in a closed, clean, treated system, this is not felt to be a problem. The shell side is designed for operation up to 500 psig; however, the maximum working pressure is limited to 300 psig to avoid collapse of the floats in the condensate drain control system. The heat exchanger incorporates 304 stainless steel tubes and tubesheet for corrosion resistance.

The binary heat exchanger used to recover the flash steam energy is a TEMA-type BEM shell-and-tube, one-pass heat exchanger made of low carbon steel and set up for counterflow operation. Because of the different thermal expansion between the tubes and shell, the shell incorporates an expansion bellows. The binary heat exchanger is mounted at a 22.5° angle from the horizontal with the steam/CO_2 inlet end up. A condensed liquid drain is connected to the shell (steam/CO_2) side to maintain a liquid level side approximately 18 inches above the lower tube sheet. The hot condensate will be subcooled by the cold entering IC_4.

4.2.2 Direct Contact Heat Exchanger

The direct contact heat exchanger (DCHX) is the unique feature of the plant. It operates by bubbling a buoyant working fluid in liquid form in a counter-current direction into hot brine. As the working fluid droplets rise they absorb heat from the brine and vaporize. By mixing the heat exchange fluids intimately, the fixed heat transfer surfaces which can scale are eliminated, resulting in savings in capital and operating costs for the DCHX as compared with conventional heat exchangers.

The DCHX designed for this plant is 41 feet high and 42 inches in diameter. The vessel flares out to a 60 inch diameter at the base to ensure that the brine velocity in the vicinity of the IC_4 distributor is low enough to avoid carrying IC_4 out with the discharging brine. Heat exchange occurs between the IC_4 distributor plate and the brine injection level with preheating requiring about 27 feet and boiling and superheating occurring in the top three feet of liquid.

Four internal column configurations were considered for use in this plant. Three of them contained internals in the form of trays or mixing rings or baffles; the fourth was an open column. The open column configuration was chosen based on its simplicity and on the results of the 10 kW DCHX loop work done by DSS Engineers, Inc. Brackets were installed in the vessel to permit the addition of internals later if testing showed that back-mixing or other problems were limiting performance.

A perforated carbon steel plate, 36 inches in diameter with .078 inch holes spaced .281 inch on staggered centers, was used for the IC_4 distributor plate. Surface treatment of the plate was chosen on the basis of tests done in a small transparent column at the University of Utah. Three samples of plate material were tested, one treated by sandblasting, one coated with black oxide and one with nitric acid pickling. The tests indicated that pickling with nitric acid reduced the surface wettability by hydrocarbons and improved drop formation.

Brine is injected 12 inches below the controlled liquid level through a 2.5 inch diameter nozzle against a baffle plate that distributes the brine horizontally. The brine must be injected below the liquid level to minimize mist entrainment in the vapor leaving the DCHX.

A chevron-type demister is used at the vapor exit to remove mist and droplets that are entrained in the IC_4 vapor. Ports and brackets have been provided in the vessel so that a water spray can be added to the demister to improve its coalescing ability if necessary.

The pressure rating of the vessel and relief valves was chosen at 600 psig on the basis that this would be the highest pressure level tested; also, if the vessel becomes shut in, it will be able to contain the developed pressure without relieving.

The DCHX is designed for seismic related loads of 1 g vertically and 1.5 g horizontally, which are greater than the forces specified for the East Mesa region (Seismic Zone 4) in the 1976 edition of the Uniform Building Code on earthquake regulations. Windloading based on the UBC is not as severe as the imposed seismic loads and, thus, are well within the capability of the structure.

Ladders and platforms have been added to the outside of the vessel to facilitate maintenance and to allow use of viewports in the heat exchanger.

4.2.3 Condensers

The evaporative condensers purchased for this application are modified Baltimore Air Coil model BAC-500 units. The modification includes purge connections on the coil nozzles, slower fan speed to optimize condensing performance versus horsepower, and explosion-proof motors. This condenser can be converted to cool water in a closed-circuit loop for use with a shell-and-tube condenser scheduled for test with the DCHX power loop at a later date.

Each condenser incorporates three multistage axial flow fans which provide a combined air flow of 79,500 cfm. Predicted fan power is 17.6 BHP; however, each condenser is equipped with a 10 hp and a 20 hp motor to permit increasing the air flow to 95,000 cfm if it is desired to increase heat rejection capability. Typical motor performance data indicates that operating 1800 rpm motors at approximately one-half load does not reduce motor efficiency from full load efficiency a significant amount. Estimated heat rejection at the larger air flow is 5.08×10^6 Btu/hr for each condenser (20.3×10^6 Btu/hr for all four condensers). Each condenser contains its own 450 gpm recirculating water pump. Water is distributed over the tubes by V-notch weirs.

The condenser manifold piping was designed to provide proper IC_4 distribution to the condensers. Additional consideration was given to using the condensers as a closed-loop water cooler for subsequent tests with a shell-and-tube condenser. Proper flow distribution to each condenser was achieved by utilizing a large low velocity inlet manifold and incorporating vertical legs on the outlet pipe of each coil section. The vertical legs (sometimes called barometric legs or balancing traps) equalize the outlet pressure of each coil section. Each condenser contains two separate coil sections for a total of eight separate coil sections.

Because the condenser uses evaporative cooling, it is possible for the condensing temperature to be less than the hotwell temperature. The hotwell will then have a higher pressure than the condenser which could prevent condensed liquid from draining from the condenser to the hotwell. To eliminate this problem the hotwell is vented to the condenser inlet manifold. The height of the barometric legs was then designed to be long enough to offset the pressure drop through the condenser coils. Baltimore Air Coil and Barber-Nichols calculations both indicate that eight foot legs are required. Each condenser leg contains a butterfly-type block valve which can be used to stop flow through any specified coil section. The size of the condensate manifold was determined by the 3200 gpm cooling water flow for the shell-and-tube condenser. The manifold ends are sealed by blind flanges to permit connection of the 12 inch water piping at a later date.

Heat rejected by the condenser evaporates part of the recirculating cooling water which increases the dissolved solids content of the remaining water; therefore, provision has been made to monitor recirculating water quality. A water conductivity meter located in a separate water conditioner operates condenser water sump blowdown valves to keep total dissolved solids at an acceptable level. The water conditioning equipment also includes provisions for controlling pH and biological growth. A separate water pump is used to pump water from the condenser water sumps through the water conditioners. The conditioned water is returned to the evaporating water system and sprayed over the condenser tubes.

An analysis was made of the heat sink capability and vapor storage capacity of the condenser and manifolds to determine pressure versus time if cooling capability was lost. The analysis showed that if the plant is operating at design flows and temperature, and there was a sudden shutdown of the condensers, there would be between 100 and 140 seconds for the operators to shut down the system. This evaluation indicated that condenser malfunctions would not be a serious operational problem.

4.2.4 Power Trailer

The power trailer is a module designed to contain and provide a non-explosive environment for the electrical power generating and distribution equipment. The trailer contains the turbine-gearbox-generator on a skid, the power busses and the distribution breakers for the entire plant's electrical needs. The trailer also houses a synchronization panel and some of the various switching gear for the plant support equipment. The trailer is split into two compartments. The compartment at the aft end of the trailer contains the turbine and gearbox and allows the turbine to be plumbed into the rest of the loop through the open trailer doors. The forward compartment of the trailer contains electrical power gear. An isolation wall between the gearbox and generator allows the forward portion of the trailer to be pressurized and purged with fresh air, providing an explosion-proof environment and eliminating the need for expensive individual switch gear enclosures. The pressurized section of the trailer meets the requirements of Class 1, Section 1, Group D of the National Electrical Code for a pressurized area. Pressurization for the trailer is provided by the fan module. The turbine end of the trailer is left open to the environment to allow for rapid dispersal of any IC_4 leakage.

The turbo-generator used in the 500 kW DCHX system is capable of supplying a maximum of 900 kW of three-phase, 480 volt electrical power. The turbo-generating system is built on a self-contained skid which is installed and bolted to the power trailer. The skid, turbine, gearbox and accessories required to support the turbine-gearbox were designed by Mafi-Trench Corporation. The generator was supplied to them for installation and coupling to the turbine-gearbox. The turbo-gearbox skid contains a complete lubrication system, the necessary system seals, controls, and the monitoring and shutdown alarms. The turbine is a radial inflow configuration with adjustable inlet guide vanes which are used to control mass flow through the turbine.

The 900 kW generator supplied for this system is a Kato model 4P6-2000. It is a two-bearing brushless generator that runs at 1800 rpm to produce 60 cycle power. The generator is rated at 900 kW with an .8 power factor or 1125 KVA output at 480 volts. At this power level the generator is approximately 95% efficient and the output voltage is regulated by a Baesler SR-4A voltage regulator.

All electrical power for the pilot plant system is routed through and handled by the distribution equipment contained in the trailer. There are two main busses. One of them is a 1200 amp buss leading from the generator over to a parasitic load. The second is a 600 amp buss that is tied to the incoming utility power, the generator and to all the supporting equipment involved in operating this pilot plant. The distribution system is configured to allow the support equipment to be powered either from the utility or directly from the generator itself. The other requirement of the system is to provide a parasitic load that is capable of absorbing all of the generated electrical power. A synchronization panel is incorporated to provide the capability to switch the support equipment power between the generator and the utility buss. This panel will allow the plant support equipment to be started on utility power and then switched over to generator power during operation if desired.

Electric power to the four condensers, the hotwell and to the brine module is routed through circuit breakers equipped with shunt trip units. The power required for the future ORNL shell-and-tube condenser module will also be routed through a shunt trip-equipped breaker. These modules require enough power that separate buss supplies are run to each one. The modules are equipped with pressurized boxes instead of individually enclosed, explosion-proof switch gear. A pressurization switch monitors these enclosures and will trip the breakers, with the shunt trip units, interrupting power to the modules if for some reason pressurization is lost. Power for other modules is routed through appropriate circuit breakers and supplied to switch gear located in the trailer or to explosion-proof switch gear located at the other equipment. Power for the utility cooler, the fan module and the control trailer, including plant lighting and utility power, is routed through switch gear in the power trailer. The support equipment electrical power used is monitored by transducers and recorded by the data system to allow an assessment of system power production efficiency. Power equipment that is not included as direct support equipment for the pilot plant but is necessary for its operation and test at the test site is routed through circuit breakers located on the utility supply side of the distribution system. Equipment not charged for power usage are the air conditioners and heaters that control the environment for the operating personnel. The pressurization blowers for the trailers, the trailer lights and convenience outlets used for various miscellaneous jobs are fed from a transformer that converts the 480 volt, three-phase down to 208/120 volts. This transformer is supplied through a dual interlocked contacter. The primary side of the contacter is fed from the utility line; however, the secondary is fed from the generator output. This configuration will allow an automatic switchover of this transformer to generator power in the event of a utility power outage when the plant is in operation. This switchover will assure that lights and blower required for operation of the powerplant are available.

The pilot plant system is required to dissipate the net energy that it generates. This requirement is achieved by providing a bank of six 150 kW resistive water heaters. These heaters are 480 volt, three-phase units made by General Electric (model no. JL 3628). Control of the dissipated power has been integrated with a speed-governing control loop. The governor controls three proportional power units which increase or decrease the amount of power absorbed by the heaters to maintain the turbo-generator unit at 1800 rpm or 60 cycle power output. The power control units are Payne 18E 4-45, three-phase SCR controllers. These controllers have been equipped with a current input option that allows them to be driven directly by the governor control unit. The three units are staggered so that their control range breaks up the 4 to 20 milliamp input swing into three segments. Each unit will cover a 5.5 milliamp control interval with unit #1 starting at 4 mils, the second unit at 9.5 and the third unit at 15, with all units being on at approximately 21 milliamps. These units are completely proportional with outputs of 0 to 100% over the control input span. The units are staggered so that the load switching will never be much greater than one-third of the total generator output. By limiting the switch load to less than one-half of the generator's capability, interactions with the voltage regulator are prevented. Each of the Payne proportional power controllers feeds or controls the power to two of the 150 kW banks.

Where practical, the power switching equipment for various motors and subsystems has been enclosed in the pressurized trailer. Contactors or motor starters are included in the trailer for the utility cooler module, the fan module, transfer pump, both air compressors, the turbine oil pumps, the two air conditioners and the two trailer heaters.

Control power for all of the switching gear, various system solenoid valves and other equipment is supplied in 120 volt, 60 cycle, single-phase power. The condensers, hotwell and brine module equipment which are supplied through the shunt trip-equipped circuit breakers have individual control transformers for the various contactors and starters. Other equipment isolated in their own explosion-proof housings or that meet Class 1, Div. 2 requirements are supplied power from a single 120 volt transformer located in the power trailer.

Equipment functions which are not integral with the operational logic of the pilot plant are controlled manually from a switch panel located in the power trailer. This equipment includes the four condensers, the utility cooler, the three pressurization blowers, and the air conditioners and heaters for conditioning the air to the trailers. The equipment is started and operates independently of any of the process modes of operation. The various control devices in the sustem such as the operational pumps, compressors and various solenoid valves are all controlled by switches located in panels in the control trailer but which are routed through the power trailer to these modules. Status lights associated with control functions are provided in the control trailer and/or in the power trailer where appropriate. Status lights associated with all the major power switching gear are controlled by auxiliary contacts located on the switch gear so that a true indication of applied power is received.

A separate control and indicating panel is located in the trailer for the turbine-gearbox skid system. Selector switches are provided for the main and standby lube oil pumps and indicators provide system status information. Loss of lube oil pressure automatically starts the standby oil pump. The motor starters for the turbine oil pumps are located in the trailer and are supplied 480 volt power from an independent circuit breaker. Control power is provided by the 120 volt control transformer. The turbine-gearbox unit has mechanical controls for lube oil temperature control and a seal pressurization system. An electro-pneumatic actuator is provided with the turbine that provides proportional position control of the inlet guide vanes. This actuator will be controlled with a 4 to 20 milliamp signal from a process controller located in the control trailer. The closed-loop control function for the vanes maintains the DCHX pressure at a selected value during loop operation. With the type of governor control being used in the system, the operation of the guide vanes will, in effect, modulate the power output of the turbine.

The speed control loop for the turbo-generator system consists of a Woodward 2301 speed control, three Payne 18E power controllers and six 150 kW load banks. The speed control will enable the system to provide constant 60 cycle power and will control the disposal of all net power generated by the system. The Woodward speed control is supplied from a 24 volt DC power supply which is backed up by batteries. The batteries will allow proper system control during power disturbance conditions. The governor is an isochronous unit capable of holding speed within .5% over the full load range. In addition to the governor system, a speed sensing switch is incorporated that will automatically engage the generator's voltage regulator when generator speed is high enough for safe operation. The speed switch is a Synchro-Start model ESSB that operates from the 24 volt DC supply. The voltage regulator will be enabled whenever generator speed is greater than 1500 rpm.

The synchronization panel provides the system the capability to utilize utility power to run the support equipment or to switch over to the generator power for the support equipment. The synchronization system is set up so that the system can be started on utility power and switched back to utility power if desired. The synchronization system is configured so that immediately after synchronization of the generator to the utility line the utility breaker is opened or, in transferring from the generator to the utility buss, the generator breaker is opened. This capability in the synchronization system eliminates any of the potential problems of interfacing with the utility. The synchronization system is manually switched. The synchronization panel will provide the operator the voltage for both sources and the proper phasing information required for synchronization. The breakers that tie the support equipment buss to either the utility or the generator sources are motor-driven G.E. units and only require the proper presetting of switches and the closure of a switch to effect transfer from one buss to the other. To prevent inadvertent operator error, a phase synchronization permissive relay is placed between the operator's synchronizing switch and the circuit breaker to be engaged for system synchronization. The switchout of the circuit breaker being dropped is automatically achieved by a contact closure on the activated circuit breaker. Both these circuit breakers are equipped with under-voltage dropout relays for system protection and for use in this automatic switchout following synchronization.

4.2.5 Utility Cooler Description

The utility cooler is a self-contained module that provides a closed-circuit water loop to absorb heat from the electrical load banks, recovery condenser, vapor turbine-gearbox, brine boost pump seal, right-angle drive, air compressor aftercooler and recovery compressor intercooler. Heat is ultimately rejected to the atmosphere through an evaporative cooler. Approximately 90% of the utility cooler heat load is from the electric load bank and would not occur in a commercial plant; hence, the utility cooler power is not included in the 500 kW plant's performance analysis.

The utility cooler module was sized to handle the various heat loads during the highest wet bulb temperature anticipated at East Mesa. The module utilizes an evaporative closed-circuit water cooler as the heat sink. The cooling water is circulated through tubes in the cooler while additional water in a separate flow stream is pumped to the top of the cooler and is sprayed over the tubes while air is blown upward over the tubes. Heat to evaporate the water outside the tubes is removed from the closed cooling loop, thereby cooling the water. The module contains a pump and an expansion tank to handle the cooling water circulated to the load banks and other equipment that requires cooling. The utility cooler was sized to provide 275 gpm cooling water flow for the system and reject 2.0×10^6 Btu/hr with an 80°F wet bulb temperature. The load capacity allows the capability to add additional loads if required.

The utility cooler heat exchanger is a model VXI36-3 industrial fluid cooler manufactured by Baltimore Air Coil. The selected unit was purchased unmodified from the BAC catalog. The purchased unit has an insulated casing, electric water heater and modulating dampers for controlling air flow so the unit can be operated in freezing locations such as Raft River, Idaho. The utility cooler uses three centrifugal fans driven by a single motor to supply 23,000 cfm of air. The unit also contains its own vertical, close-coupled 1 hp pump which circulated 150 gpm of water over the tubes.

A portion of the water that flows over the outside of the tubes is piped to a separate water conditioner that monitors the conductivity of the water, which is a measure of the total dissolved solids, and provides an electrical signal to open a solenoid valve for blowdown. The water conditioner also measures the pH of the water and injects acid to lower the pH as required. Biocide is periodically injected into the evaporator water to inhibit the growth of algae and slime.

4.2.6 Hotwell Module

The hotwell is basically a working fluid holding point providing surge volume and extra IC_4 to smooth out transient flow conditions in the system. An additional function of the tank is to remove water from the condensed IC_4. The module also mounts the IC_4 feed pump to boost the IC_4 pressure for injection into the DCHX. During shutdown all the system IC_4 is returned and stored in the hotwell.

The vapor produced by the DCHX is a mixture of steam and IC_4. After condensing the vapors it is required to separate them so that the true IC_4 flow rate to the DCHX can be measured. The water flow rate entering the hotwell as condensate is estimated from the water vapor pressure in the DCHX to be between .4 to 2.0 gpm. The two liquids are separated by being trapped behind a bulkhead where they are held for a time period that allows the heavier water to settle to the bottom of the tank. The water is drained from the bottom of the tank while the lighter IC_4 floats to the top and spills over the baffle. Coalescing surfaces for small droplets are provided in the baffled section to aid in the separation of the two liquids. The other portion of the vessel is for inventory control and holding IC_4 reserves. The hotwell vessel is 25 feet long by 5 feet in diameter and is divided internally by a 4 foot high weir into a 9 foot long separation section and a 16 foot long reservoir section.

Isobutane pressure boosting is handled by an Afton 21-stage vertical centrifugal pump chosen for its efficiency and its capability to handle the low NPSH of the pumped fluid. The pump's low flow limit is accommodated by a bypass valve that opens as flow through the system is decreased toward the pump limits. Installation of the pump requires a pit with a 12 foot depth below the skid to accommodate the pump stages.

4.2.7 Fan Module

The fan module performs three functions:

a) Provides safe* air for pressurizing the power trailer and control trailer and for generator cooling.

b) Provides cooling or heating of the pressurizing air for maintaining temperatures and humidities in the trailers within comfortable ranges.

c) Provides dry, filtered, compressed air for pressurizing electrical switching boxes and for operating instruments and controls.

The fan module is a skid-mounted assembly that incorporates the hardware required to perform the three functions.

Pressurized air flow requirements were determined from NFPA

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* Safe is defined as being less than 14% of the lower explosive limit.

Volume 4, 1977, 496-18, Chapter 3, Section 3-3, for purging control rooms with positive pressure air systems. This code requires a minimum air speed of 60 fpm through all openings capable of being opened or a minimum internal pressure of 0.1 inch water. A 32 x 80 inch door requires 700 cfm air flow to achieve 60 fpm air speed through the opening. However, air leakage from the pressurized trailers was predicted to determine the air flow requirement. Using the 1977 ASHRAE Fundamentals, P. 217, the air leakage from the control trailer was estimated to be in the range of 880 to 1980 cfm. Leakage from the power trailer was similarly estimated to be from 650 to 2600 cfm. The higher predicted air flow from the power trailer is caused by leakage between the generator shaft and trailer bulkhead. Considering the above, 1200 cfm air flow was selected for each trailer. The Kato generator requires 4000 cfm of cooling air which determined the air flow for its dedicated blower. The generator exhaust can be directed either outside the trailer or back into the power trailer for heating. For ease of control and operating flexibility, it was decided to install a separate blower and damper for each air service (control trailer, power trailer and generator). All services draw fresh air from a common 36 inch I.D., 40 foot tall stack. The elevated fresh intake stack will prevent any combination of IC_4 leakage or wind combination from contaminating the required source of safe air.

Heating and cooling loads were calculated from the air flows required for pressurizing the trailers and the weather conditions for the two locations. Each air conditioning system consists of a condenser-compressor unit mounted on the fan module and a separate evaporator coil located in the duct work connecting the fan module to the air conditioned space in the trailers. The ducts to the air conditioned spaces also contain electric resistance heaters for operation during low ambient temperatures. The air conditioners and heaters are controlled by conventional room temperature thermostats.

Clean, dry, compressed air from two compressors is used to operate the control valves and to pressurize some non-explosion-proof electrical boxes. The main compressor is belt-driven from a 7.5 hp electric motor. It is designed to start automatically when the air receiver tank pressure falls below 90 psig and stop when the receiver pressure reaches 100 psig. A smaller 5 hp compressor serves as a backup to the main compressor; it starts automatically if the receiver pressure falls below 80 psig and stops when the receiver pressure reaches 90 psig. Both compressors incorporate centrifugal unloaders to reduce motor starting current.

The hot compressed air is cooled in a tube-and-shell type aftercooler using cooling water from the utility cooler module as the heat sink. After passing through the aftercooler, the air passes to the 500 gallon air receiver tank. This pressure vessel is protected against overpressure and fire by a relief valve and temperature sensitive fuseable plugs. The receiver acts as a compressed air reservoir and will permit operation of the control valves for 15 minutes to permit an orderly shutdown if there is an electrical failure or other reason for both compressors to stop. Instrument and control air is cooled in a refrigeration-type air drier (located in the power trailer) before it is piped to the valves and controls.

4.3 CONTROL SYSTEM

4.3.1 System Description

The 500 kW pilot plant was designed with two types of controls. One is a relay logic control system to control startup and shutdown sequencing. It consists of pressure, temperature, flow and level switches, control relay, time delay relays, status and warning lights, and hand-operated switches. The other type of controls are analog process controls consisting of pressure, temperature, flow and level transmitters, process controllers and process control valves to maintain preset levels, temperatures, pressures and fluid flow rates throughout the loop. The components selected use either 4 to 20 milliamp signals or 3 to 15 psig pneumatic signals. Actuation power for the valves is supplied by compressed air at 80 to 100 psig which drops at the valves to the pressure levels required. The pneumatic units are inherently safe and the electronic portion of the controls is protected with intrinsic safety zener barriers.

4.3.1.1 Control Logic

The control logic incorporates all of the manual and automatic switches, relays, status lights and warning lights to provide interlocks for normal startup and shutdown, and for automatic or emergency shutdown in the event of a component or system failure. The control logic was designed to ensure that the pilot plant could be started only in a set sequence which would provide for safe operation. Parameters would be monitored during operation for additional protection. Before brine or IC_4 flow can be started in the loop, the condensers and utility cooler must be operating to provide cooling water to the seals, all liquid levels in the hotwell, DCHX and sand trap have to be within design limits, instrument air pressure must be above a prescribed minimum value and all vessel pressures have to be within normal limits. Brine must be flowing to the DCHX before the IC_4 pump can be turned on in order to keep from flooding the DCHX with cold IC_4. All control and remote operated shutoff valves in the DCHX and hotwell must be open before starting the IC_4 pump. Turbine-gearbox oil pressure and temperature, and mechanical seal differential pressure must be within normal limits to start the turbine. DCHX fluid level must be below the high limit for the turbine to start. During operation of the plant pressures and liquid levels in the vessels, cooling water flow and DCHX brine exit temperature are monitored for proper limits and the system is shut down when the limits are exceeded.

4.3.1.2 Process Control

Four separate process control loops were incorporated into the DCHX power loop. They are on the sand trap-binary heat exchanger, on the recovery system, on the DCHX and on the hotwell. The primary controls for the pilot plant are associated with the DCHX. The DCHX controls include a brine flow rate control, an IC_4 flow rate control, temperature control and level control.

These parameters are used to control liquid level in the DCHX and the amount of superheat in the working fluid vapor. A pressure control for column working pressure modulates the flow rate through the turbine or the bypass around the turbine to the condenser. Level, pressure and temperature controls are used on the sand trap to maintain a pressure which allows flashing and removal of CO_2 from the brine and controls heat recovery in the binary heat exchanger. Pressure control was used on the recovery system to control venting of non-condensible gases. Liquid level controls were used on the recovery vessels, the sand trap and the hotwell to maintain working fluid and brine levels in those components.

The turbine-generator requires a speed control to handle the changing power levels and maintain a 60 cycle output. Since there is a requirement to dissipate net power production in a parasitic type load, the speed control and the load control are integrated. Turbine speed control is maintained by monitoring turbine speed and increasing or decreasing load to maintain the turbine speed within design limits.

4.3.2 System Configuration

4.3.2.1 Control Logic

a) Block Diagram and Description

Figure 5 is an operational logic block diagram of the pilot plant control logic. All pressure, temperature, flow, level and hand-operated switches are shown in their normally de-energized state.

There are two distinct levels of shutdown as indicated in Figure 5. Those functions which terminate in relays 8CR, 9CR, 12CR, or 29CR shut down the vapor turbine and allow the rest of the DCHX loop to remain operating. Those functions which terminate in relays 36CR or 47CR shut down the entire loop.

There are three control logic loops which shut down individual components without affecting the operation of the DCHX loop. They are for the recovery compressor-condenser, the hotwell water drain and the brine return pump controls. If the water level in the recovery tank drops too low, the brine return pump will stop until the level rises again. If the water level in the hotwell drops too low, the hotwell water drain valve is closed to prevent IC_4 from flowing to the tailstock through the water drain line. If the liquid level in the recovery compressor liquid trap or the intercooler accumulator rises too high, the recovery compressor will shut down. Recovery tank high level, purge compressor overtemperature and/or recovery condenser overpressure also shut off the compressor.

The control logic consists of general purpose control and time delay relays and associated panels containing hand-operated switches and status warning and shutdown lights. It operates from a 24 volt DC, 25 amp power supply.

b) Location of Switches and Controls

The control console is located in a 46 foot by 10 foot specially-constructed control and instrumentation trailer. All relays, hand-operated switches, process controllers, readouts for loop parameters, and status and warning lights are located on the control console. The upper section of the control console contains a process flow diagram with status lights to indicate normal fluid levels and pressures, valve position (open or closed), and pump and fan operation. The lower console consists of four 19 inch racks containing all control relays, switches, readouts, process controllers, power supplies, alarms, gas leak detectors and warning lights. With one exception, all pressure, temperature, flow and level switches are located on the various modules and are connected to the control logic through intrinsic safety barriers. The one exception is the switches in the power trailer for the power turbine. Since both the power trailer area where these switches are located and the control trailer are safe areas, the wiring was routed through conduit directly to the control console.

c) Intrinsic Barrier Panel

Operating the pilot plant with IC_4 creates a Class I, Division I, Group D hazardous condition. For this reason, all electrical signals entering or leaving the process loop must be rendered explosion-proof. There were two ways of accomplishing this, either by routing all signals to and from locally mounted switches and transmitters through rigid explosion-proof conduit and enclosures, or by using an intrinsically safe system. The intrinsically safe system approach was selected.

In this system, all electrical instrumentation and control signals leaving the power or control trailer (safe area) and entering the process loop (hazardous area) and all signals returning from the hazardous area to the safe area are routed through intrinsic safety barriers to ensure that the energy levels of these signals are incapable of causing an explosion.

d) Status and Warning Light Panels

The control console incorporates two separate light panels, a panel depicting the process loop and containing status lights, and a separate warning and alarm panel containing warning and shutdown lights.

4.3.2.2 Process Controllers

a) Block Diagram and Description

Figures 6 through 10 are diagrams of the process control loops. The process control loops consist of both pneumatic and electronic type control elements. All level transmitters (LT), level controllers (LC) and pressure controllers PC101, PC115, PC108, and PC106 are pneumatic type controllers that use 3 to 15 psia proportional pneumatic signals to operate control valves. All pressure transmitters (PT, ΔPT), temperature transmitters (TT, ΔTT), and flow transmitters (FT) use an electronic process controller to supply a 4 to 20 ma signal to a control valve. The 4 to 20 ma signal is converted to a 3 to 15 psi signal proportional to the current signal in a valve positioner to operate the control valve. The process controllers are basically analog computers that utilize an operational amplifier to perform a mathematical operation in the equations that relate input, output and response (gain, reset and rate) within the controller.

b) Location of Switches and Controls

All pneumatic controllers are set locally at the module on which they were installed. Any switches and controls are mounted in a weather-proof controller case attached to the level or pressure controller.

All electronic process controllers are mounted in the control console in the control and instrumentation trailer. The pressure, temperature and flow transmitters as well as the valve positioners are mounted on the process piping and process control valves. Process controller settings are all made from the control trailer and all process controller outputs are displayed in the control trailer.

4.4 INSTRUMENTATION AND DATA ACQUISITION SYSTEM

4.4.1 System Description

The pilot plant was configured with two types of instrumentation. Mechanical type pressure and temperature gauges were placed at appropriate points in the system for monitoring operation, providing technicians with system status while they are working around or on the module, and to serve as a backup for electrical instrumentation. Electrical instrumentation is used at appropriate points in the cycle for control purposes and for data monitoring purposes. The electrical instrumentation consists of two-wire transmitters that supply 4 to 20 ma signals through intrinsic safety barriers to a data recording system and to digital readouts.

Those signals which are not used for control purposes are fed directly to the data system. Signals which are used for both process control and data logging are fed to the appropriate process controller, the calculator and, in most cases, to a digital readout in a series string. The data system is controlled by an HP 9825S calculator which interfaced with a CDS53A scanner. All instrumentation signals are fed into five 20-channel cards in the CDS53A. The calculator selects a channel on a card either automatically when scanning or on command from the operator and routes it to the NP 3437A system voltmeter. The voltmeter is read by the calculator, which displays the value, prints it out, or stores it. The data system is defined by the block diagram, Figure 11. All instrumentation signals which are displayed on the console use digital Doric 400A indicators.

The instrumentation data system was designed to provide three basic services:

1) It provides a continuous realtime readout of loop parameters using single-channel and multi-channel digital readouts,

2) It continuously records data to provide a permanent and formal record of loop parameters versus time, and

3) It reduces data for immediate evaluation of system performance.

4.4.2 Data Reduction

The data reduction software provides two basic functions: continuous logging of data while other programs are run, and data reduction summaries for immediate evaluation of system performance. In addition, programs allow the operator to:

Clear all data files off the system disk
Set the realtime clock
Change the transducer names and channels
Calibrate channels
Examine transducer voltages
Examine transducer readings
Print the time
Examine the time
Analyze noise voltages
Change data reduction constants
Change test information
Print a previously recorded data set.

4.5 FIRE PROTECTION AND VENT SYSTEM

The large quantity and multiple locations of the IC_4 in the plant required that the whole plant be designed with a comprehensive approach to fire safety. Plant safety was achieved in several design steps. All sources of ignition have been removed by properly protecting all electrical sources. Vessels, their supports and larger plumbing have all been provided fire protection. Additionally, pressure design limits and a remote vent system for tank relief valves were incorporated to prevent venting of IC_4 near any working areas of the plant or facility.

Fire protection consists of insulation of IC_4-containing vessels and their support structures, fixed monitors, fire hoses, and fire extinguishers. The condenser supports are protected by water spray. The primary objective of this protection is to provide time for safe evacuation of all personnel. The basis for the fire protection system is NFPA No. 58, Standards for the

Storage and Handling of Liquefied Petroleum Gases, Chapter 3, Installation of Liquefied Petroleum Gas Systems, 3912, 3914, 3920 and 3924; California Administrative Code, Title 8; General Industry Safety Orders, Article 147; Bulk Plants, Section 5624; Fire Control and Article 148; Refineries, Chemical Plants, Wineries and Distilleries, Articles 156, 157, 158, 160 and 163.

A fire pump and a 30,000 gallon tank, which is part of the test facility, will supply water to the plant's spray, monitor and hose systems. Switches to activate the fire pump are located near the control trailer on the plant pad and at the hydrant house of the Geothermal Component Test Facility. The pump is capable of providing 675 gpm at 126 psig from the 30,000 gallon storage tank, which allows a 45 minute water supply at maximum flow conditions.

There are nine fire extinguishers distributed in the pilot plant so that four are on the pad, two in the power module, two in the control module, and one at the storage module. In each case, the minimum extinguisher rating is 1A:80B:1C. These ratings and placements are in accordance with the California Administrative Code, Title 8, Chapter 4, Articles 156 and 157, pages 526.8.61 to 526.8.70, and NFPA Standard 10, Standard for Portable Fire Extinguishers, 1978. Dry chemical fire extinguishers are used per recommendation of NFPA Standard 59, Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants, Section 8, Paragraph 811.

An IC_4 detection system is set up with alarms to alert operators and to indicate the location of hazardous IC_4 concentrations. All persons on site will be notified over the PA system when any of the IC_4 detection alarms has been triggered.

The storage tanks and other vessels are not enclosed or diked so that IC_4 spills can be washed away from the vessels. In this manner the fire heat input into vessels and equipment can be reduced. Pad drainage is away from the existing facilities.

The vent system for carrying relief valve flow away from the plant consists of headers from the relief valves to a 10 inch diameter pipe extending 250 feet away from the plant and terminating at a seal drum. Vent stacks on the drum are designed to eject any received gases into the air at a high velocity to dilute the gases and enhance their dispersal. The drum and its vent stacks are located at a sufficient distance from the plant to ensure that even the highest potential gas venting rates will not result in a 50% of explosive mixture ratio reaching any part of the plant or East Mesa facility.

4.6 DOWNHOLE PUMP

A downhole pump was installed in East Mesa well number 8-1 to supply unflashed brine to the 500 kw plant. The pump is a Reda model G220 modified by Reda for geothermal application. The modifications include special high temperature oil, mechanical shaft seals in the motor protector, an oil expansion chamber and a special high temperature cable. The unit has an 80 hp motor with a 27-stage pump to produce 280 psi of pressure rise with hot water at 225 gpm. A similar unit was tested in a geothermal pump test rig for 30 days at 375°F prior to the well installation.

The pump is located at the 600 foot level and the fluid is produced through a three-inch production tube that suspends the pump unit. The well can be produced in the annulus between the production tube and the well casing when the pump is not operating. Production through the annulus can be used to keep the well and pump unit hot. The pump is operated continuously except for power outages.

4.7 POWER TURBINE

The power turbine purchased for the plant is a custom design by Mafi-Trench Corporation. The turbine is a radial inflow type, cantilevered off the high speed shaft of a two-stage gearbox. The cantilevered configuration was selected to eliminate the high speed bearing losses associated with a separate turbine wheel-shaft assembly. An oil-pressurized double seal isolates the working fluid from the gearbox and prevents air from leaking the other direction. The turbine, gearbox, alternator, lube oil system and controls are all mounted on a skid which is installed in the power trailer. Cooling water, air and electrical power are supplied externally to the unit for operation of the oil system and controls. The assembly is instrumented with pressure, temperature and speed limit switches for protection. The switches are all integrated with the plant control logic.

5.0 BASELINE TESTS AND RESULTS

Checkout and testing of the pilot plant followed a logical sequence starting at the component level moving up through subsystems and culminating with operation of the complete plant. The test plan followed the major steps outlined below and is documented in the "Baseline Test Plan".

- a) Proof and leak test of the system.
- b) Functional check of all control loops and logic.
- c) Calibration of instrumentation, data system and safety switches.
- d) Functional check of utility cooler and adjustment of component cooling flows.
- e) Flow brine through system, adjust process controls and check safety logic.
- f) Purge IC_4 portions of the system of all air.
- g) Check fire system and gas detectors and train crew for emergency procedures.
- h) Functional check of condensers.
- i) Fill system with IC_4.
- j) Bring up both brine and IC_4 loops and set remainder of process controls.
- k) Power up turbine-generator set speed controls and check

synchronization switchover.

l) Operate plant to determine performance potential.

5.1 PLANT FUNCTIONAL PERFORMANCE

The functional behavior of the plant and the various equipment was as expected with no major problems as they were brought through the various steps in getting them running. During the process of checking out the plant, the typical minor problems were encountered with instrumentation and control settings or adjustments, with logic interlocks or sequences and wiring errors. These minor problems were corrected as the checkout progressed and when the plant was brought up the majority of the systems performed well. The closed loop controls, operational logic and the process dynamics are all relatively well-balanced and predictable, thus producing a plant that is easy to start and operate. The protective logic for the plant was demonstrated by various upsets during the adjustment phase. Automatic shutdown does not cause any undesirable transients or system problems and the plant can be restarted as soon as the fault causing the shutdown is cleared.

Two of the control loops require some modification to achieve their design goals. The flow control loop for the IC_4 to the DCHX is designed to hold a fixed ratio to the brine flow. This loop cannot be used as designed due to the very noisy signal being received from the brine flowmeter. Interim operation will require manual adjustment of the IC_4 flow whenever a brine flow rate is reset. The superheat control for the binary heat exchanger is the other control loop requiring modification to meet design goals. Control is achieved for the binary heat exchanger by controlling the temperature produced in a throttling calorimeter. The plumbing associated with the calorimeter acts as a large heat sink which prevents the control loop from getting the error signal it needs. The control does not affect basic plant operation and the heat exchanger can be operated manually. The modifications required to these two loops will be developed and installed in the next phase of testing.

After the process loop had been checked out and was operating properly, the turbo-generator was checked out. It was brought up to operating speed in steps with its subsystems and general operation monitored with no indications of problems. After a short period of operation at design speed there was an incident indicating distress in the rotating machinery which appeared to clear up. Flow rate to the turbine was increased but there were indications that power output was decreasing. Instrumentation problems prevented an accurate measurement of delivered power but amperage readings which had reached 400 amps at low flow levels were down to 300 at high input flow levels. Turbine testing was terminated when it became apparent that no power was being produced. Removal of the housing showed that a major percentage of all the blades was missing. Initial evaluation of the failure attributed the blade loss to liquid slugging and intermittent high levels of water entrainment in the IC_4 vapor flow to the turbine. Subsequent testing of a second wheel, which failed in less than 10 minutes, indicated that the failure was not related to liquid problems. The water and liquid entrainment problems were corrected by plant changes. The high level of brine carryover was fixed by repositioning the DCHX brine inlet at the proper level in the column. The original positioning was in error, being too close to the top of the column and the level control was not maintaining the proper level control with respect to the inlet. To eliminate the collection of liquid in the turbine inlet line before startup, a drain was incorporated in front of the turbine shutoff valve.

5.2 PLANT SYSTEM AND COMPONENT PERFORMANCE

The data taken during baseline testing indicates that the DCHX performance exceeds design with good heat transfer and very small pinch point differential. The column is stable without internals and appears to have the performance potential required. Qualitative effects of CO_2 levels were not established but condensing pressures were less than those experienced with the small scale tests. The analytical plant model was run with the actual brine temperatures and condensing conditions to develop a qualitative feel for potential system performance. Component efficiencies used were those predicted by the vendors or previous analysis. The largest difference between design conditions and actual test conditions is the brine inlet temperature to the DCHX which dropped from 335 to 314°F. As can be seen in performance printout, Figure 12 , the predicted power level for 314°F brine has been reduced from a net of 500 kW to 412, and the source production factor has dropped from 5.1 watt-hr/lb brine to 4.3. The power drop and the reduction in production factor would have been more severe if the higher design condensing temperatures had been encountered.

The evaluation of the various component performances gave no indication that any portion of the system would not be capable of achieving design goals. The subsequent paragraphs in this section discuss the performance of major components where they could be evaluated. Typical performance data sheets for three flow conditions evaluated are attached.

5.2.1 Downhole Pump

An electric submersible downhole pump was used to support the 500 kW pilot plant. The pump was selected to provide a nominal flow rate of 225 gpm and a minimum manifold pressure of 200 psig at 250 gpm. The pump was installed in well Mesa 8-1 on August 21, 1979. After 34 days of operation a motor failure occurred due to brine leakage past the motor seals and the protector. Following a redesign of the protector and refurbishment of the motor, a second pump was installed in the production well. This unit began operation on November 17, 1979, and operated for 5.5 months before motor problems caused the unit to shut down. During this period the unit shut down 10 times due to power failures and restarted with no problem.

Initial estimates of well pressure flow characteristics were based on well production indices of 1.54 to 2.28 gpm/psi. These indices were used in sizing the downwell pump. During pump operation a higher manifold pressure than anticipated was measured, implying a higher well production index. Measured manifold pressure data is shown as a function of pump flow rate in Figure 13. As noted on the figure, the manifold pressure corresponds closely to that predicted, assuming a production index of 4.0 gpm/psi. The data shown on the figure has been repeatedly verified during operation with the 500 kW pilot plant. Brine temperatures in the manifold at the plant interface have been holding at 319°F which is at least 21°F below the temperature expected. At present there are no explanations for the lower well head temperatures.

5.2.2 Flash System and Binary Heat Exchanger Performance

The partial flashing of brine in the sand trap to remove excess CO_2 from the brine was performed. Temperature drop was measured as the difference between inlet and discharge temperatures from the flash tank. Calculations based on the tank exit temperature and tank pressure, assuming a CO_2-water vapor mixture, indicate that the brine to the DCHX was run at CO_2 level concentrations ranging from 150 to 425 ppm.

Condenser performance was evaluated to determine the effect of the CO_2 concentration. The data showed no apparent correlation with the calculated levels of CO_2 but did show a smaller performance loss than earlier small scale tests. Condenser performance is discussed further in a subsequent section. Additional testing with measured CO_2 levels will be performed under the follow-on test plan.

Binary heat exchanger performance was not analyzed because of the lack of usable data. The control loop was inoperative due to the poor thermal response of the throttling calorimeter and inability to set and hold proper operating conditions. The heat exchanger was capable of condensing the flash steam and will work satisfactorily when the control loop is corrected.

After testing, the sand trap was opened for inspection of carbonate deposits and readjustment of the flashed brine temperature probe. The inspection showed an accumulation of deposits at the bottom of the tank and a small layer of deposit on all the surfaces covered by brine. The screen protecting the pump inlet was blocked almost 100% by deposits and ruptured. A pressure drop of 10 psi had been observed across the screen just prior to its failure. Chemical analysis of deposits scraped off deswirling vanes at the tank exit showed the deposit to be 97.3% by weight $CaCO_3$. Evaluation of the material removed from the bottom of the tank showed a high concentration of sand, approximately 71.2% silicon dioxide (SiO_2).

5.2.3 Brine Boost Pump

Measured performance of the brine boost pump is very close to that predicted by the vendor. Head-flow measurements made during system testing are plotted on Figure 14 which also shows the vendor's predicted head-flow curve. A review of electric parasitic power data shows that the input power levels span the calculated or predicted power consumption. The differences are close enough to indicate that pumping efficiency is approximately 75%.

5.2.4 Direct Contact Heat Exchanger

Based on measured flow rates and column temperatures, heat transfer and heating curves for the DCHX were derived. Heating curves for low, medium and high IC_4 flow rates are shown in Figures 15, 16, and 17. These curves are based on temperature probes located the length of the column (see Figure 18). The heat transfer rates achieved ranged from about 11×10^6 Btu/hr at the low flows to 17×10^6 Btu/hr at high flows. Brine to IC_4 flow ratios were maintained at approximately 1.85:1 and overall heat balances of 93% or better were consistently achieved based on the recorded data. The most significant aspect of the data is the indicated low pinch temperature differences achieved over the entire operating flow range. While the expected pinch temperature at plant design conditions was 7°F, the pinch temperature differences calculated at the actual conditions ranged from a low of 1.1°F at high flow rates to a high of 3.7°F at low flow rates. No attempt was made to flood the column to determine its operating limits. The lower brine temperatures being used in the DCHX theoretically would allow a shorter column to be used. The temperature distribution measured in the column supports the potential of using a shorter column, thus tending to verify part of the column design criteria. The heat transfer coefficients are difficult to calculate because of the low pinch differentials. A small error (one degree or less) in the true pinch temperature has a magnified impact on the heat transfer coefficients being calculated.

The low pinch differential indicates that the flow is very stable and no back-mixing is occurring. Evaluation of column performance parameters and verification of design criteria will depend on further testing with adjusted configurations and design operating conditions.

5.2.5 Recovery System

The various components in the recovery system functionally performed to expectation. Tailstock flashing pressure was adjusted from the original design value of 17 psia to approximately 30 psia. This change was necessary in order to handle larger flow transients from the tailstock. At the lower pressure level, upset conditions within the system would result in flooding the tailstock and shutting down the loop. The recovery compressor held the recovery tank pressure at the 5 psia level even with higher than 50 ppm calculated levels of CO_2 concentration in the brine. These pressure levels tend to verify the predictions of stripping versus compressor capacity. An evaluation of recovery performance and the level of IC_4 in the discharged brine must wait for test runs where good samples and accurate chemical analysis are available.

5.2.6 Hydrocarbon Power Turbine

The power turbine installation was checked out for operation by Barber-Nichols and Mafi-Trench personnel. The installation proceeded smoothly and no problems were encountered with the control interfaces, lube system or seal pressurization. The turbine was started initially on January 15, 1980. Between the 15th and the 18th, the turbine was started a total of five times with a total run time of 13 hours 30 minutes.

During these runs the generator power ouput was obtained by monitoring generator amperage. These values appeared reasonable at startup and for about 1.5 hours into the run. At this point, increases in turbine flow rate resulted in no further increase in generator output. For the remainder of the test runs, the generator output continuously declined.

Disassembly and inspection of the turbine revealed an obvious failure. The turbine blades were broken and the bearing and seals received considerable damage. A potential cause of the failure was thought, at first, to be liquid hitting the turbine at startup. The turbine inlet line from the DCHX has a vertical run downstream of the bypass line which allowed liquid to collect due to condensation and some carry-over. Carry-over was evidenced during early runs by an increase in hotwell conductivity. When the turbine start valve was opened, this column of liquid was forced through the turbine rotor. The turbine was slugged with liquid on three separate occasions.

Modifications were subsequently made to the pilot plant to avoid water carry-over. These included lowering the brine inlet to ensure that the free surface level in the DCHX would remain above the brine inlet and installing a bypass line to prevent collecting liquid upstream of the turbine. A second start attempt with a new turbine rotor was made. A turbine blade failure was encountered within approximately 10 minutes after operating speed was reached. Comparing the two failed rotors revealed that the same mechanism was responsible for both failures. Strong evidence of blade fatigue due to high stress and blade vibration existed in both turbines and no evidence of plastic yielding was found at the initial blade separation point. It was concluded that the turbine mechanical design is at fault rather than operating conditions encountered with the DCHX. The turbine design is presently being modified to change the blade natural frequency and to reduce the steady-state bending stresses in the blades. The design conditions for the 500 kW power turbine are well within reliable operating ranges for well-designed rotors so this turbine problems is not felt to be signficant.

5.2.7 Evaporative Condensers

The evaporative condenser performance was evaluated on the basis of calculated heat transfer and the measured condensing pressure. The heat transfer and condensing pressure performance are dependent on good hardware design and selection, and are also a function of the non-condensibles transferred to the IC4 from the brine. Figure 19 shows the heat transfer performance plotted as the difference between the condensing temperature and ambient wet bulb temperature versus the condenser heat load. Data is plotted using both the hotwell temperature and the condensate temperature as the condensing temperature. Projected condenser performances at various wet bulb temperatures are shown for comparison. This graph indicates that the condensers were able to dissipate a greater heat load than was projected for the wet bulb temperatures (48 to 54°) encountered during testing.

Condensing pressures versus condensing temperatures are plotted in Figure 20 with projected condenser conditions for various CO_2 concentrations in the brine entering the DCHX shown for comparison. Data from previous 10 kW test programs using tube-and-shell hardware is also shown (Ref. 8).

Actual levels of CO_2 concentration in the brine during these tests are not known. Using calculated levels of CO_2, based on flashing conditions, there was no correlation with recorded condensing pressures. The data used was taken with periods of only a few hours at most for system stabilization and it may be that much greater time intervals are required for the CO_2 level in the condenser to reach equilibrium. In preparing the system for use, CO_2 is used to purge the condensers and it is possible that there was a higher level of CO_2 present during the test than would be found at equilibrium conditions. Future testing will establish the equilibrium conditions and attempt to correlate CO_2 levels with condensing pressure.

5.2.8 Hotwell

The hotwell has two functions and is separated into two chambers by a weir in the tank. The first section is used to separate the condensed water from condensed IC_4 and the second section is used to provide inventory storage for the IC_4. The water separation section appears to be functioning well. Sampling from the bottom of the storage section shows only trace amounts of water collection. It is felt that most of the water appearing on the storage side is being condensed from input flow through the equalization line.

5.2.9 IC_4 Feed Pump

The IC_4 feed pump was calibrated against the system flowmeter and the ΔP transducer across the pump to develop a head-flow curve. Figure 21 presents the predicted head-flow curve and the data obtained with the system instrumentation. The predicted head-flow curve is based on data developed by the manufacturer with a half-speed water test. The discrepancy between the system data and the corrected vendor's data cannot be accounted for at this time. An attempt has not been made to isolate the required input electrical power for the pump but based on a comparison between calculated system input power levels and the measured levels, it appears that the actual efficiencies are close to the predicted efficiency.

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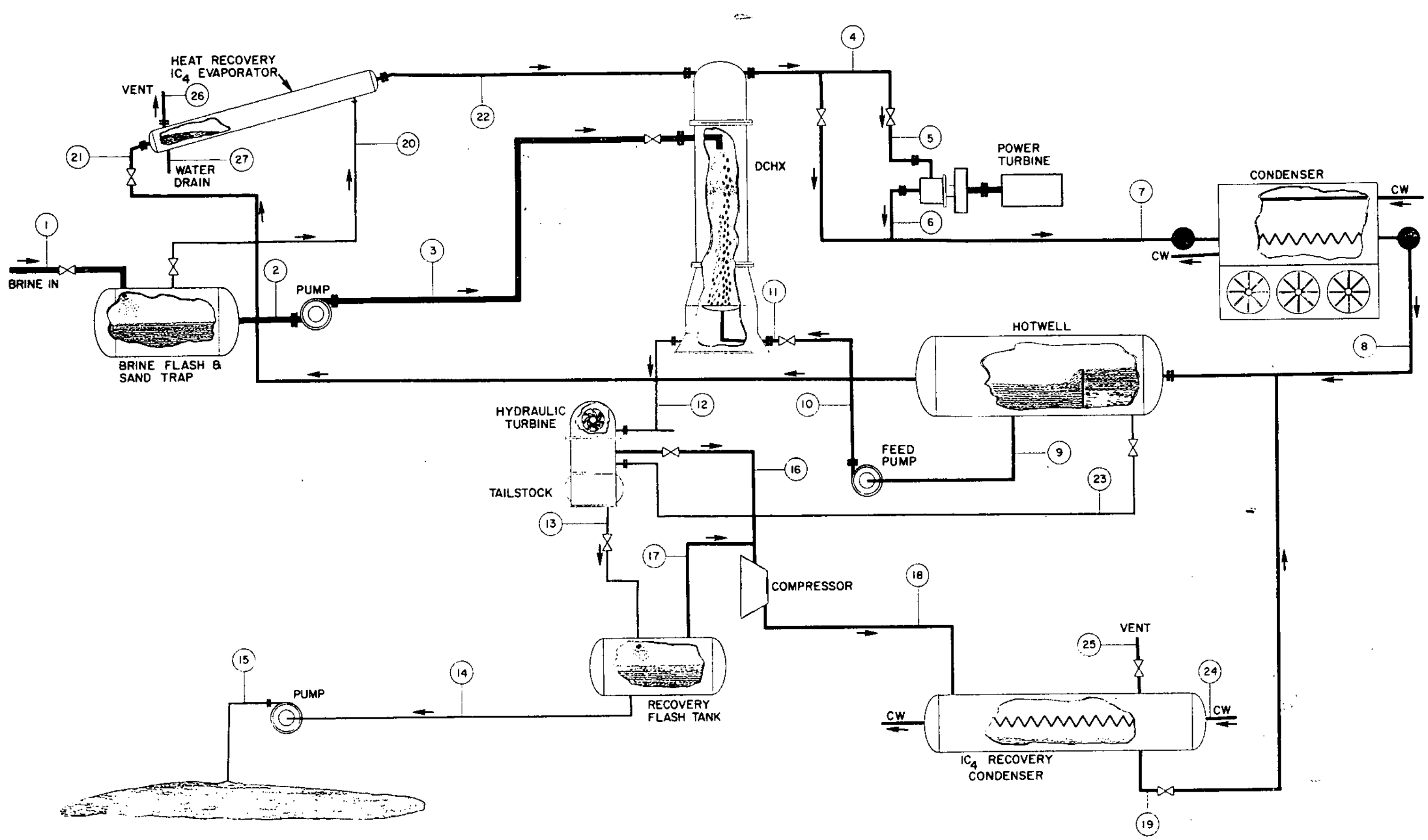

MATERIAL BALANCE

PROCESS STREAM NUMBER

STREAM / PARAMETER	1 GEOTHERMAL BRINE SUPPLY	2 GEOTHERMAL BRINE TO BOOST PUMP	3 GEOTHERMAL BRINE TO DCHX	4 ISOBUTANE VAPOR FROM DCHX	5 ISOBUTANE VAPOR TO TURBINE	6 ISOBUTANE VAPOR TO CONDENSER	7 CONDENSER INLET	8 ISOBUTANE CONDENSATE TO HOTWELL	9 ISOBUTANE LIQUID TO FEED PUMP	10 ISOBUTANE LIQUID FROM FEED PUMP	11 ISOBUTANE LIQUID TO: DCHX	12 GEOTHERMAL BRINE FROM DCHX	13 GEOTHERMAL BRINE FROM HYD. TURBINE	14 RETURN BRINE
FLOW RATE (lb/hr x 10^3)	97.8	97.2	97.2	99.4	99.4	99.4	99.4	99.4	98.0	98.0	95.4	95.8	97.2	97.2
TEMPERATURE (°F)	340	335	335	255	253.4	140.6	140.6	94.0	94.0	95.0	95.0	148.8	144.8	144.8
PRESSURE (PSIA)	175	118	485.0	452.7	442.7	72.0	71.6	70.0	70.0	485	467	457	17.0	5.0
ENTHALPY (BTU/LBM)	311.4	306.1	306.6	-581.0	-581.0	-607.7	-607.7	-776.1	-788.9	787.2	-787.2	114.1	112.98	112.98
DENSITY (LBM/FT²)	56.0	56.1	56.2	6.46	6.32	0.692	.688	34.0	33.8	33.8	33.8	61.4	61.3	61.3

STREAM / PARAMETER	15 RETURN BRINE	16 VENT FROM TAILSTOCK	17 VENT FROM RECOVERY FLASH TANK	18 FLOW TO RECOVERY CONDENSER	19 CONDENSATE FROM IC_4 RECOVERY CONDENSER	20 STEAM & CO_2 TO EVAPORATOR	21 IC_4 TO EVAPORATOR	22 IC_4 FROM EVAPORATOR	23 WATER CONDENSATE FROM HOTWELL	24 COOLING WATER TO IC_4 RECOVERY CONDENSER	25 IC_4 RECOVERY CONDENSER VENT	26 IC_4 EVAPORATOR VENT	27 IC_4 EVAPORATOR DRAIN
FLOW RATE (lb/hr x 10^3)	97.2	.011	.018	.029	.023	0.629	2.6	2.6	1.4	16.0	.006	.140	.489
TEMPERATURE (°F)	144.8	144.8	144.8	250	76	335	95	260	94	74	76	270	225
PRESSURE (PSIA)	20.0	17.0	5	90	90	95	485	460	17	—	90	95	95
ENTHALPY (BTU/LBM)	112.98	—	—	—	—	417.3	-787.2	-610.8	62.0	42.0	—	—	—
DENSITY (LBM/FT²)	61.3	—	—	—	—	.224	33.8	7.0	62.1	62.3	—	—	—

Fig. 1. Process flow diagram of 500 kW direct contact pilot plant.

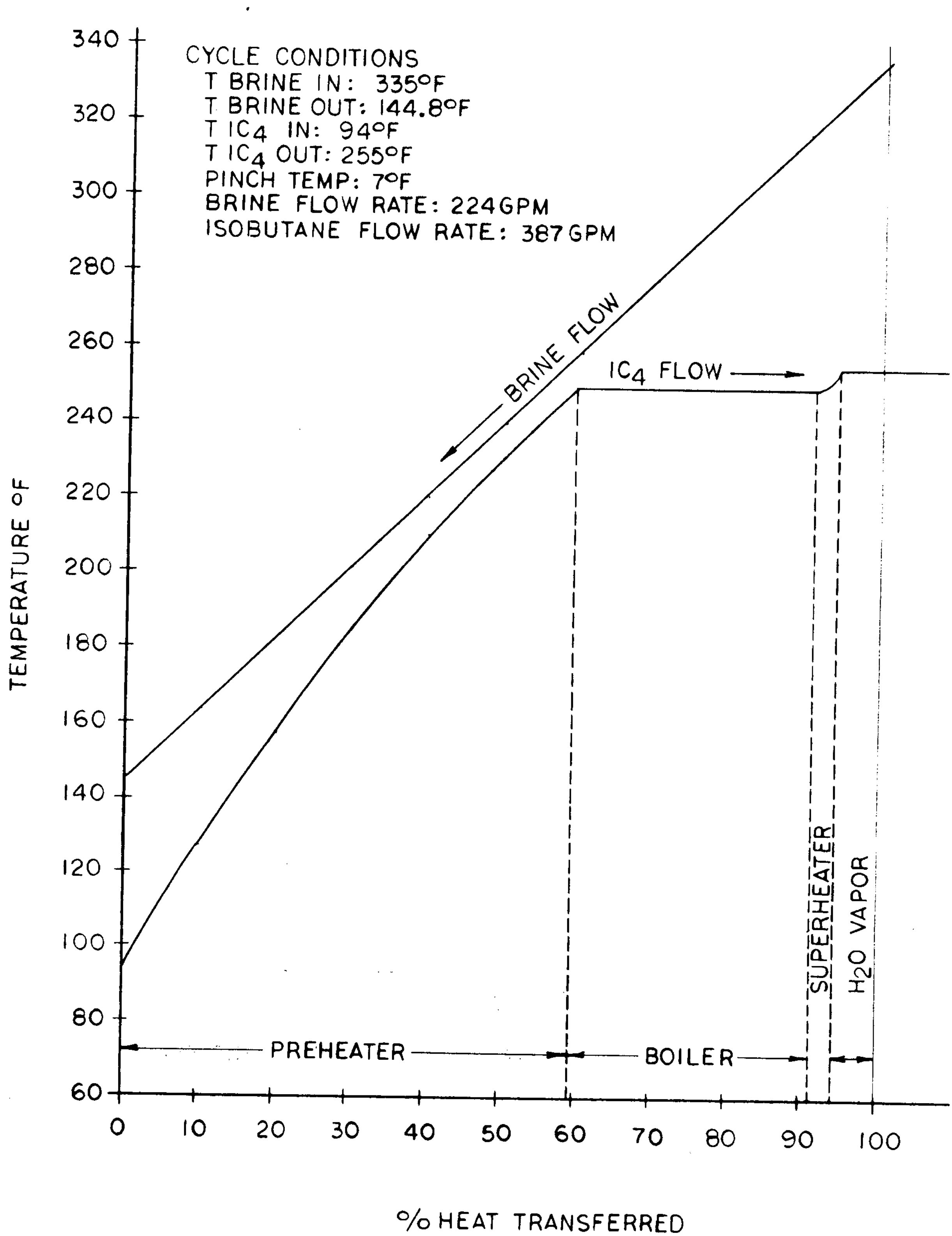

Fig. 2. DCHX heating curve for pilot plant design point conditions.

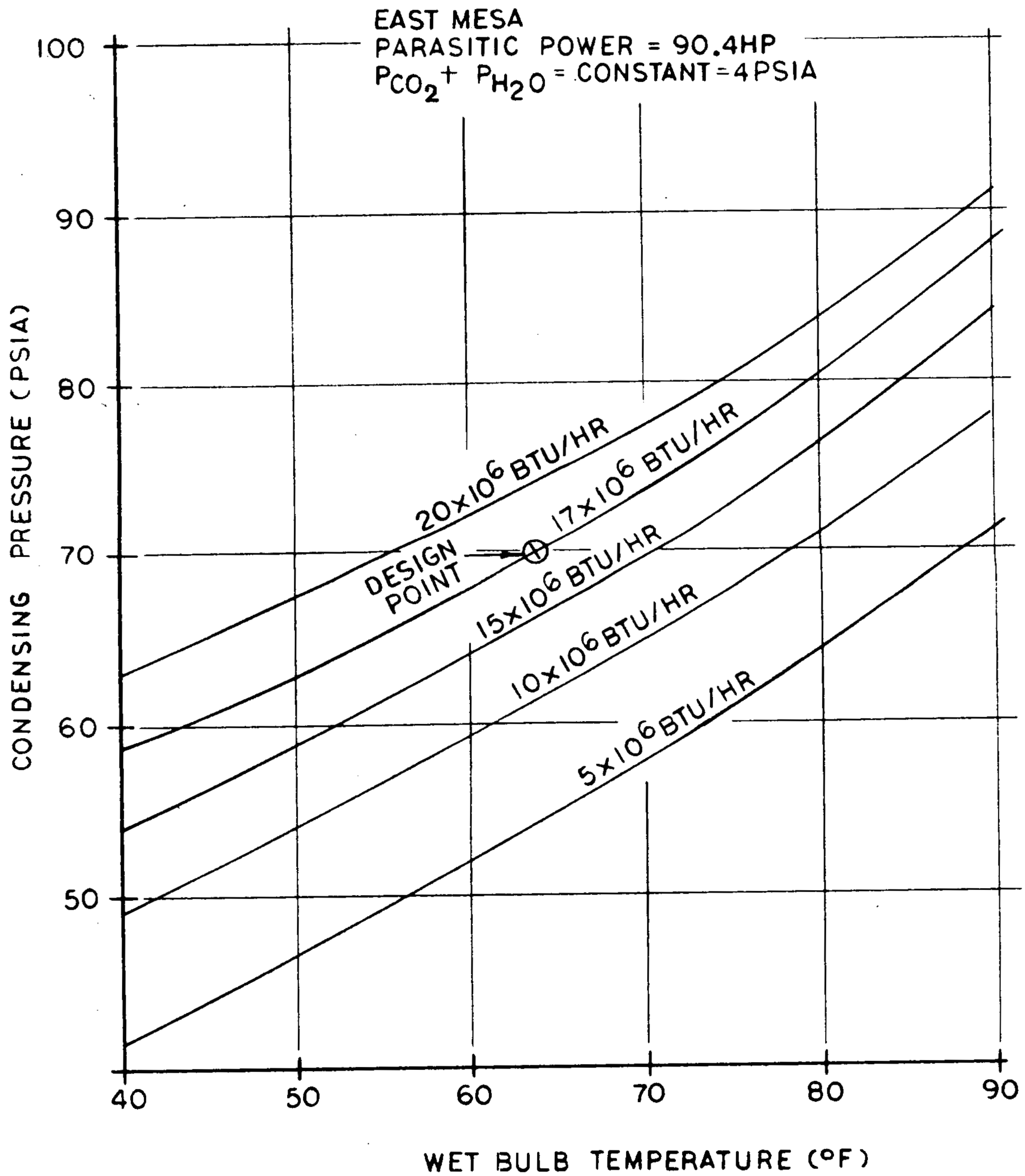

Fig. 3. Effect of wet bulb temperature on condenser pressure at given heat loads.

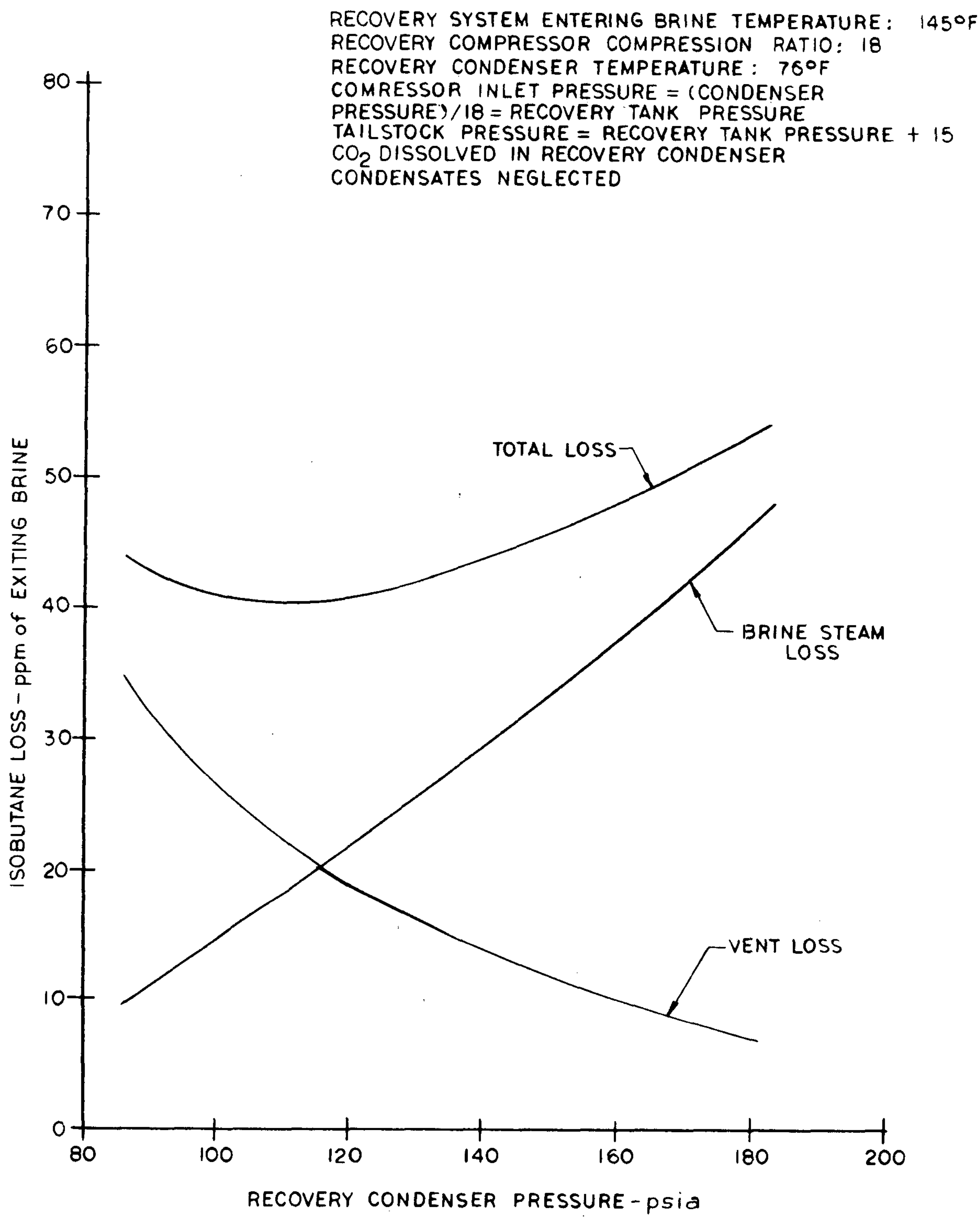

Fig. 4. Predicted isobutane recovery performance.

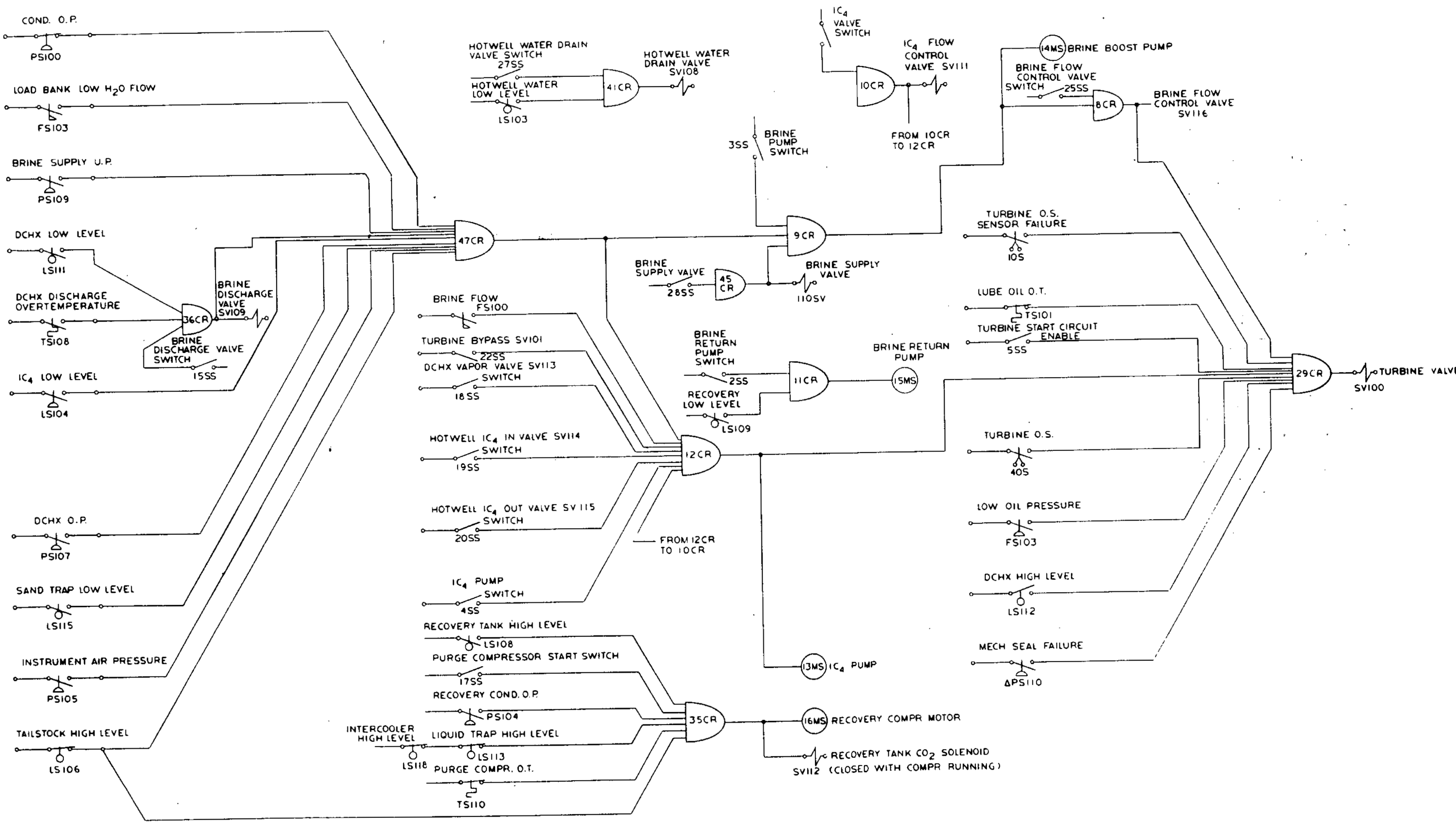

Fig. 5. Pilot plant operational logic block diagram.

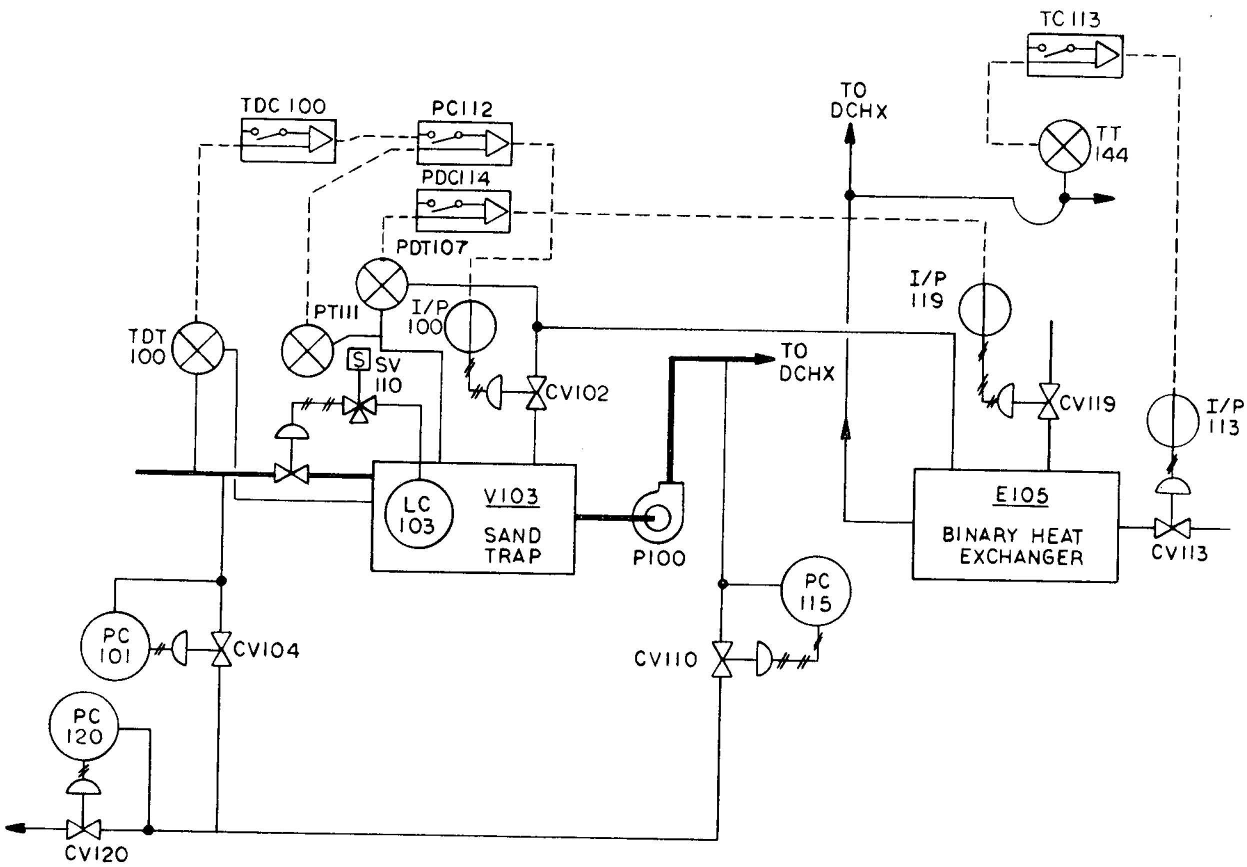

Fig. 6. Sand trap and binary heat exchanger process control.

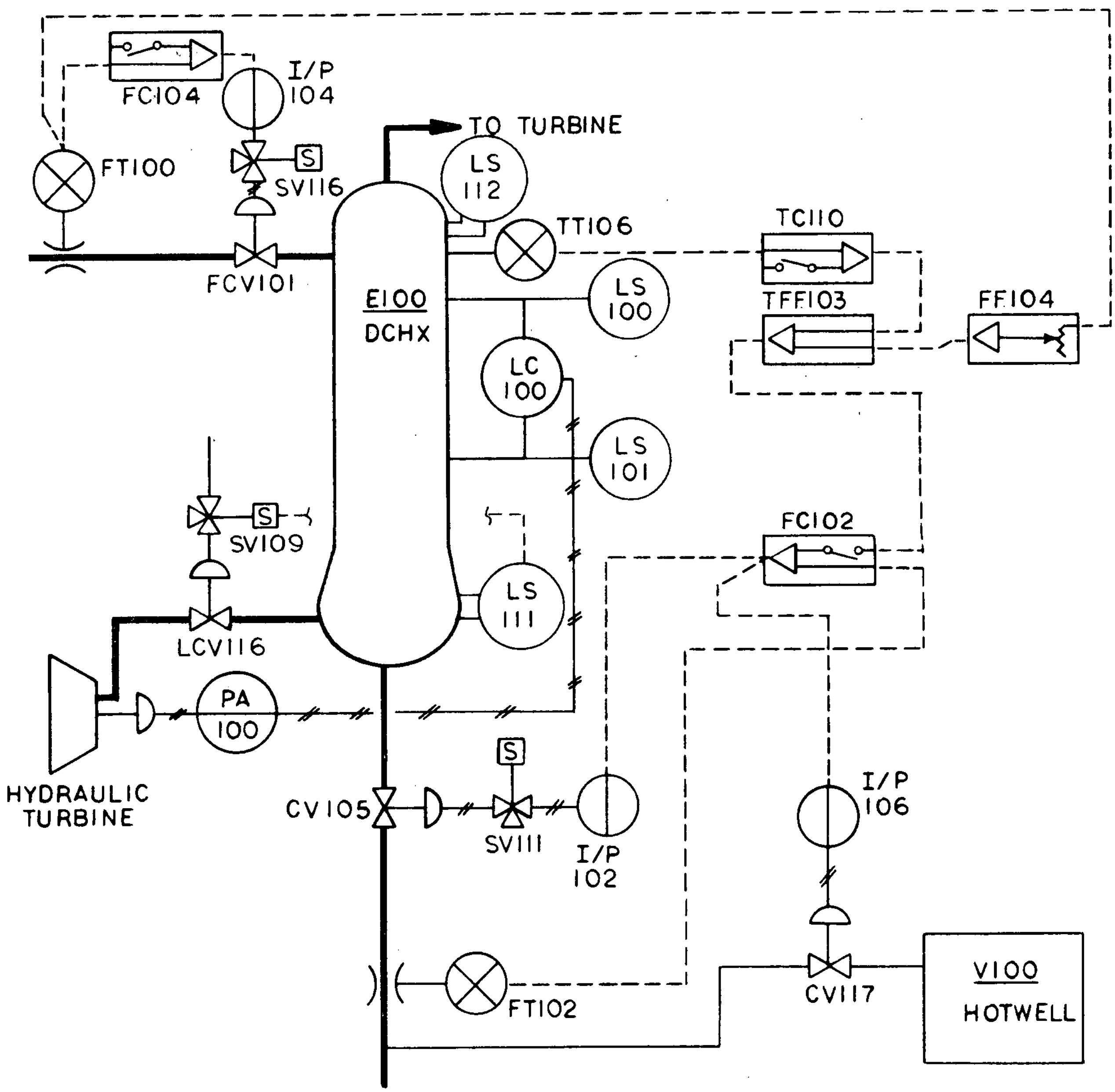

Fig. 7. Direct contact heat exchanger process control.

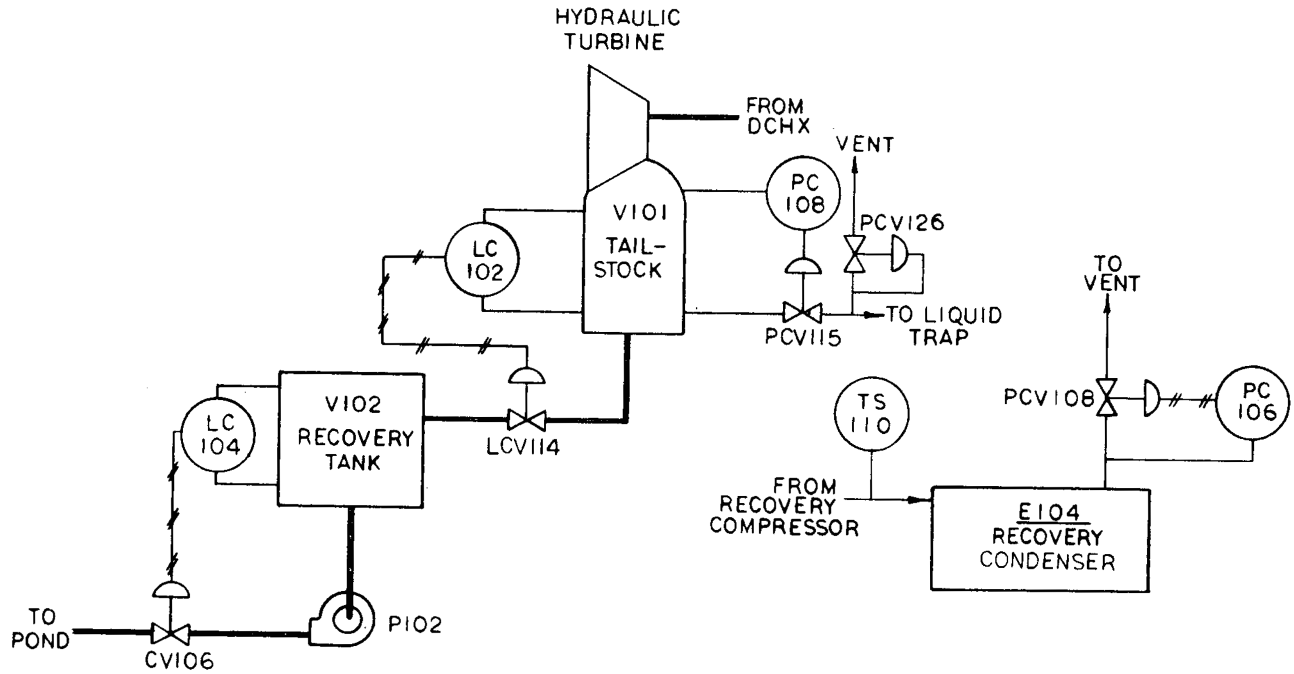

Fig. 8. Tailstock and recovery system process control.

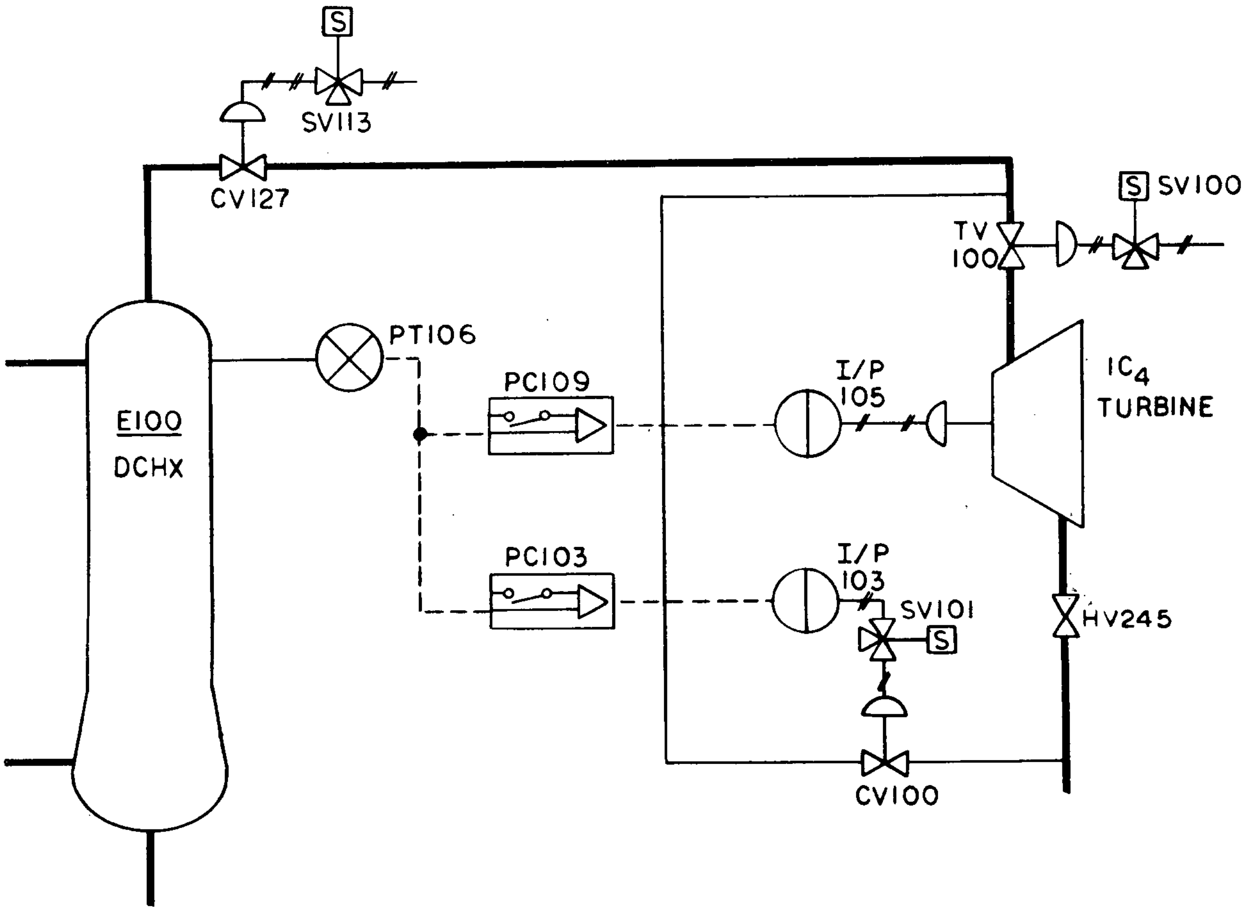

Fig. 9. IC_4 turbine process control.

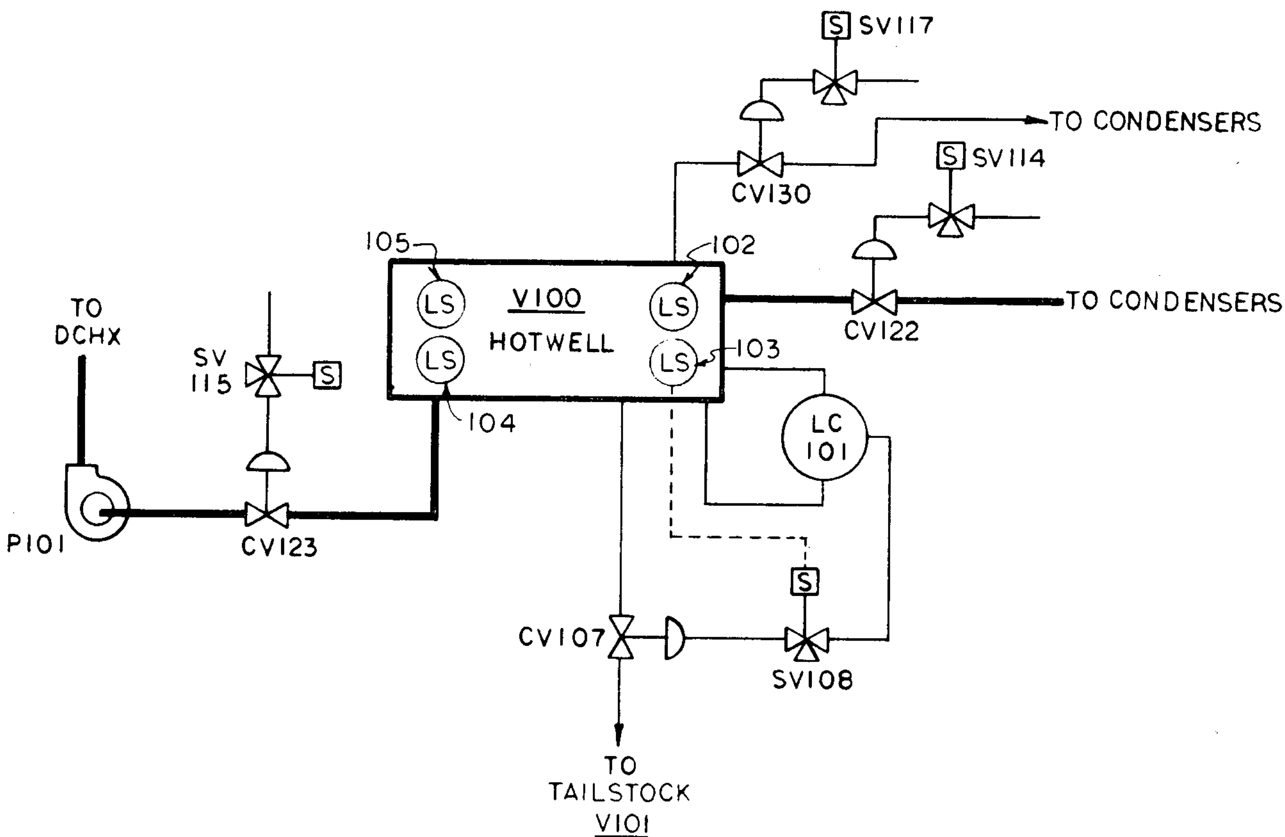

Fig. 10. Hotwell process control.

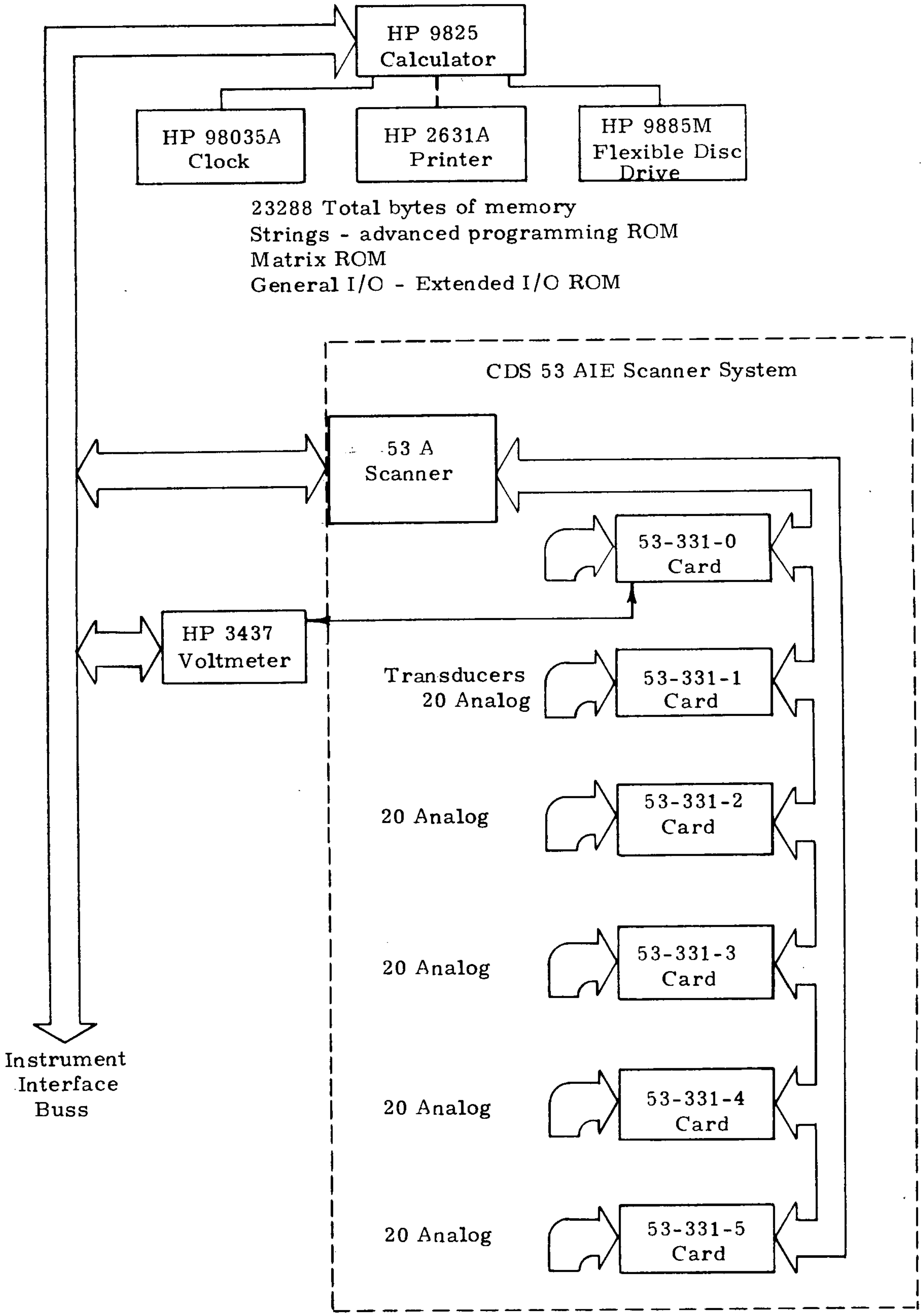

Fig. 11. Data collection and reduction system diagram.

Superheated; Organic Pressure=298.8		
Working Fluid:	Isobutane/H2O	
Brine Temperature In (F):	314.50	
Brine Pressure In (psia):	303.40	
DCHX Temperature (F):	236.70	
DCHX Pressure (psia):	322.39	
Condenser Temp. (F):	79.0	
Condenser Pressure (psia):	55.9	
Turbine Inlet Pressure (psia)	312.4	
Working Fluid Organic Fraction:	0.982	
Working Fluid H2O Fraction:	0.018	
Isentropic Analysis:		
Turbine Exit Temperature (F):	137.3	
H2O Turbine Exit Quality (Pct):	79.8	
Enthalpy Drop Across Turbine (Btu/lb):	32.5	
Brine Temperature Drop (F):	171.85	
Working Fluid Flow Rate (lbs/sec-gpm):	21.9-	285.5
Brine Flow Rate (lbs/sec-gpm):	26.4-	211.6
Density of Organic Liquid at Condenser Temp (lb/cf):	34.49	
Heat Transfer In DCHX (Btu/lb-Pct of Total):		
Preheat Organic:	88.6- 43.0	
Vaporize Organic:	88.7- 43.1	
Superheat Organic:	13.5- 6.5	
Vaporize H2O:	15.4- 7.5	
Total:	205.9-100.0	
Heat Transfer In DCHX (MBtu/hr):	16.26	
Heat Transfer In Condenser (Btu/lb-Mbtu/hr):	185.2-	14.63
Energy Generated In System (Kw-Pct of total generated):		
Gas Turbine:	623.9- 96.7	
Hydroturbine:	21.5- 3.3	
Total	645.3-100.0	
Parasitic Losses (Kw-Pct of total generated):		
Gear Box and Alternator:	49.0- 7.6	
Condenser:	74.6- 11.6	
Organic Feed Pump:	54.0- 8.4	
Brine Boost Pump:	38.6- 6.0	
Brine Discharge Pump:	2.1- 0.3	
Recovery System:	15.0- 2.3	
Total:	233.3- 36.2	
Net Energy (Kw-Pct of total generated):	412.0- 63.8	
Cycle Efficiency (Pct):	8.6	
Source Utilization Efficiency (Pct):	37.1	
Source Production Factor (Kw-hr/lb brine):	4.34(x.001)	
Turbine Efficiency (Pct):	83.0	
Actual Turbine Exit Temperature (F):	143.5	
Actual H2O Exit Quality (Pct):	94.7	
Actual Enthalpy Drop Across Turbine (Btu/lb):	27.0	
Volumetric Flow Rate at Turbine Exit (cfs):	40.9	

System Pressures (psia)--Refer to System Flow Sheet:

Location	Pressure	Location	Pressure	Location	Pressure
1	303.4	7	57.5	13	17.0
2	83.1	8	55.9	14	5.0
3	354.7	9	55.9	15	20.0
4	322.4	10	354.7		
5	312.4	11	336.7		
6	57.9	12	336.7		

Fig. 12. Predicted pilot plant performance with 314^{o}F brine.

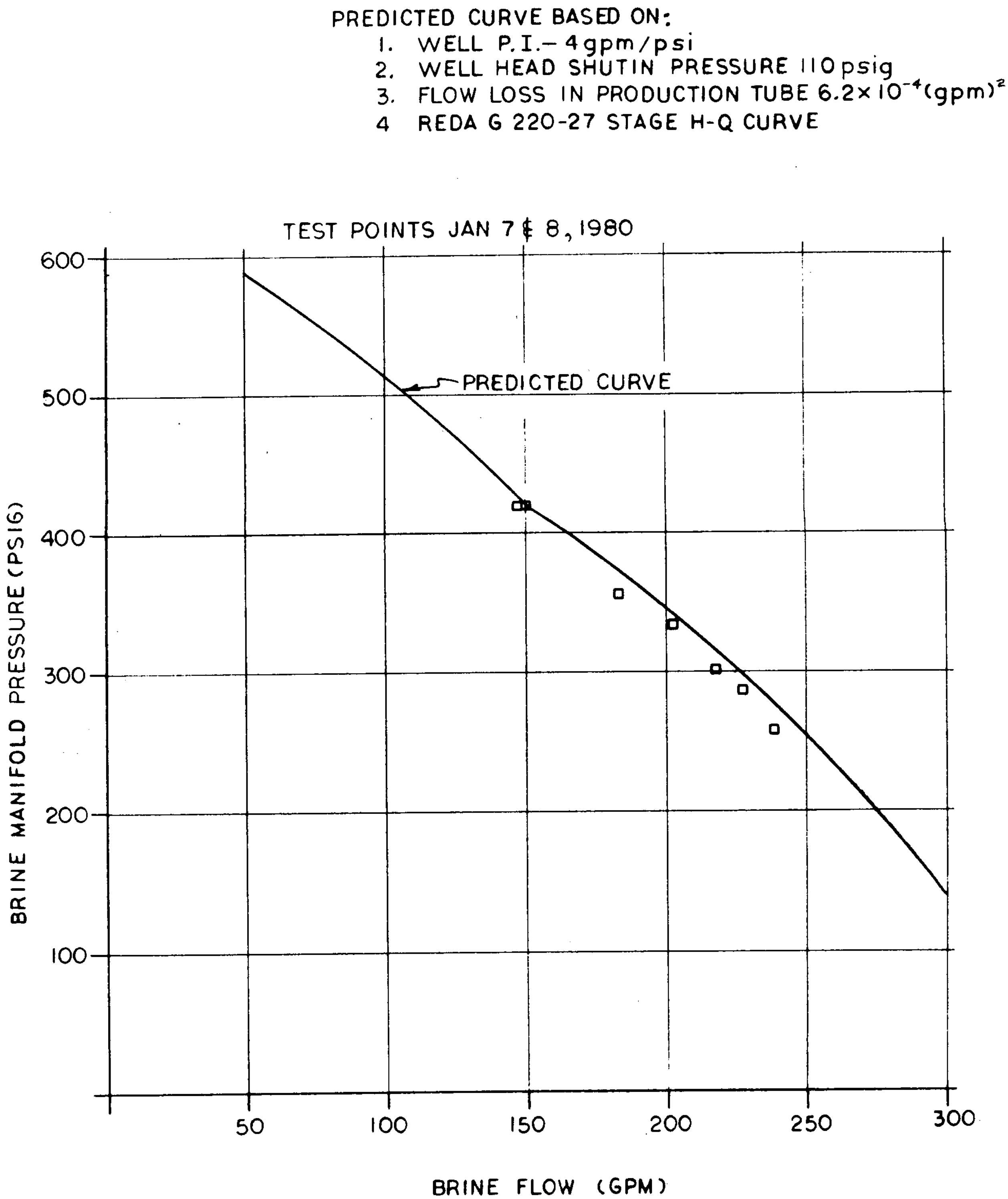

Fig. 13. Well 8-1 manifold pressure with REDA G-22 pump.

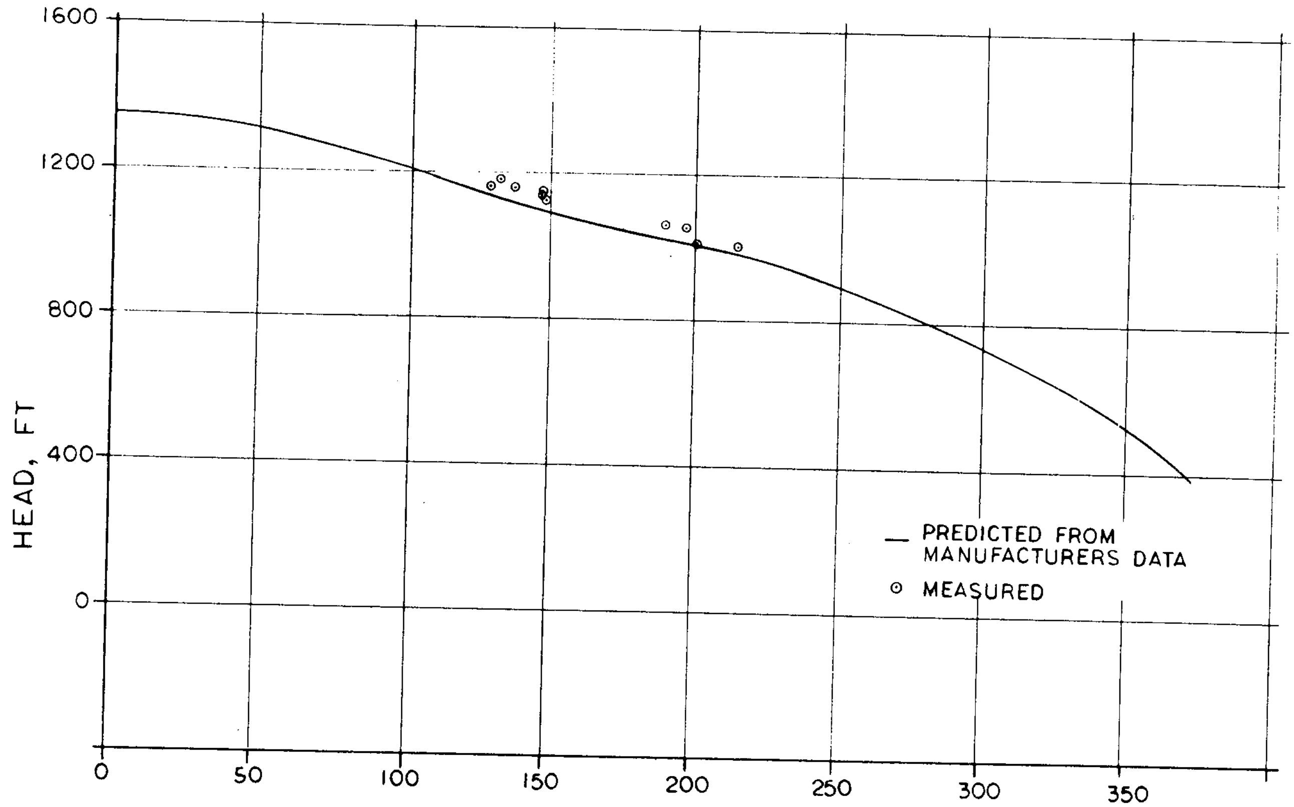

Fig. 14. Comparison of measured and predicted performance of brine boost pump.

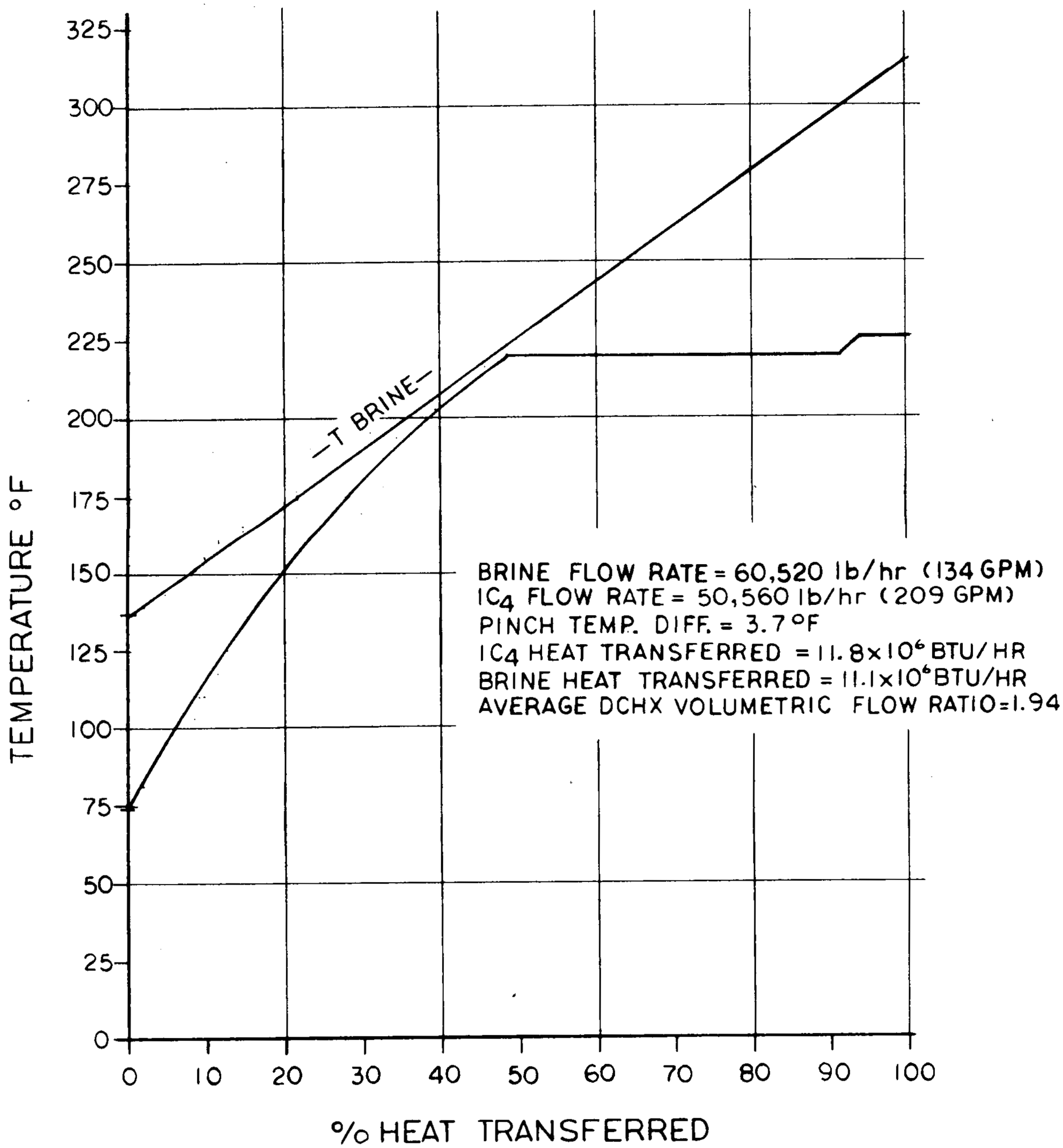

Fig. 15. Low flow case DCHX heating curve. January 18, 1980, 10:52 a.m.

Baseline Test

18 Jan, 1980 10:52:00

Operator = RGO

BRINE DELIVERY / FLASH SYSTEM

Manifold Brine P	DH Pump Disch T	Brine Flash DF T	Brine Flash P	ST Brine Out T	Brine Pump DF P
298.5psig	320.7F	3.7F	81.2psig	315.4F	394.8psid

HEAT RECOVERY LOOP

CV DifferentialP	Sand Tr Vent T	Steam Vapor Flow	Steam Condense P	IC4 Liquid Flow	Bin HX IC4 Out T	IC4 Vapor Pressu
27.9psid	292.2F	N.A.	49.4psig	N.A.	172.1F	16.9psig
Calorimeter T						
77.7F						

DIRECT CONTACT LOOP

Brine Flow In	DCHX Brine In T	DCHX Brine Out T	IC4 Liquid Flow	IC4 Press In	DCHX IC4 In T	Column Pres Out
134.3gpm	313.5F	137.2F	208.8gpm	331.4psig	82.9F	312.3psig
Column Diff Pres	Column Temp 1	Column Temp 2	Column Temp 3	Column Temp 4	Column Temp 5	Column Temp 6
0.7psid	226.2F	226.8F	227.1F	225.7F	225.2F	225.2F
Column Temp 7	Column Temp 8	Column Temp 9	Column Temp 10	Column Temp 11	Column Temp 12	Column Temp 13
215.9F	211.9F	206.5F	205.7F	200.2F	157.2F	156.2F
Column Temp 14	Column Temp 15	Column Temp 16	Column Temp 17	DCHX WF out T	Utility Cooler T	Gen Phase 1
180.8F	149.6F	143.2F	137.8F	225.5F	63.7F	N.A.
Gen Phase 2	Gen Phase 3					
N.A.	N. .A					

TURBINE AND POWER OUTPUT

WF Orifice Diff	Turbine Inlet P	Turbine Inlet T	Turbine Exit P	Turbine Exit T	Generator Output	Phase 1 Voltage
193.4IN H2O	318.7psig	221.7F	42.9psig	145.9F	N.A.	N.A.
Phase 2 Voltage	Phase 3 Voltage	Parasitic Power	Phase 1 Amps	Phase 2 Amps	Phase 3 Amps	Turbine Speed
N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

CONDENSER / HOTWELL

Condensate Temp	Hotwell Press	Hotwell Temp	IC4 Feed DF Pres
71.0F	41.0psig	74.9F	576.3psid

IC4 RECOVERY SYSTEM

Hydro Turb Dif P	Tailstock Press	Retn Pump In P	Comp In Press	Comp In Temp	Rec Comp Dsch T	Rec Condenser P
305.2psid	20.0psig	7.3psia	6.1psia	81.1F	82.1F	72.1psig
Sand Trap Inlet	Rec Cond Liq T	Br Ret Pump In T	Ret Pmp Diff P			
105.7psig	67.9F	132.7F	28.5psid			

N.A.-Channel Down; Value Not Available
1-Channel Down; Value Estimated From Field Notes.

MISCELLANEOUS

Sand Trap Vent	WF Venturi Press
53.9psig	320.8psig

Fig. 15-1. Test data for low flow case (Fig. 15).

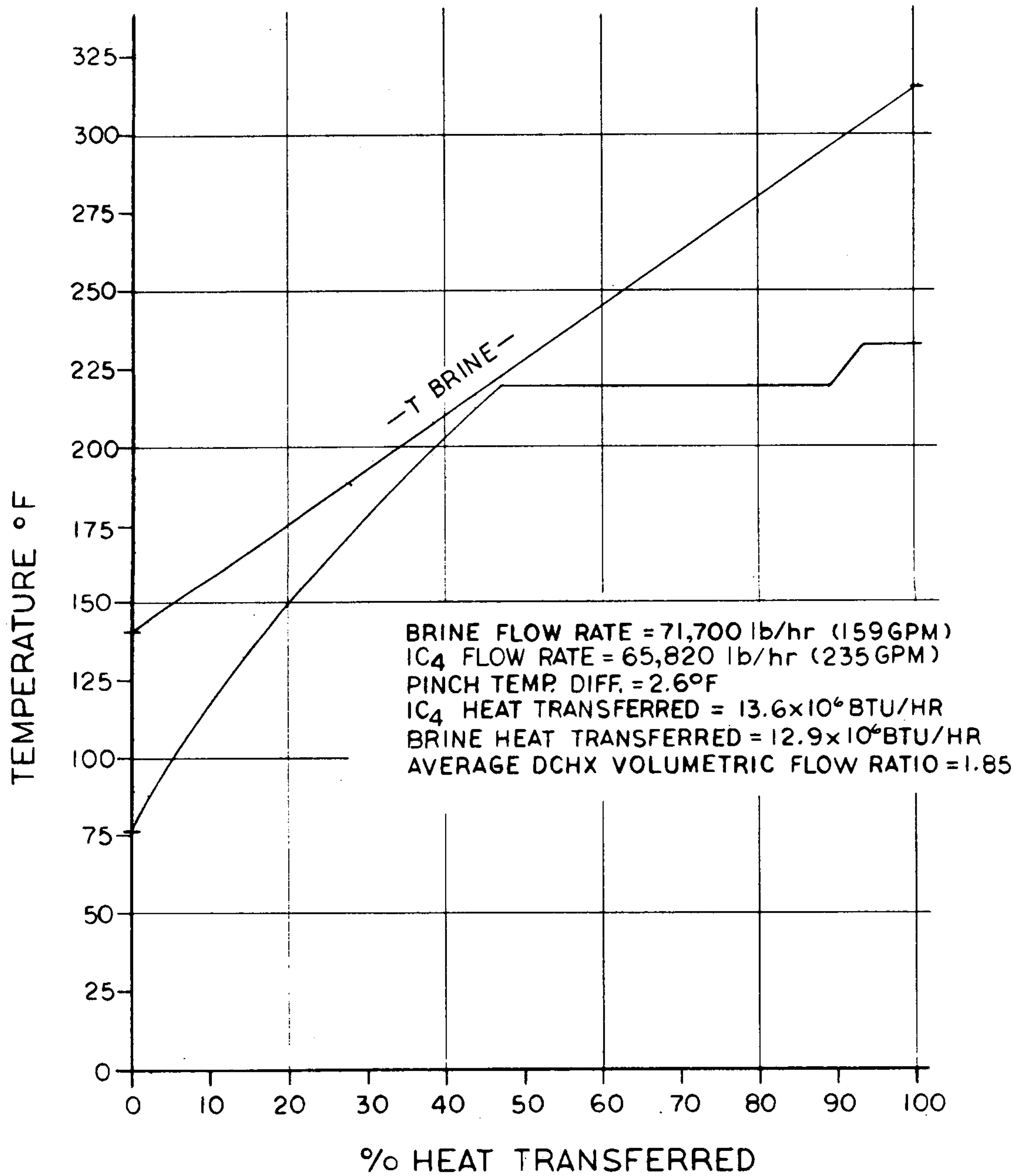

Fig. 16. Medium flow case DCHX heating curve. January 18, 1980, 12:47 p.m.

Baseline Test

18 Jan, 1980 12:47:00

Operator = RGO

BRINE DELIVERY / FLASH SYSTEM

Manifold Brine P	DH Pump Disch T	Brine Flash DF T	Brine Flash P	ST Brine Out T	Brine Pump DF P
294.6psig	319.7F	3.1F	86.0psig	317.0F	405.3psid

HEAT RECOVERY LOOP

CV DifferentialP	Sand Tr Vent T	Steam Vapor Flow	Steam Condense P	IC4 Liquid Flow	Bin HX IC4 Out T	IC4 Vapor Pressu
25.1psid	295.7F	N.A.	56.3psig	N.A.	239.3F	192.1psig
Calorimeter T						
79.8F						

DIRECT CONTACT LOOP

Brine Flow In	DCHX Brine In T	DCHX Brine Out T	IC4 Liquid Flow	IC4 Press In	DCHX IC4 In T	Column Pres Out
159.0gpm	313.6F	139.8F	235.1gpm	332.6psig	83.1F	315.7psig
Column Diff Pres	Column Temp 1	Column Temp 2	Column Temp 3	Column Temp 4	Column Temp 5	Column Temp 6
0.9psid	232.4F	232.8F	233.2F	230.2F	226.4F	232.2F
Column Temp 7	Column Temp 8	Column Temp 9	Column Temp 10	Column Temp 11	Column Temp 12	Column Temp 13
222.6F	221.4F	215.7F	213.7F	207.2F	164.3F	163.8F
Column Temp 14	Column Temp 15	Column Temp 16	Column Temp 17	DCHX WF out T	Utility Cooler T	Gen Phase 1
192.3F	158.0F	149.5F	142.6F	231.9F	65.3F	N.A.
Gen Phase 2	Gen Phase 3					
N.A.	N.A.					

TURBINE AND POWER OUTPUT

WF Orifice Diff	Turbine Inlet P	Turbine Inlet T	Turbine Exit P	Turbine Exit T	Generator Output	Phase 1 Voltage
271.0IN H2O	316.7psig	227.8F	45.0psig	140.0F [1]	N.A.	N.A.
Phase 2 Voltage	Phase 3 Voltage	Parasitic Power	Phase 1 Amps	Phase 2 Amps	Phase 3 Amps	Turbine Speed
N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

CONDENSER / HOTWELL

Condensate Temp	Hotwell Press	Hotwell Temp	IC4 Feed DF Pres
71.6F	42.6psig	76.1F	566.8psid

IC4 RECOVERY SYSTEM

Hydro Turb Dif P	Tailstock Press	Retn Pump In P	Comp In Press	Comp In Temp	Rec Comp Dsch T	Rec Condenser P
310.7psid	16.1psig	8.7psia	7.7psia	80.6F	94.3F	78.9psig
Sand Trap Inlet	Rec Cond Liq T	Br Ret Pump In T	Ret Pmp Diff P			
114.7psig	69.9F	137.7F	28.2psid			

N.A.-Channel Down; Value Not Available
1-Channel Down; Value Estimated From Field Notes.

MISCELLANEOUS

Sand Trap Vent	WF Venturi Press
61.4psig	322.6psig

Fig. 16-1. Test data for medium flow case (Fig. 16).

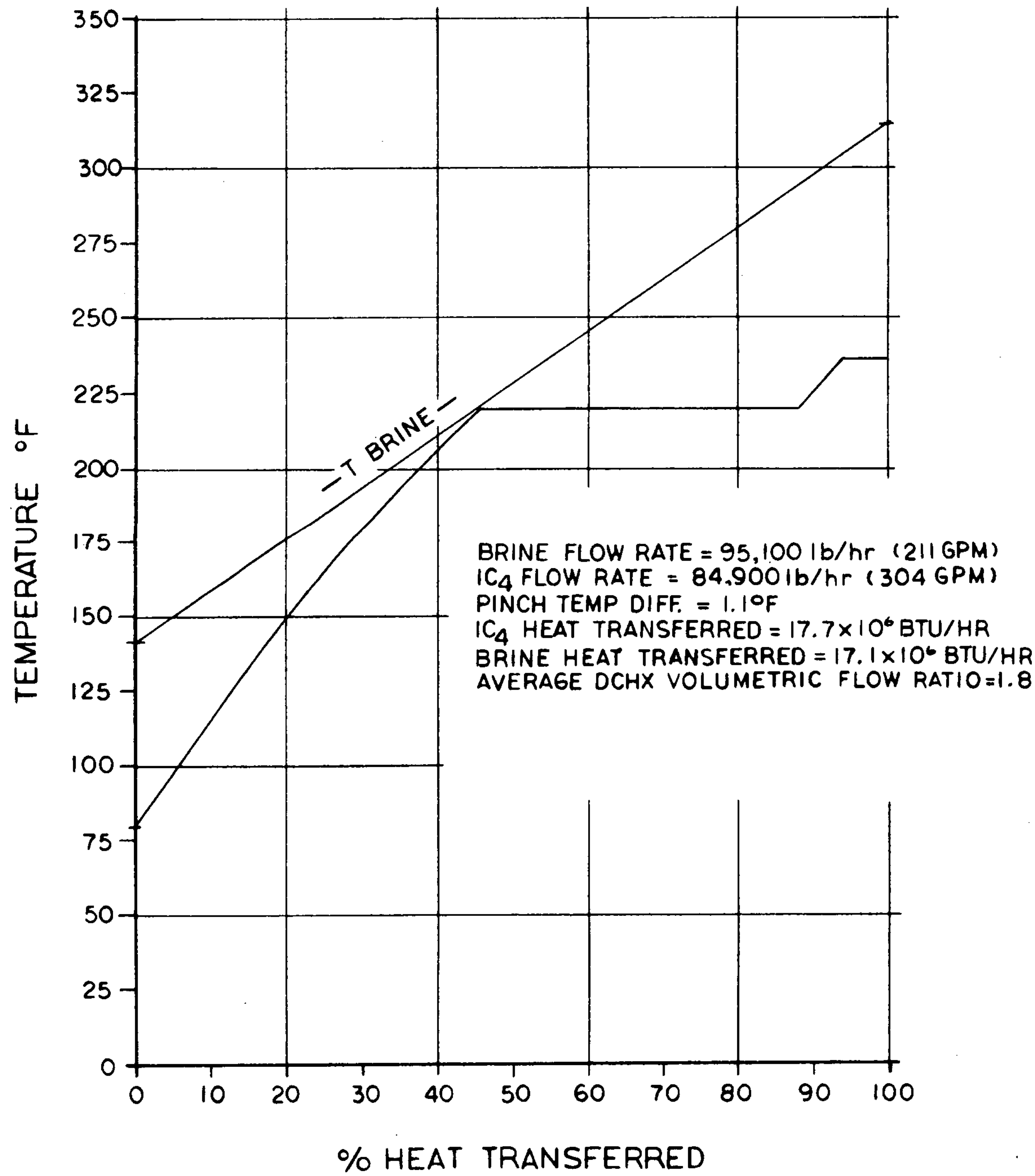

Fig. 17. High flow case DCHX heating curve. January 18, 1980, 4:29 p.m.

Baseline Test

18 Jan, 1980 16:29:00

Operator = RGO

BRINE DELIVERY / FLASH SYSTEM

Manifold Brine P	DH Pump Disch T	Brine Flash DF T	Brine Flash P	ST Brine Out T	Brine Pump DF P
288.7psig	319.5F	3.6F	86.2psig	317.4F	351.7psid

HEAT RECOVERY LOOP

CV DifferentialP	Sand Tr Vent T	Steam Vapor Flow	Steam Condense P	IC4 Liquid Flow	Bin HX IC4 Out T	IC4 Vapor Pressu
25.0psid	295.7F	N.A.	55.3psig	N.A.	162.2F	16.4psig
Calorimeter T						
76.9F						

DIRECT CONTACT LOOP

Brine Flow In	DCHX Brine In T	DCHX Brine Out T	IC4 Liquid Flow	IC4 Press In	DCHX IC4 In T	Column Pres Out
211.1gpm	314.5F[1]	140.9F	304.0gpm	338.7psig	84.7F	322.6psig
Column Diff Pres	Column Temp 1	Column Temp 2	Column Temp 3	Column Temp 4	Column Temp 5	Column Temp 6
1.4psid	237.9F	238.4F	239.2F	237.4F	237.5F	242.5F
Column Temp 7	Column Temp 8	Column Temp 9	Column Temp 10	Column Temp 11	Column Temp 12	Column Temp 13
224.1F	221.3F	217.9F	211.1F	207.7F	185.1F	183.4F
Column Temp 14	Column Temp 15	Column Temp 16	Column Temp 17	DCHX WF out T	Utility Cooler T	Gen Phase 1
202.3F	176.3F	156.1F	143.9F	236.7F	65.2F	N.A.
Gen Phase 2	Gen Phase 3					
N.A.	N.A.					

TURBINE AND POWER OUTPUT

WF Orifice Diff	Turbine Inlet P	Turbine Inlet T	Turbine Exit P	Turbine Exit T	Generator Output	Phase 1 Voltage
461.6IN H2O	311.9psig	232.2F	49.0psig	140.0F[1]	N.A.	N.A.
Phase 2 Voltage	Phase 3 Voltage	Parasitic Power	Phase 1 Amps	Phase 2 Amps	Phase 3 Amps	Turbine Speed
N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

CONDENSER / HOTWELL

Condensate Temp	Hotwell Press	Hotwell Temp	IC4 Feed DF Pres
73.4F	46.9psig	79.0F	538.3psid

IC4 RECOVERY SYSTEM

Hydro Turb Dif P	Tailstock Press	Retn Pump In P	Comp In Press	Comp In Temp	Rec Comp Dsch T	Rec Condenser P
316.2psid	16.3psig	6.5psia	5.6psia	83.8F	96.7F	77.2psig
Sand Trap Inlet	Rec Cond Liq T	Br Ret Pump In T	Ret Pmp Diff P			
127.9psig	62.3F	138.2F	27.7psid			

N.A.-Channel Down; Value Not Available
1-Channel Down; Value Estimated From Field Notes.

MISCELLANEOUS

Sand Trap Vent	WF Venturi Press
60.9psig	331.8psig

Fig. 17-1. Test data for high flow case (Fig. 17).

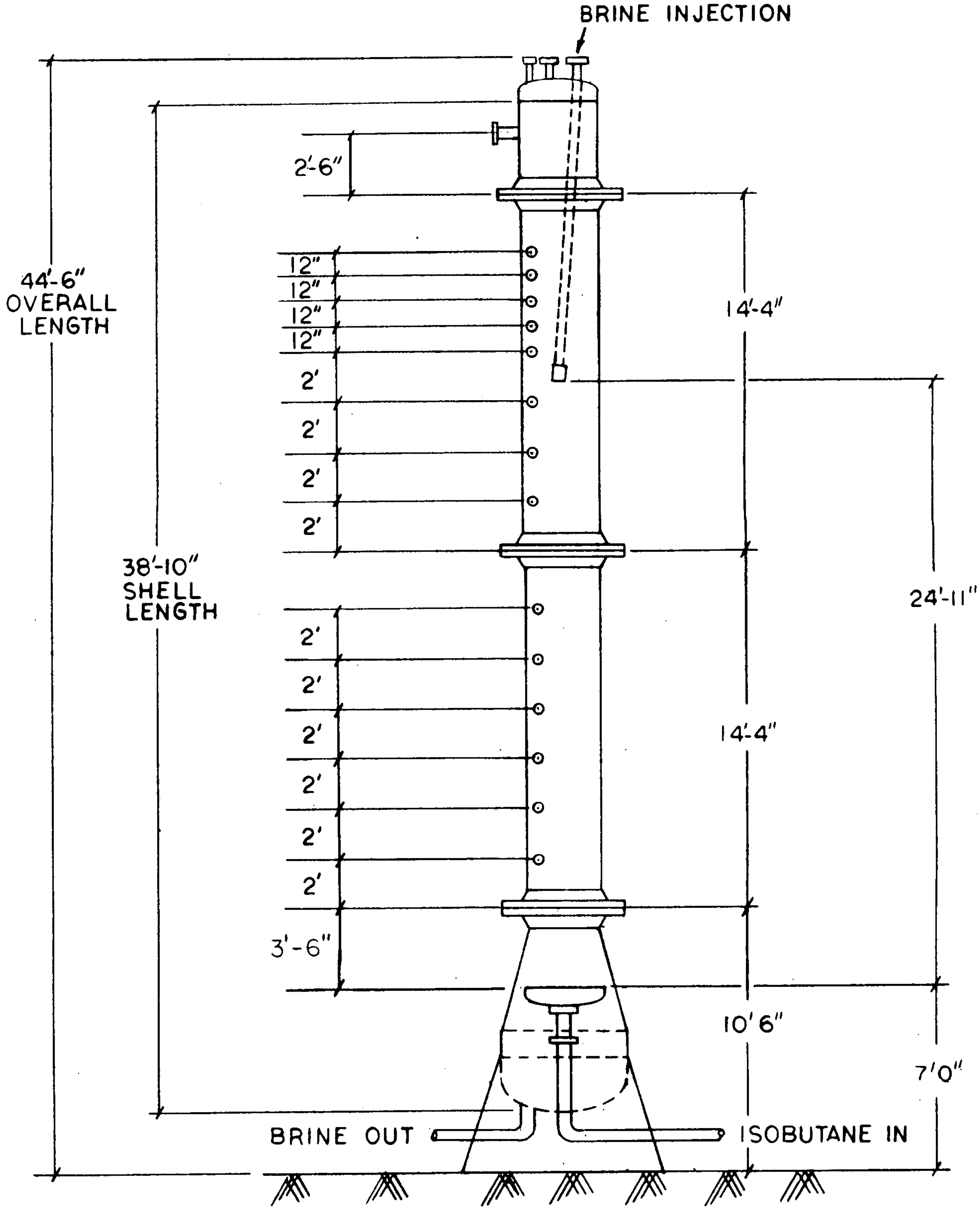

Fig. 18. Direct contact heat exchanger temperature probe locations.

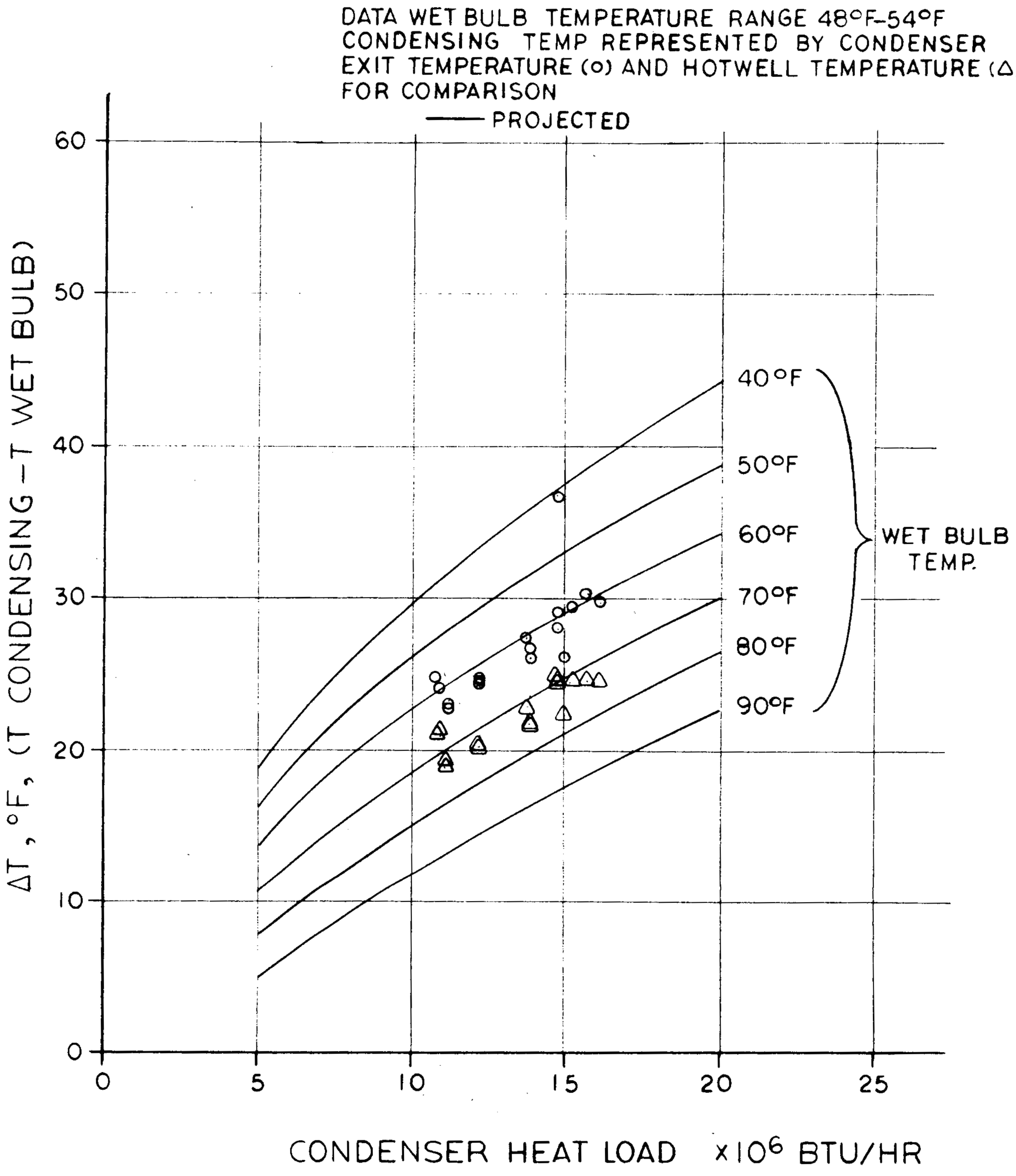

Fig. 19. Predicted and actual condenser heat transfer performance.

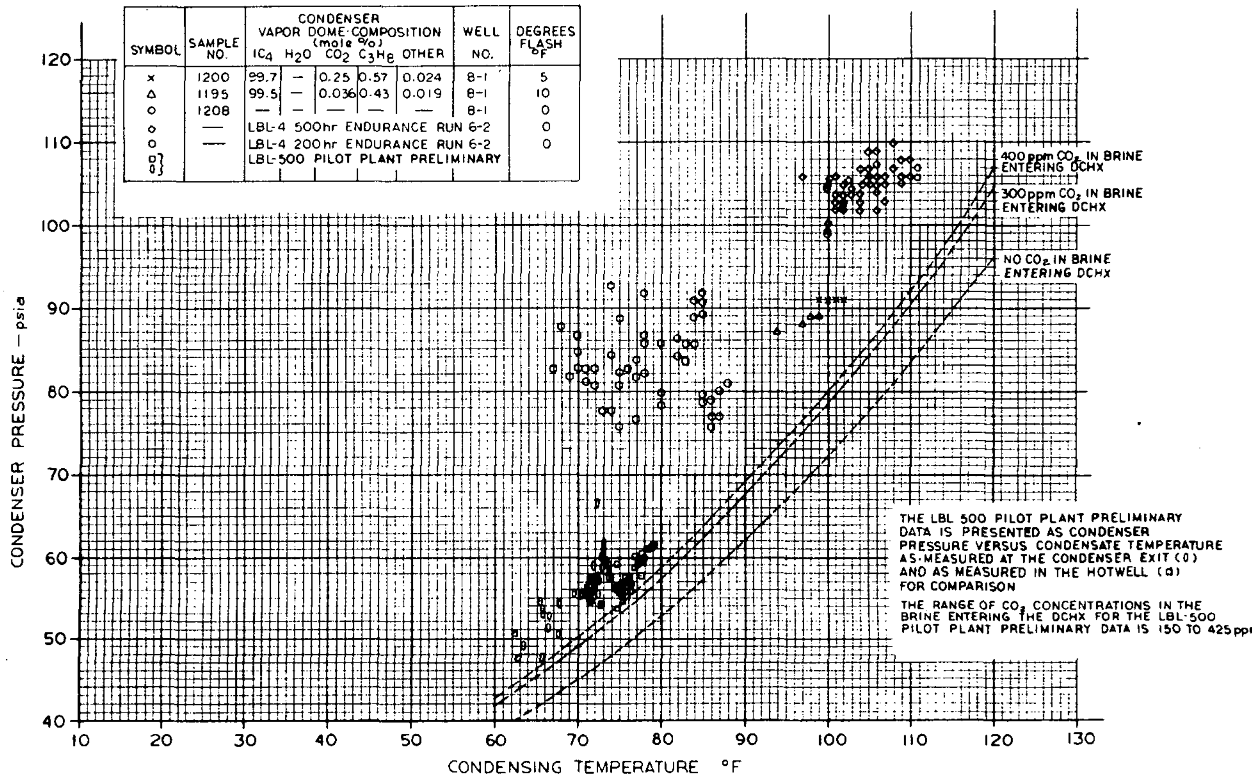

Fig. 20. Comparison of field data with theoretically determined condenser pressure as a function of temperature.

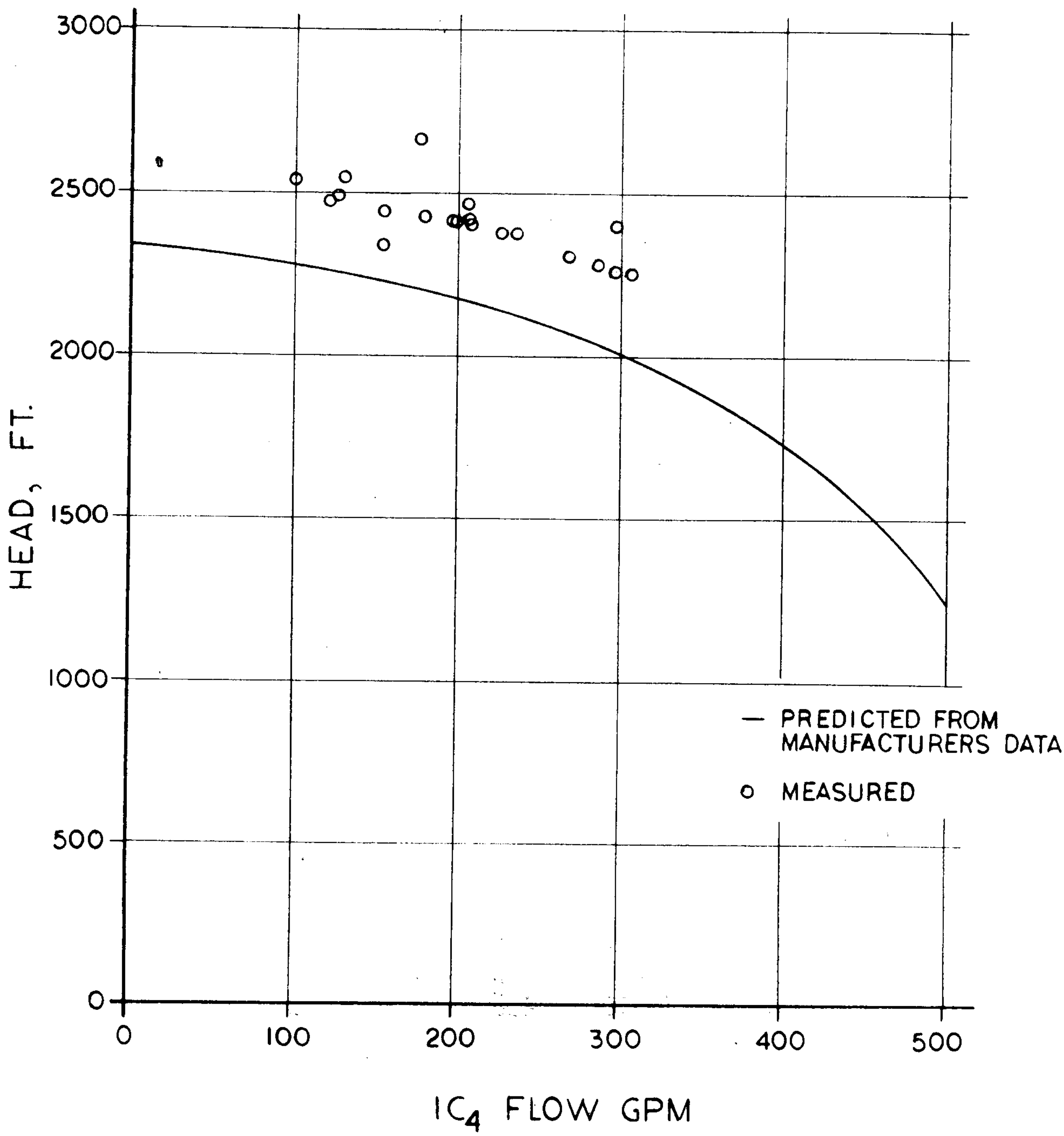

Fig. 21. Comparison of measured and predicted performance of IC_4 feed pump.

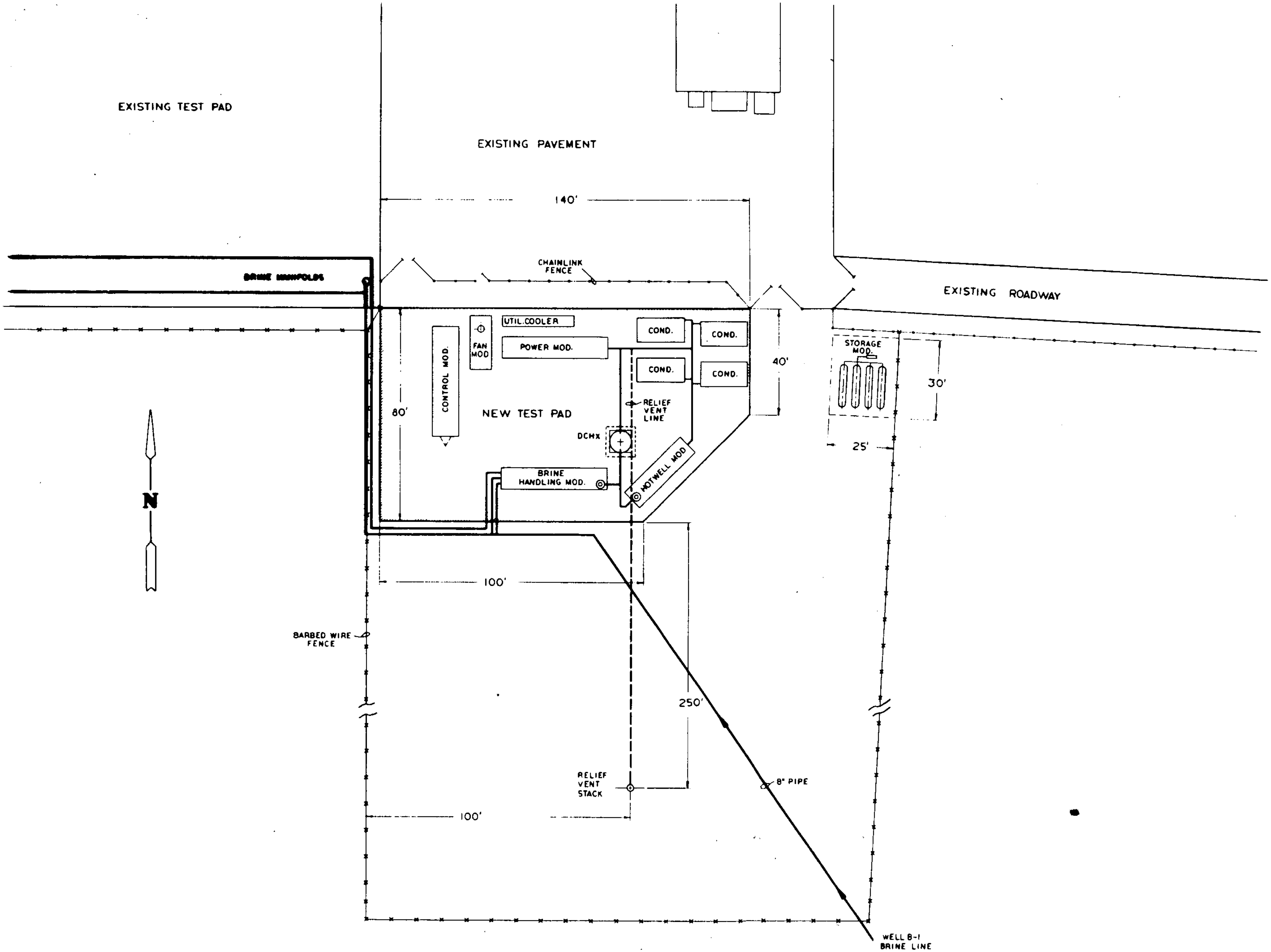

Fig. 22. General site layout of 500 kW pilot test plant at DOE's East Mesa Geothermal Component Test Facility.

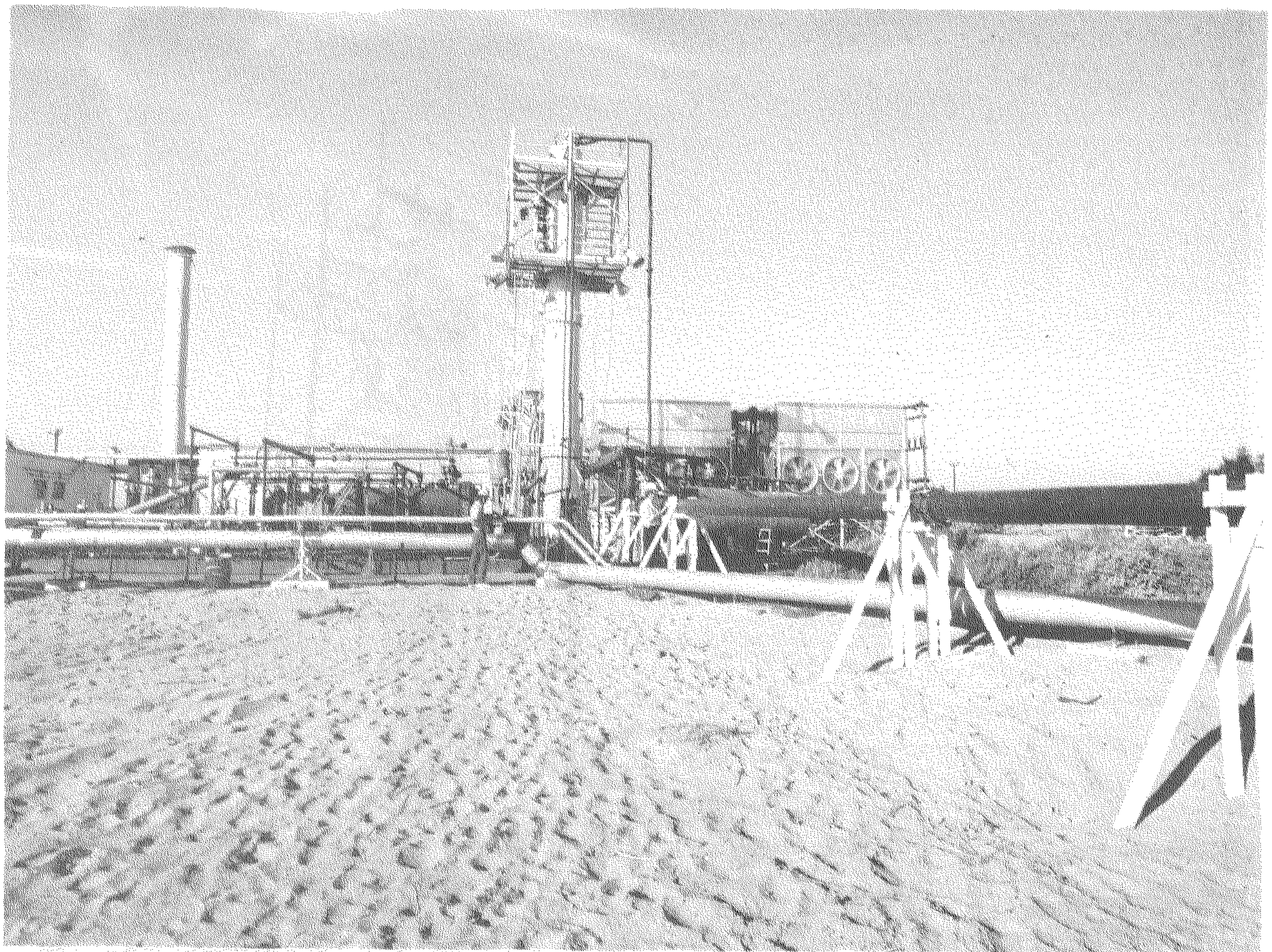

Fig. 23. 500 kW direct contact pilot plant.

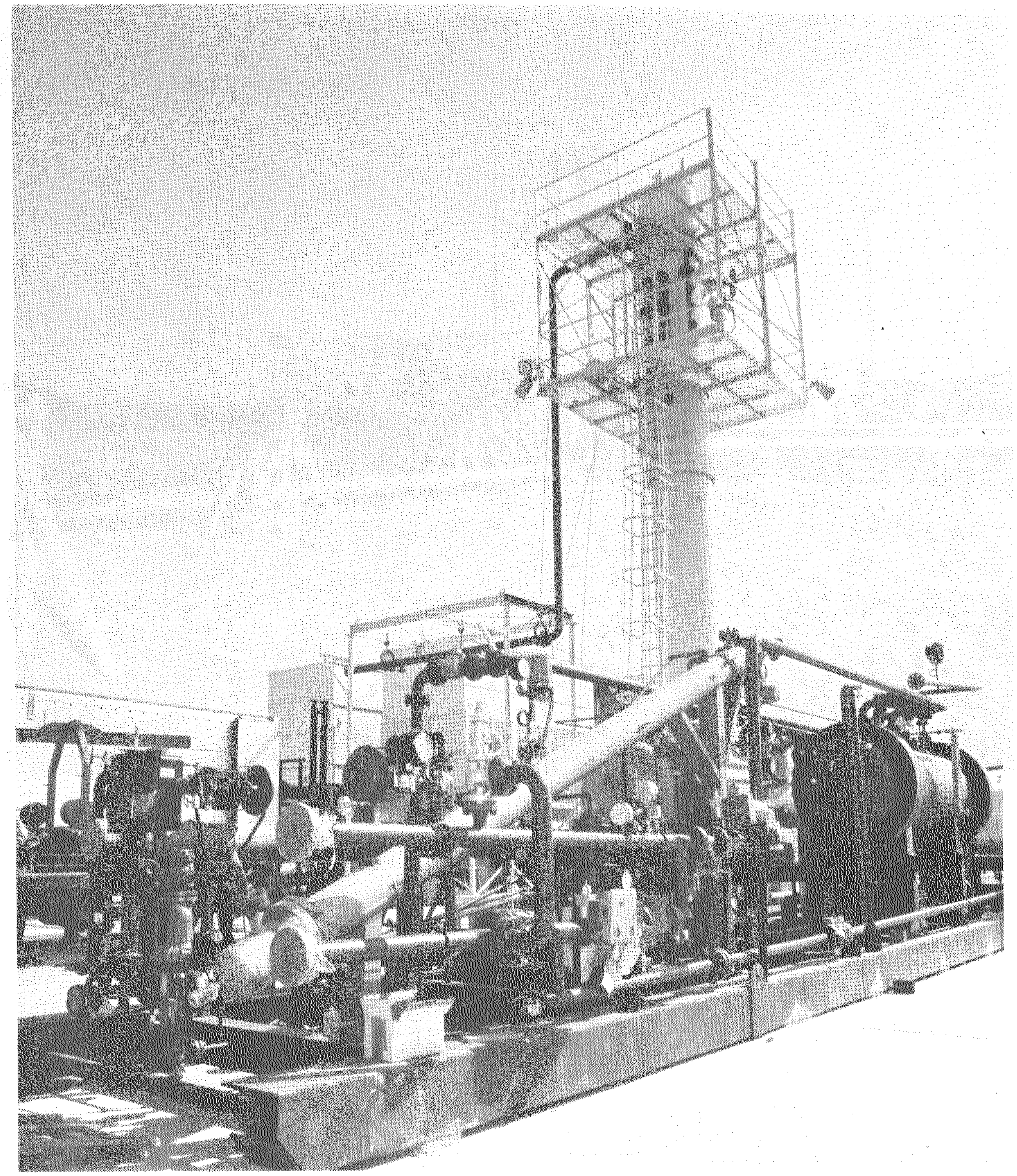

Fig. 24. Brine module (foreground) and direct contact heat exchanger.

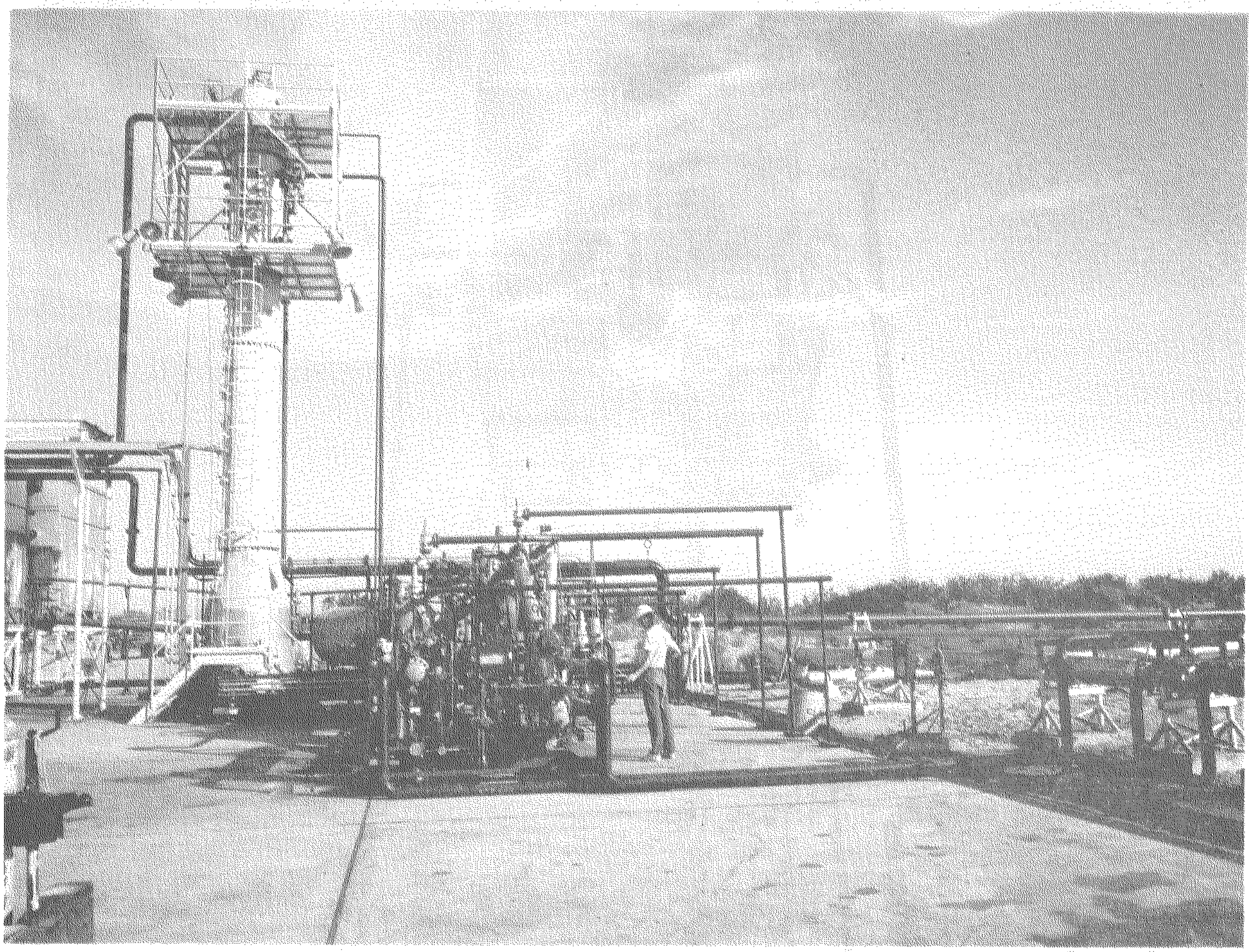

Fig. 25. Brine module and DCHX.

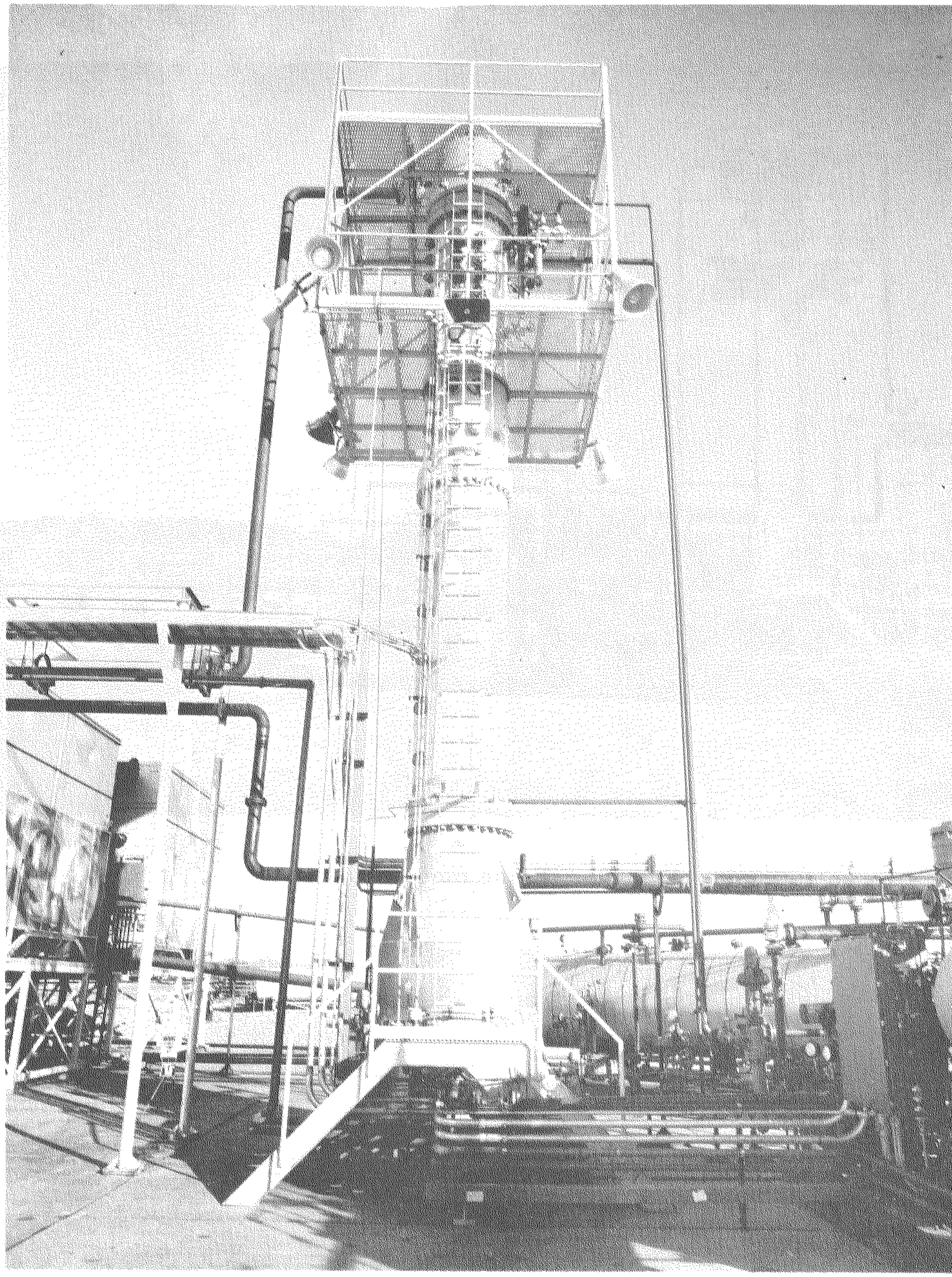

Fig. 26. Direct contract heat exchanger.

Fig. 27. Power turbine and turbine bypass control valve.

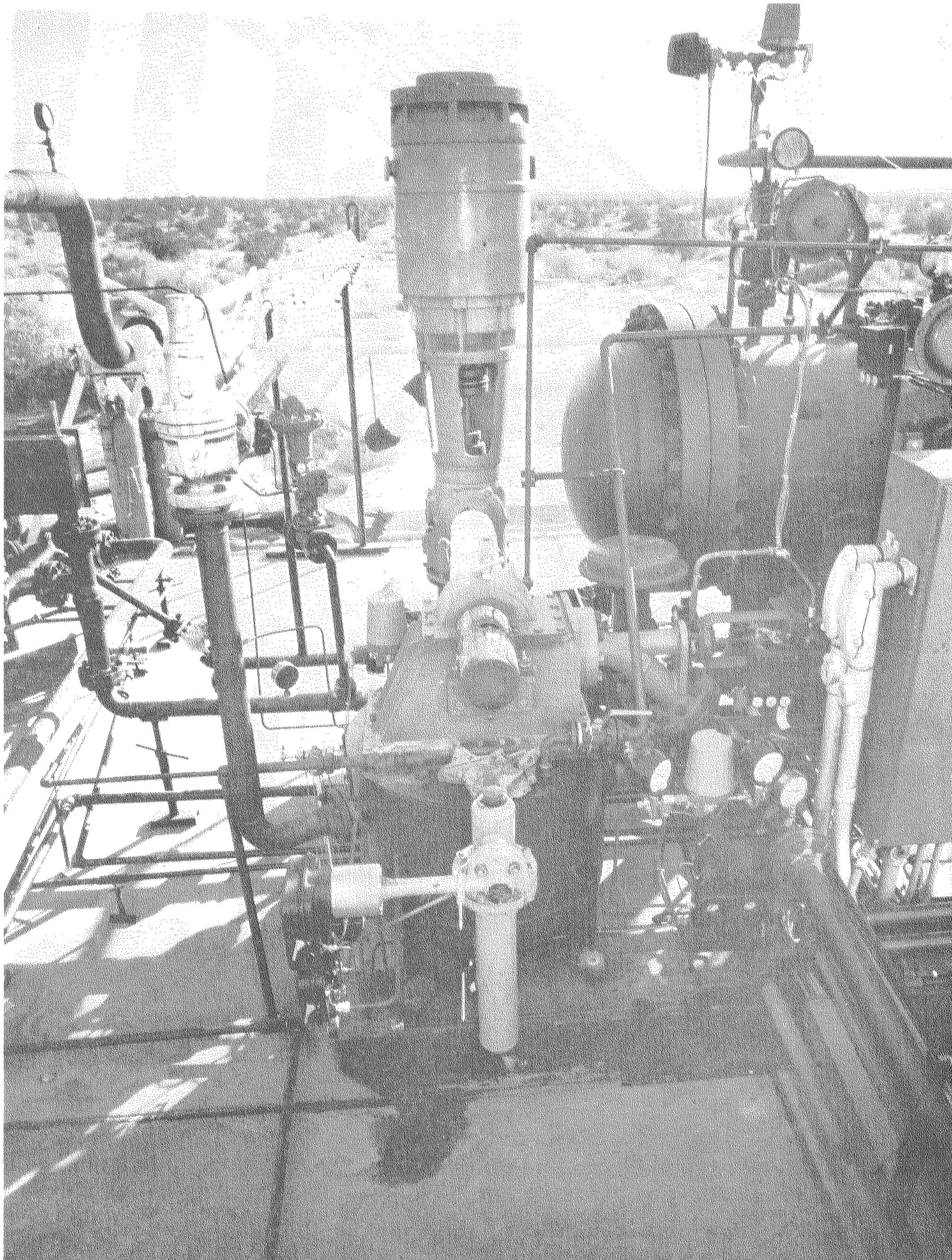

Fig. 28. Hydraulic turbine, tailstock, and brine boost pump.

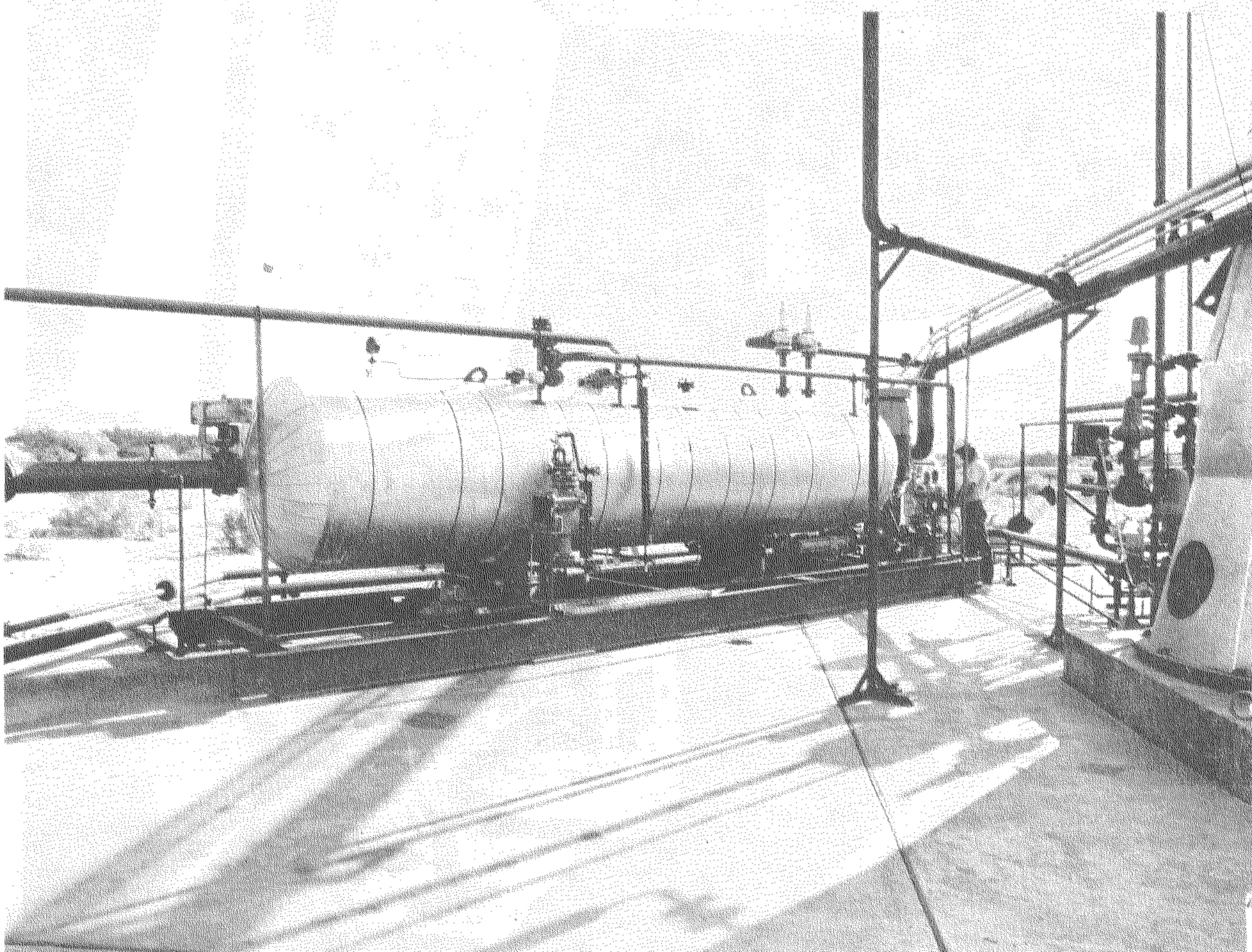

Fig. 29. Hotwell module.

Fig. 30. 500 kW pilot plant control console.

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