# HEBER BINARY PROJECT

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## ABSTRACT

The need to demonstrate commercial scale, binary cycle, geothermal technology was first expressed in the mid-1970's in EPRI Report ER-1099. From those initial conceptual plans, the Heber Binary Project has finally evolved into an operating plant. Engineering was kicked off in early 1981, with construction beginning in June 1983. Start-up commenced in early 1985 culminating in the synchronization of the generator in June 1985. Half of the brine facilities are in operation with the second half scheduled for completion in mid 1987. Initial component data is being gathered, and, as the second phase of brine field development comes on stream, the plant will begin full load testing. The plant's demonstration period will continue into 1988 after which it is planned to go into commercial operation.

## INTRODUCTION

Formally begun in September 1980 with the signing of a Cooperative Agreement between San Diego Gas & Electric (SDG&E) and the U. S. Department of Energy (DOE), the Heber Binary Project seeks to prove the economic and operational viability of binary cycle geothermal technology in large scale geothermal power production. Also counted among the Project's sponsors are the Electric Power Research Institute, the State of California, Imperial Irrigation District, the Department of Water Resources, Southern California Edison, Pacific Gas and Electric, Fluor Engineers, Inc., and Magma Energy, Inc. By providing a proven alternative to the flash process on low- to moderate-temperature (below 400°F) geothermal resources, the Project hopes to expand the worldwide development of geothermal energy into these lower-temperature resources.

## PROCESS DESCRIPTION

The process used by the plant is a supercritical Rankine cycle with a 90/10 mixture of isobutane and isopentane as the binary working fluid. Geothermal brine provides the heat source to vaporize the working fluid, and a wet cooling tower provides the heat sink to condense the exhaust from the turbine.

The geothermal brine is produced from pumped wells at an adjacent facility owned by the Project's heat supplier. Once the heat is removed, the brine is returned to the heat supplier for reinjection at his facility located about one and a half miles from the plant. The pressure for reinjection is provided by the plant's brine return pumps.

The hydrocarbon which is contained within a closed loop is elevated to supercritical pressure by two sets of pumps operating in series. The hydrocarbon is vaporized in the heat exchangers and flows through a knockout drum prior to the turbine to remove any entrained liquids. The hydrocarbon vapor expands through the turbine to drive the generator and finally exhausts to the condensers to complete the cycle.

The plant operates with a floating cooling cycle. Cooling water temperature, which determines condenser pressure, is allowed to fluctuate with ambient wet bulb temperature. As a result, generator output will vary with ambient conditions for a given set of turbine throttle conditions. Figure 1 shows the schematic of the plant with the major process stream conditions for rated plant output at 55°F wet bulb temperature.

## PLANT DESIGN

Using the schematics in the early EPRI reports as a starting point, the requirements for operability, maintainability, reliability, and safety were incorporated into the plant in arriving at the final design. With the basic criteria of design a 45 MW plant with a 30 year life, Fluor Engineers, Inc. had engineering and procurement responsibility on the Project. Additionally, the first of a kind nature of the plant placed emphasis on simplicity in the design as well as balancing capital cost with overall efficiency.

The brine heat exchangers, as the largest single capital cost component, were the subject of detailed optimization studies. An arrangement of two heat exchanger trains with four shells per train was selected as the optimum way of packaging the required surface area. A study of the brine pumping requirements selected a variable speed drive using a hydraulic coupling for the brine return pumps to meet their needed range of flows and pressures. The four return pumps are sized for the flow requirements of an estimated 30 year end-of-run reservoir temperature of 338°F, but at initial 360°F brine temperatures, only three pumps will be required. The materials in the brine system are primarily carbon steel with corrosion allowances based on a 12 mpy corrosion rate. Notable exceptions are the Allegheny Ludlum 29-4c heat exchanger tubes and Alloy 20 brine return pump casings.

In the hydrocarbon system, the condensate and booster pumps are individually paired in a series arrangement to simplify piping and pump protection. Since a downward turbine exhaust was not required for the hydrocarbon, a side exit from the turbine was used with the turbine set essentially at grade level. The condensers are on elevated foundations to allow room for the hydrocarbon reservoirs directly below. Dual stop and control valves are located at the turbine inlet with a separate smaller valve used for synchronization and low flow operations. Other features of the hydrocarbon system are a coalescing filter to remove water and foreign matter from the hydrocarbon, and a loop seal between each condenser inlet and hydrocarbon reservoir to serve as a system exhaust point for the hydrocarbon during start-up and venting situations.

A standard wet cooling tower serves as the heat sink in the cooling water system. Two large settling ponds, gravity fed from the nearby irrigation canal, serve to allow silt and other solids to settle out before entering the system. Fiberglass reinforced plastic pipe is used for most of the cooling water system piping, and Trent Tube's SeaCure is the condenser tube material.

A digital, microprocessor-based control system was selected to control the process rather than a conventional analog system to provide greater flexibility, reduced control room size, and increased data acquisition capability. The system includes the distributed control system, which controls the plant, the programmable controller system, which performs the digital logic for the start/stop of all major pumps, and the data acquisition system, which provides all plant logging and data acquisition. On a commanded load change, the control system begins actuation of the turbine control throttle valves to adjust hydrocarbon vapor flow for the selected power output. Additionally, the hydrocarbon liquid flow valves are actuated to balance hydrocarbon liquid and vapor mass flows, and the brine return pump speed is adjusted to maintain brine flow at a fixed rate to hydrocarbon flow. Turbine inlet temperature is also used to bias the brine flow control signal.

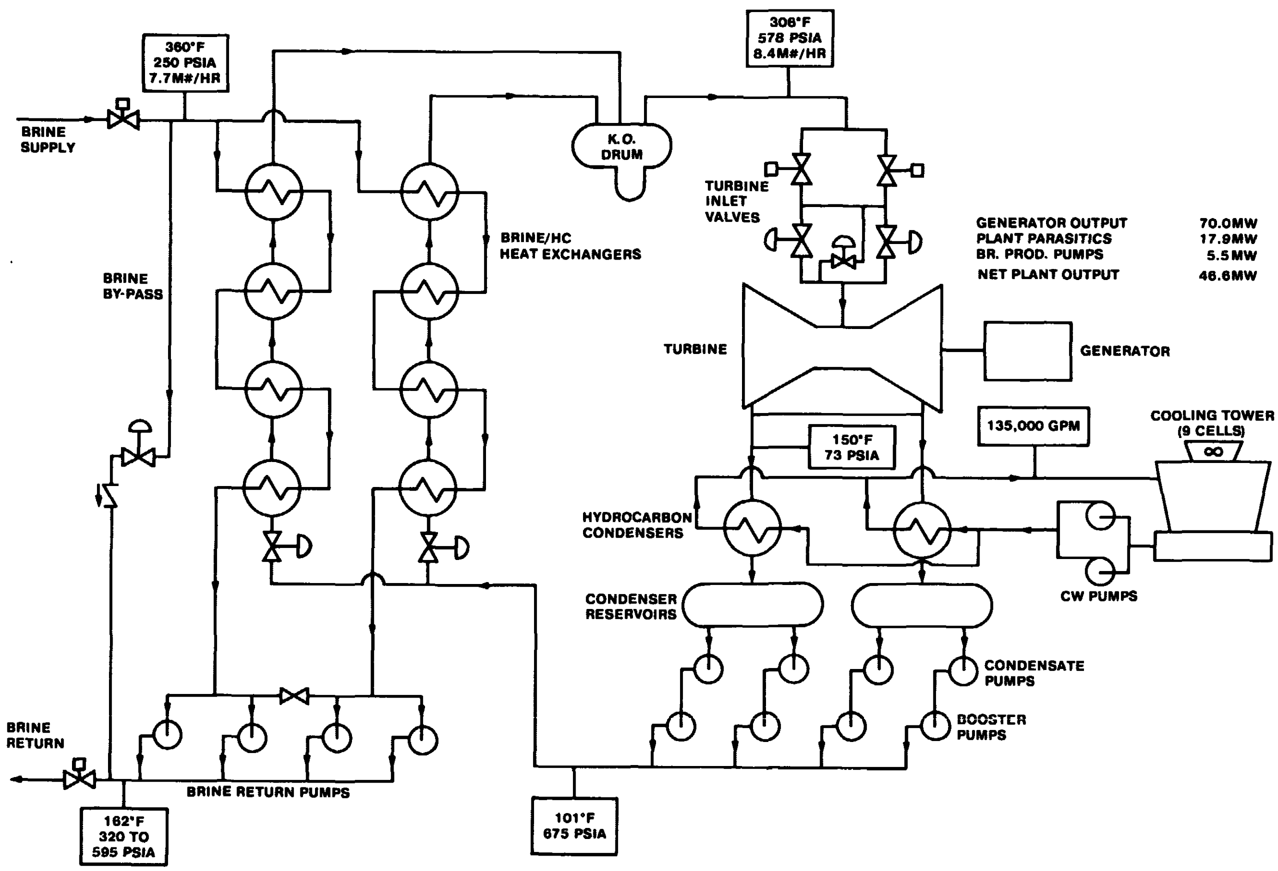


Figure 1 - Plant Diagram with Full Load Stream Conditions of 55°F WBT

An override to the control system is also provided to prevent operation of the turbine in the two-phase region. Turbine control valve actuation can be inhibited based on turbine inlet pressure and temperature until sufficient turbine inlet margin is achieved to support higher loads.

After the major process systems, the plant fire protection system is the most extensive. Underground fire mains feed a water spray system with fire water pressure provided by fire pumps which take suction from the settling ponds. Cross-zoned ultraviolet (UV) detectors and combustible gas detectors comprise the hazard detection system which can actuate the water spray. Other major auxiliary systems include the hydrocarbon unloading and recovery system, the flare system, the inert gas system, and the service water system.

All the plant equipment was competitively bid and purchased under the requirements of the federal procurement regulations. Table 1 lists the costs and design specifications for the major plant components.

TABLE 1

| | |
|---|---|
| Turbine-Generator | $5.7M |
| Four stage, double axial flow, 3,600 RPM turbine; 86.6% efficiency at guarantee point; 3 phase, 60 Hz, 13.8 KV, 77.8 MVA, hydrogen cooled generator | |
| Heat Exchangers | $7.2M |
| Two pass, counterflow, 1,584 MBTU/hr, 38,200 $ft^2$/shell, 850 psi shell/tube side design pressure, .75 in. OD, 20 BWG AL 29-4c tubes | |
| Condensers | $4.9M |
| Two pass, cross flow, 1,342 MBTU/hr, 203,260 $ft^2$/shell, .75 in. OD, 20 BWG SeaCure tubes | |
| Brine Return Pumps | $1.5M |
| Single stage, horizontal split, 6,000 gpm, 1,200 ft. head, variable-speed hydraulic coupling, 2,500-hp motor | |
| Hydrocarbon Condensate Pumps | $.5M |
| Three stage, vertical can, 8,670 gpm, 571 ft. head, 900-hp motor | |
| Hydrocarbon Booster Pumps | $1.3M |
| Two stage, horizontal split, 8,670 gpm, 2,109 ft. head, 3,500-hp motor | |
| Cooling Water Pumps | $.8M |
| Single stage, vertical, 70,000 gpm, 100 ft. head, 2,250-hp synchronous motor | |
| Cooling Tower | $2.7M |
| Nine cell, induced draft, counterflow | |

## HEAT SUPPLIER

The facilities which supply the geothermal fluid to the plant are owned by Chevron Geothermal Company and Unocal, the two leaseholders in the Heber KGRA. Directionally drilled production wells using shaft-driven, downhole pumps set between 700 and 1000 feet produce the brine. A second facility located one and one-half miles from the plant on the periphery of the reservoir serves to reinject the brine. Development of the reservoir for the plant is planned in two phases. Seven production and five injection wells were drilled in 1984 to supply 50% brine flow to the plant. The drilling of the remaining six production and four injection wells is planned in the later half of 1986 with full brine production capability scheduled for the second quarter 1987. In the first phase of the reservoir development, the heat supplier is paid on a BTU basis for the energy consumed by the plant, and in the second phase, a demand charge based on guaranteed brine flow is included in the charge for heat. Since both brine production and injection pumps are a plant auxiliary, a factor in the pricing formulas removes from the heat bill the cost of heat associated with generating power for the brine pumps.

The design flow rate for the production wells varies with the completion depth, but on the average is about 1500 gpm per well. The early experience has been that while some wells are performing at design levels, the overall average has been less than design. On initial start-up of the field, the wells produced at close to the design rate. As well interference stablized, the average production rate declined some 15 to 20 percent. The initial setting depth of most pumps was lowered to provide more operational flexibility. Consequently, some wells are limited by pump capacity. A program of well workovers has also been instituted by the heat supplier to improve the productivity of the below average wells.

Downhole pump life for has been below expectations. Inspection of the failed pumps revealed failure of the bowl bearings. The carbide hard facing on the pump shaft has also failed contributing to the bearing failure. Several design and material changes were incorporated in the repairs, and operating results on the repaired pumps has been favorable thus far.

## CONSTRUCTION

The construction of the plant was organized into four major construction packages. All packages were competitively bid, fixed price contracts overseen by a construction manager, Dravo Constructors, Inc. Construction began in June 1983 with the Site Development package. Two months later, the Civil/Structural contract which included all foundations, pipe supports, and underground piping was awarded. The Mechanical and the Electrical contracts were awarded in April and June of 1984, and encompassed the bulk of plant construction. An additional contract was awarded to a specialty heavy lift contractor in early 1984 to move large equipment from the local railhead to the site.

The construction effort spanned the heat of two summers in the Imperial Valley where temperatures of 110°F were common. Construction start times were moved up to 5:30 a.m. to take advantage of the cooler part of the day, and an evening welding shift was also utilized during the mechanical work. In addition to the craft labor productivity penalty, the heat affected concrete pours requiring as much as 1200 pounds of ice be added to each load to keep the concrete below specified maximum temperatures. The majority of difficulties during construction came in the early phase. During earthwork operations, suitable fill material for roads and building foundations could not be found within the plant boundary as predicted by the site geotechnical report. It had to be borrowed from the laydown area and transported to the needed locations. The biggest impact to construction came in a design change which shifted electrical and I&C distribution from overhead to underground. The resulting underground ductbanks had a major impact on equipment foundations and underground piping. The mangement of a large number of subcontractors by the prime contractor and poor quality control on concrete placements also hampered the early phase of construction.

START-UP

Plant start-up officially began in October 1984 with the energization of the plant switchyard and culminated with turbine roll in May and initial synchronization in June 1985. Start-up was the responsibility of SDG&E and progressed on a system by system basis. As systems were completed by the construction forces, each process transmitter and control loop was checked out wire by wire and then calibrated. In addition, control valves were stroked and motors bumped before the actual operational check out of the system was performed.

The smaller auxiliary systems were the first to go through the start-up process which concluded with the brine and hydrocarbon systems. The hydrocarbon system start-up was unexpectedly impacted because of delays in hydrocarbon shipments coupled with the inability of the hydrocarbon supplier to meet specification requirements. In the brine system, the return pumps were initially operated with water from the cooling tower. Then, prior to filling the system with brine, this water was drained to prevent any precipitation from the mixing of the tower water with the brine. The plant was heated up by first establishing liquid hydrocarbon flow through a bypass from the heat exchanger exit back to the condensers. Cold brine was circulated within the plant using the brine return pumps, with hot brine gradually fed into the circulating brine to warm up the plant. A 50°F per hour warm-up rate was used to prevent thermal shock to the heat exchangers. As hydrocarbon temperatures reached throttle conditions, the flow was switched to the turbine bypass line to allow warm-up of the knockout drum and turbine inlet piping. The initial attempts of this bypass line switchover caused the knockout drum to fill with liquid. Raising the temperatures of the hydrocarbon vapor prior to the switch solved this problem. Once sufficiently superheated hydrocarbon vapor was being generated, the synchronizing valve was opened admitting vapor to the turbine. With the turbine at its normal operating speed, excitation voltage was applied to the generator and the generator breaker was closed putting the plant on line.

OPERATIONS AND DEMONSTRATION

The operation and maintenance function at the plant has been contracted to WESTEC Services, Inc., who is overseen by an on-site SDG&E plant staff. Formal classroom operator training began in July 1984, and this was later supplemented with on-the-job training as construction and start-up progressed. The plant is manned twenty-four hours a day by a four-man rotating shift consisting of a shift supervisor, control operator, assistant control operator, and maintenance helper. The maintenance staff is on-site during the normal work day and includes four instrument technicians to meet the instrument calibration requirements of the demonstration.

The first six months of plant operation was hampered primarily with turbine related problems. During a planned shutdown following a brief initial run, an inspection of the turbine inlet strainer revealed that it had parted from its flange ring and had lodged in the turbine inlet. The valve seats on all four turbine inlet valves were also discovered to have been damaged. The turbine rotor was removed and returned to the shop for rebalancing and cosmetic refurbishment of the turbine's blades. While damage to the rotor was surprisingly minor, the plant remained off line for two months. It returned to service in September and was hampered by several problems which had not surfaced during start-up. A failure of the turbine main lube oil pump was the largest of these, holding the plant out for all of November. After returning to service on December 8, 1985, following its dedication ceremony, the plant remained on line over 92% of the time for the next five months.

In addition to its equipment problems in late 1985, the brine supply never reached its expected flow rate of 3,750,000 lb/hr. Production well workovers improved flows somewhat with the reservoir able to sustain flows of about 2,700,000 lb/hr. At these flows, gross output is about 16.5 MW with net output equal to 5 MW. Working with the heat supplier, the plant went into an operating mode to maximize brine flow. Brine flow is set by drawing down supply pressure to the plant to the low limit of 190 psig. Hydrocarbon flow is then adjusted to achieve a minimum brine return temperature of 150°F. At these flows, the heat exchangers and condensers are operating at about 75% of design duty. The result is throttle conditions are typically about 12°F hotter into the turbine and condenser pressure is about 13 psi lower than design conditions.

Plant testing has concentrated on individual components, comparing factory data with installed test results. In this phase of testing, none of the pumps tested has failed to meet its factory performance data. During periods of maximized brine flow, plant testing shifted to the cooling system and condensers, determining the impact floating cooling on plant output. At these loads, with brine and hydrocarbon flows remaining constant a 20°F rise in cooling tower basin temperature will decrease generator output by about 3 MW. In conjunction with plant testing, the corrosion monitoring program has been investigating corrosion rates on actual and potential future plant materials. Carbon steel corrosion rates in the brine have been averaging between 2 to 3 mpy with rates 2 to 4 mpy higher during the two month shutdown. The high alloy steels, including AL 29-4c and SeaCure, have shown no weight loss.

In addition to the operational data, one of the chief goals of the Project is to provide data on the economic viability of future binary plants. With the costs of this first plant as a starting point and using information gained during demonstration, the Project plans to produce estimates of costs for follow-on plants. The capital costs for this plant are measured by those incurred through initial generator synchronization, and are contained in Table 2.

TABLE 2

| | (M$) |
|---|---|
| Engineering | 19.5 |
| Equipment | 47.6 |
| Construction[1] | 31.6 |
| SDG&E & Others[2] | 12.7 |
| O&M | 2.8 |
| | 113.7 |

1 Includes construction management

2 Includes licensing, start-up, project management, and outside consultants.

For a second plant, it is expected that considerable savings would be realized in the "Engineering" and "SDG&E & Others" categories, since first time engineering costs would not be incurred, and the project management staff required on this type of project would also not be necessary. As more operating data becomes available potential savings in "Equipment" and "Construction" might be available.