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WASTE-HEAT DISPOSAL FROM U.S. GEOTHERMAL POWER PLANTS — AN UPDATE*

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Summary

Dissipation of the heat rejected from geothermal power plants is a major concern because the inherently low efficiencies result in heat rejection rates that are three to four times greater per kilowatt of installed capacity than is typical of fossil- or nuclear-fueled stations. The most cost-effective methods of waste heat dissipation involve the evaporation of water, yet most of the important hydrothermal resources of the U.S. are located in areas where cooling tower makeup water for power plants is in short supply. Flashed-steam power cycles can use condensate derived from the geofluid for tower makeup unless reinjection is necessary, as is already required at some sites. Condensate is not available from binary cycles because the geofluid is reinjected. Geothermal station makeup water requirements have been estimated at 50 to 100 m^3/yr per kilowatt of electrical capacity.

Some of the more interesting and significant methods that are currently being studied in the U.S. for reducing waste heat dissipation system costs and water consumption are (1) allowing plant power output to vary with ambient conditions, (2) use of ammonia to transport waste heat from the turbine condenser to air-cooled coils, (3) development of a plastic-membrane type wet/dry tower, (4) marketing of steam turbines that can tolerate a wider range of back pressures, (5) use of circulating water storage to delay heat dissipation until more favorable ambient conditions exist, (6) development of tubes with enhanced heat transfer surfaces to reduce condenser capital costs, and (7) use of evaporative condensers to reduce costs in binary cycles. Many of these projects involve large-scale tests that are now fully installed and producing some preliminary data. Definitive results from some of the tests may not be available until mid-1982 or later.

1. INTRODUCTION

Disposal of the heat rejected from geothermal power plants is a major problem because the low thermal efficiencies (10-15%) caused by the relatively low-temperature heat sources result in heat rejection rates that are three to four times greater per kilowatt of capacity than is typical of fossil- or nuclear-fueled stations. The most economical methods of heat dissipation involve the evaporation of water, but the major hydrothermal reserves in the U.S. are almost all located in regions

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where water for cooling tower makeup is scarce. Geothermal plants using the flashed-steam cycle produce enough condensate for tower makeup, if reinjection is not required. Reinjection is already mandated in some resource areas, however, and since the subterranean effects of geofluid withdrawal are not well known at many others, it seems likely that reinjection regulations will become more stringent. A source of water is needed for binary-cycle plants because, in this case, the geothermal fluid is reinjected.

The conditions of water availability, cost, and quality at potential sites are so diverse that it is difficult to generalize. In 1980 Robertson et al. (Ref. 1) estimated geothermal power plant cooling tower requirements to be between 50 and 100 m^3/yr per kilowatt of net electrical capacity (Fig. 1). Differences in climate may affect the amount by up to 20%, and binary cycles may require up to 15 to 20% more water than flashed-steam systems. The ORNL study (Ref. 1) also roughly estimated the amount of makeup water needed to develop the full potential of the known hydrothermal reserves in the western states of the U.S., made a broad survey of the amounts of water present in the resource areas, and reviewed the legal aspects of making the water available for consumptive use by the stations. The study concluded that the difficulty of obtaining cooling tower makeup water may be one of the most serious obstacles to the development of economical geothermal power from the western hydrothermal reserves.

Many observers believe that new thermal power stations in some regions of the U.S. will have to rely on dry and wet/dry methods for waste heat dissipation. Many studies of the economics and performances of dry and wet/dry cooling methods have been made by the Electric Power Research Institute (EPRI), Battelle, Pacific Northwest Laboratory (PNL), and others. Studies have also been made of the use of less expensive materials of construction and innovative systems. However, in a 1979 study, Johnson (Ref. 2) found that estimated costs for dry cooling were so high that many U.S. power companies believed it more economical to find cooling tower makeup water by purchase of agricultural land for the water rights or by use of treatment plants to recover water from brines, sewerage treatment plant effluents, and other low-quality water.

This paper reviews some of the waste heat dissipation studies and tests initiated in the U.S. during the past two or three years that seem to be of unusual interest or significance. Many of the investigations involve large-scale projects that are fully installed and producing preliminary indications of performance. Unfortunately for this paper, however, final reports and conclusions may not be available until about mid-1982 or later. It should be noted that some of the project schedules mentioned in this paper are subject to the uncertainties of U.S. Department of Energy (DOE) funding.

2. VARIABLE-CAPACITY, OR "FLOATING POWER" OUTPUT

Of all the methods suggested for improving the economics for geothermal power plant waste heat dissipation, variable-capacity, or so-called "floating power", appears likely to have the potential for most immediate acceptance. The concept is one in which a power station allows the net power output of the plant to vary in response to changes in the ambient temperature. Rather than designing for a fixed turbine exhaust pressure that can be maintained year-round, the back pressure is allowed to decrease with lower ambient temperatures, such as occur at night or during the winter months. Unlike steam turbines, turbines using other working fluids can operate with relatively wide-ranging back pressures without serious loss of turbine efficiency. The variable-capacity concept is thus particularly well suited for binary geothermal power plants.

One of the major disadvantages of the "floating power" concept is that western-state utilities have connected loads that peak during the daytime hours and during the air conditioning season, times when the output of the variable-capacity geothermal plant would tend to be the least. Another disadvantage of the concept is that the major equipment is not fully loaded a significant portion of the time, which increases capital costs.

In 1977 Shaffer (Ref. 3) made a thermodynamic study of the performance of a dual-boiling, isobutane power cycle using the variable-output mode of operation as applied to both wet- and dry-cooled sytems. He investigated the performance of a station designed for the climate of Pocatello, Idaho, and developed an equation for relating the net power output of the binary cycle to the wet-bulb temperature (Fig. 2). The Shaffer study was extended by using his equation to estimate the performance of a plant located at Yuma, Arizona. The pertinent climatical data of Pocatello and Yuma are compared in Table 1. On the average, the daily variations in plant energy output on a given day would be 20 to 25%. The seasonal variations, shown in Fig. 3, are larger and can amount to a 40% increase in energy output during the winter months. Over the period of a year the average output of a variable-capacity plant at Pocatello would be about 22% greater than for a fixed-capacity plant, and at Yuma, would be about 28% greater.

The results shown in Fig. 3 apply to stations using wet cooling towers. In direct dry-cooled systems, the turbine back pressure is a function of the dry-bulb rather than the wet-bulb temperature and the system is less efficient overall. The maximum daily variations in the dry-bulb for the two locations studied, shown in Table 1, are based on monthly averages of hourly temperatures. Daily variations are much greater and, at times, can be extreme. It is obvious that a dry-cooled fixed-capacity plant designed for a given dry-bulb temperature would be penalized severely. Whereas Shaffer (Ref. 3) showed the wet-cooled station at Pocatello to gain in energy output by about 20% when variable-capacity power was used, a dry-cooled station was estimated to benefit about 150% from the concept.

A 1981 thermodynamic study made by Fluor Power Services (Ref. 4) for the Geothermal Binary Demonstration Project at Heber, California did not show as great an increase inaverage power output as that mentioned above; nevertheless, the improvement was sufficient to lead to the recommendation that the "floating power" concept be adopted for the project. The study assumes the use of wet cooling towers, a working fluid for the cycle of a 10-90 mixture of isopentane-isobutane, and either axial-flow or radial-flow turbines. In both cases the annual energy output was improved by about 9.5 to 12.6% by use of the concept.

Although the studies of the thermodynamic aspects of "floating power" make it appear attractive, the proof of the concept is in the economic performance. Pines et al. (Ref. 5) made a study in 1978 of "floating power" in which he estimated that a wet-cooled geothermal plant with variable capacity could produce electricity at about 14% less cost than a fixed-capacity plant at the same location. More significantly, he estimated that a dry-cooled variable-capacity plant could produce power at about 35% less cost than a fixed-capacity station.

3. AMMONIA HEAT TRANSPORT FOR DRY-COOLED SYSTEMS

Various methods have been proposed for reducing the cost of dry-cooled heat exchangers, such as the use of plastics and new processes for producing finned surfaces, but to date, none are strikingly cost-effective. Johnson (Ref. 6), however, points out that the heat exchanger represents but only about 30% of the total cost of a dry-cooled system (Table 2). He suggests that a more promising method of reducing costs is to use a phase-change circulating fluid to transport waste heat from the steam turbine condenser to the air-cooled heat exchanger. Because of the improved heat transfer, the piping and the heat exchangers can be smaller, and in many plant layouts, the capital costs can be significantly lower than for systems in which steam is condensed directly in air-cooled coils.

Of the heat transport fluids that can be considered, such as ammonia, water, and various refrigerants and hydrocarbons, Johnson (Ref. 6) showed that ammonia clearly has the best heat transfer and transport properties. It requires significantly less pumping power, and indeed, gravity circulation is feasible. Ammonia has the further advantage that it eliminates freeze-up problems associated with air-cooled coils. Disadvantages of ammonia are that it is a toxic substance and that the system must be leak-tight at test pressures of up to 3 MPa. Several cost studies have been published which indicate cost advantages for the ammonia transport system, such as that by Faletti (Ref. 7). A more recent study by Drost and Huber (Ref. 8) of binary wet/dry systems concludes that it is cost effective to use ammonia as the working fluid in the power cycle as well. In this arrangement, the turbine would exhaust directly into the wet/dry air-cooled coil. The resulting power cost is lower than that of an all-wet ammonia cycle, primarily because of elimination of the circulating water pumps, but the cost is not less than that of an all-wet isobutane power cycle.

EPRI and DOE have jointly funded an Advanced Concepts Test (ACT) at the Pacific Gas and Electric Company's Kern power station in Bakersfield, California, which uses a phase-change, ammonia heat transport system. A simplified flow diagram for the 9-MWe (equivalent) test is shown in Fig. 4. Johnson, of PNL, has discussed the background and overall objectives of the test (Ref. 2) and described the equipment in a preliminary report (Ref. 9). The steam condenser/ammonia boiler, designed and constructed by the Linde Division of Union Carbide Corporation, has condensing steam on the shell side of a horizontal shell-and-tube exchanger and has forced circulation of ammonia through the tubes. Two sets of aluminum air-cooled heat exchangers will be tested: (a) a finned-tube coil supplied by Trane Corporation and (b) a "skived-fin" exchanger manufactured by Curtis-Wright Corporation. The capacity of the Trane coils can be augmented by deluging them with a continuous film of water. Before shutdown of this deluge system, the surfaces of the coil will be rinsed with water treated to have less than 5 ppm of solids to limit deposition of scale during dryout. When the Curtis-Wright coils are in service, augmentation is provided by a commercially available, evaporative-type ammonia condenser.

Construction of the ACT facility was completed in the fall of 1981. By the spring of 1982 it is probable that the results of the first performance testing will be published. Long-range testing will continue, however, and cover about a three-year period. As outlined by Zaloudek (Ref. 10), the tests will cover a broad range of objectives, including evaluating stability, load-following characteristics, maintenance requirements, and compatibility of materials in the system.

4. "BINARY" COOLING TOWER

An innovative method of waste heat disposal developed in the U.S. during the past few years is the so-called "binary" cooling tower. As described by Lancaster and Sanderson (Ref. 11), the tower consists of separate modules, each of which has parallel frames on which $\sim$0.1-mm plastic sheeting membranes are tightly stretched. The spacing between the sheets is about 20 mm and the membranes are typically about 2.5 m wide and 5 m high. The circulated water to be cooled is introduced at the top of the space between two plastic sheets and flows downward as a falling film on the surfaces of the plastic to the bottom of the module, where it is collected and recirculated to the turbine condenser. This primary circulating loop can be operated as either an open or closed system. In the spaces on each side, either air in crossflow or crossflow air plus an evaporating falling water film on the plastic surfaces absorbs the heat conducted through the plastic film, as schematically indicated in Fig. 5. A tower can be arranged so that some modules operate dry and others wet. The air flow passages between the membranes are relatively large and smooth, which results in comparatively low fan power requirements.

The "binary" tower concept is unique in that it is reported to be less susceptible than conventional equipment to scaling, fouling, and corrosion, and that concentrations of as high as 120,000 ppm total dissolved solids can be tolerated in the secondary water circuit. Concentration factors of over 100 can be considered. This aspect allows use of low-quality water for makeup on the secondary side and also makes the tower well suited to applications where the quantity of blowdown water must be kept to a minimum.

The ability of the "binary" tower to operate with low-quality water on the secondary side largely depends upon the water treatment system which is an integral part of each tower installation. Scaling is controlled by treatment of the makeup water to remove scale-causing agents. Biological fouling is retarded by the high salt content in the secondary system and by the fact that any biocides present tend to become more concentrated. Salt formations at wet/dry interfaces are said to be easily washed away. Corrosion is not a great problem in the secondary system because, with the exception of the pumps, it is composed of non-metallic materials. Special alloys can be used in the pump construction. Since the secondary water moves through the tower as a falling film rather than in the conventional splash arrangement, drift from the "binary" tower is said to be negligible.

Lancaster and Sanderson (Ref. 11) compared a "binary" cooling tower with a conventional wet tower and with a conventional wet/dry tower for disposing of about 29 MWt of heat when cooling about 0.63 m^3/s of water through an 11°C range. The "binary" tower annually evaporated about 90% less water than the wet tower and about 15% less than the wet/dry tower. The combined capital and operating costs of the "binary" tower were greater than that of the wet tower but significantly less than that of the wet/dry tower. If the cost of makeup water were very high, and if the water did not require extensive treatment, the "binary" tower could also show a cost advantage over the wet tower. If zero wastewater discharge is required, the study shows that the "binary" tower would clearly be the most cost-effective of the three systems considered if the expense of the evaporative ponds is included in the total cost. Faletti (Ref. 7) made a similar study in 1980 and also showed an economic advantage for the "binary" tower if the evaporative pond is included in the total cost. Faletti believes that the estimated performance factors are reasonably conservative, provided that the falling water films adhere to the plastic. In the first commercial application, a "binary" tower has been installed at the C. B. MacIntosh Generating Station at Lakeland, Florida, in series with a conventional wet-cooling tower. The "binary" tower will be used to concentrate wastewater from the ash pond prior to its evaporation in a solar pond. The unit will be operational in late 1981 or early 1982.

5. STEAM TURBINE BLADING FOR DRY COOLING

Use of dry coils for heat rejection results in higher and more widely variable steam turbine condensing pressures than those associated with wet cooling towers. These exhaust pressures not only impose a penalty on the cycle efficiency because of the reduced range of the expansion process, but also impair the turbine efficiency due to it frequently being operated off the design point. Westinghouse Electric Corporation is said to have new designs for last-stage blading that permit a broader range of exhaust pressures with little or no loss in turbine efficiency while still maintaining the blade vibration within safe limits. As noted by Silvestri (Ref. 12), the higher exhaust-end temperatures associated with higher exhaust pressures must still be considered in the turbine design, but this aspect is not as limiting and the new blading designs have permitted the wide-range turbines to be placed on the market.

6. PHASED COOLING

There may be cost and water savings in using ponds, tanks, or aquifers to store heated condenser circulating water until the nighttime hours when ambient conditions are more favorable for heat rejection to the atmosphere. This is sometimes referred to as "phased cooling." The first large-scale testing of the concept at a geothermal power plant is at the Magma Corporation's 10-MWe binary station at East Mesa, California. The plant has three plastic-membrane-lined storage ponds about 6 m deep, which cover a total area of about 100,000 m^2, and has two spray areas that drain into the ponds. It was originally thought that the spray areas would be less expensive than wet cooling towers of the same capacity, but construction experience has raised some doubts. Reservations have also been expressed regarding the amount of water that will be conserved by the concept because of the evaporation rates from the pond surfaces. More definitive evaluation of the "phased cooling" concept at East Mesa may be available in 1982.

7. ENHANCED CONDENSER HEAT TRANSFER SURFACES

The costs of heat dissipation could be lowered if the turbine condenser surface area could be reduced. One possible method of accomplishing this is to improve the overall heat transfer coefficient through use of vertical tubes having fluted surfaces (Fig. 6). In 1978 Combs et al. (Refs. 13, 14) investigated the performance of vertical tubes with various fluting configurations on the outside surface on which fluorocarbons, ammonia, and isobutane were condensed. The outside composite film coefficients (which include the tube wall resistance) were improved by factors of up to 6 or 7 times over that of smooth tubes. It was also found that "drainoff skirts" located about 60 cm apart to direct the condensate away from the vertical tubes were effective. Cost estimates indicated material costs for vertical, fluted-tube condensers were about 60% of those for horizontal smooth-tube units with the same heat transfer capacity. In 1981 Domingo (Ref. 15) extended the tests to include the effects of internal as well as external fluting, such as that shown in Fig. 6, when condensing Refrigerant-11. The tests indicated an improvement of about 17% in the overall coefficient over that which could be obtained with external fluting only.

The encouraging results obtained at ORNL led to field tests at East Mesa, California and at Raft River, Idaho, as described by Michel and Murphy (Ref. 16). In 1979 tests were made at East Mesa of a 40-tube bundle with tubes having external flutes on which isobutane was condensed. The performance was not as good as that predicted by the earlier laboratory tests when the isobutane supplied to the condenser was evaporated in a direct-contact type boiler. This was attributed to noncondensable gases, water vapor, and fouling of the surfaces. In late 1981 tests were started at Raft River of a 104-tube, vertical, fluted-tube bundle of improved design. Noncondensable gases (primarily nitrogen) are vented at the top of the unit. Preliminary indications are that when the isobutane is supplied by a surface-type boiler, the heat transfer performances approach those obtained in the laboratory tests. When the isobutane is vaporized in a direct-contact boiler, however, the coefficients may be less than 20% of those predicted, again illustrating that condenser effectiveness is a major consideration when using direct-contact heat exchangers. Definitive results of the Raft River tests will be available by early summer or late fall of 1982.

A prototype vertical condenser having 1150 carbon-steel tubes with 60 flutes on the outside surface was installed at the 500 kWe binary-cycle demonstration test at East Mesa. In a comprehensive design report, Llewellyn (Ref. 17) explained how the condenser will draw off the noncondensable gases (primarily carbon dioxide, in this case) at the bottom in an effort to saturate the isobutane condensate with the gases so that they can be vented at the direct-contact boiler. Test results are anticipated by mid-1982.

8. ECONOMIC COMPARISON OF HEAT DISSIPATION SYSTEMS FOR RAFT RIVER

In a 1981 study Bamberger (Ref. 18) compared the capital and operating costs of different methods of disposing of about 36 MWt of waste heat from the 5 MWe binary-cycle geothermal test facility at Raft River, Idaho. Condenser circulating water and wet-cooling-tower makeup at this plant are now obtained from cooled geothermal fluid, which is treated to control scaling and corrosion problems due to high concentrations of silica and chlorides. Four possible methods of heat dissipation were studied: (1) evaporative condensers with isobutane condensing in coils cooled on the outside by evaporation of water, (2) "binary" cooling towers, as described above, (3) air-cooled coils having isobutane condensing on the inside and with the heat transfer augmented by deluging the outside with water when ambient dry-bulb temperatures exceed about 12°C, and (4) a system in which condenser circulating water is cooled in dry coils by air which has first been lowered in temperature by water sprays.

The study assumed a 30-year life for the major equipment and that the existing water-cooled isobutane surface condenser at the Raft River site would be available at no cost for the two methods which use circulating water to transport the waste heat. Operating costs were assumed to consist only of the auxiliary power required for fans and pumps, and that these costs would escalate 8% per year. It was further assumed that an evaporative pond, costing about $15/m^2$, would be used at Raft River to dispose of blowdown water from the water treatment systems and the cooling towers. The cycles of concentration that can be tolerated in each cooling system is therefore an important element in the pond and treatment costs. These two costs are controlling in some cases as to which of the four methods is most cost-effective.

The results of the study are summarized in Table 3. It should be noted that the costs shown in the table serve to compare the four methods with each other, but they are not representative of actual systems. If the cycles of concentration can be kept above about 5 in the evaporative condenser system, it would clearly show the lowest power production cost because of the relatively low capital investment and water treatment costs. If the system were limited to about 3 cycles of concentration, and thus require a large evaporation pond, the total power production cost would be about the same as that of the "binary" cooling tower method. The "binary" tower system, the next lowest in production costs, benefits from relatively low capital and operating costs and from being able to tolerate high levels of concentration. The water treatment costs are relatively high, however. The augmented air-cooled coils have somewhat higher capital and operating costs because of the heat transfer surface required and because of the water treatment costs of providing "zero" hardness water for flushing the coils at the end of deluging cycles. The cooling method using dry coils provided with precooled air is the least economical of those studied because of the extensive heat transfer surface required. Parametric studies, made as an extension of the Bamberger investigation, show that the order or ranking as to power production costs (Table 3), would not change even though the interest rate on investment, the inflation rate, assumed life of the plant, and cost of auxiliary power were all changed within reasonable limits.

While the Bamberger study is perhaps too particularized for Raft River conditions to support general conclusions, it does provide a basis for speculation. For example, if credit were not given for the existing water-cooled isobutane surface condenser, the evaporative condensers and the augmented coil systems would clearly stand out as most economical. If zero waste discharge is not required or if the blowdown could be reinjected, the evaporative condenser system would be at an even better advantage. At sites where makeup water did not require as extensive treatment, the augmented-coil method would be more competitive. The rankings of the systems with regard to water conservation are essentially the reverse of the economic rankings: that is, dry coils with precooled air require the least amount of makeup water and the evaporative condensers require the most water. If the cost of makeup water were high, say $0.50/m^3$, the deluged-coil system would probably be more economical than the other three systems. In summary, each of the systems, with the probable exception of the dry coil using precooled air, could have economic merit under the particular conditions at some geothermal power plant sites.

9. CONCLUSIONS

Variable-capacity operation, ammonia heat transport systems, "binary" cooling towers, and enhanced heat transfer surfaces may help reduce geothermal power station costs and, by offsetting to some extent the expense of dry or wet/dry cooling, may also help conserve water. Other methods, such as use of evapoative condensers, may help a station be more cost-effective, but will not reduce water consumption. Thus, some of the methods have promise in mitigating the heat disposal problems, but when one considers the economic and thermodynamic realities, none of the concepts can be expected to produce a major breakthrough that will, in effect, be an all-purpose solution to the many site-specific difficulties regarding waste heat dissipation.

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TABLE 1. TEMPERATURE DATA FOR POCATELLO, ID. AND YUMA, AZ.[a]

	POCATELLO, ID.[b]	YUMA, AZ.[c]
Design wet-bulb (5%)	16.1	25.0
Design dry-bulb (5%)	31.1	41.1
Yearly-average wet-bulb	3.4	13.4
Yearly-average dry-bulb	8.4	23.3
Dry-bulb max. daily variation	17.2	15.0
Dry-bulb max. seasonal variation	26.7	22.2

a. All temperatures in °C.
b. Based on average temperatures in 1970.
c. Based on average temperatures in 1966.

TABLE 2. DISTRIBUTION OF DRY-COOLING SYSTEM COSTS[a]

Heat Exchanger	30%
Structures	15
Fans	20
Piping and Pumps	20
Condenser	15
	100%

a. From Johnson (Ref. 6)

TABLE 3. COMPARISON OF WASTE HEAT SYSTEMS FOR RAFT RIVER, IDAHO[a]

	Evap. Cond.	"Binary" Tower	Augm. Coil	Coil/Pre-cooled Air
Cycles of concentration	10-3	67-10	10-5	10-5
Pond size, hectares	9.7-44	0.8-5.0	1.9-4.3	1.9-4.2
Makeup rate, 1000 m^3/yr	474	211	106	105
Capital costs[b]				
Heat exchanger unit	233	607	1264	3210
Structures, fans, pumps	1095	1378	1785	2959
Elec. and instru.	344	182	62	434
Water treatment				
Closed loop		19		19
Open loop	57	280	311	57
Zero hardness rinse			235	
Evaporation pond	582-2640	48-300	114-258	114-252
Total capital cost	2311-4369	2514-2766	3771-3915	6793-6931
Operating costs[c]				
Annual	239	294	310	458
30-yr present worth[d]	4669	5743	6056	8946
Total capitalized cost in $1000	6980-9038	8257-8509	9827-9971	15739-15877
Levelized power production cost, mills/kWh[e]	17.7-22.9	20.9-21.6	24.9-25.3	39.9-40.2

a. Adapted from Bamberger (Ref. 17)
b. All costs given in $1000, except as noted.
c. Operating costs are for auxiliary power only, and are assumed to escalate at 8% per year.
d. Capitalized at 8% interest rate on onvestment.
e. Based on 80% plant factor and 5 MWe net output.

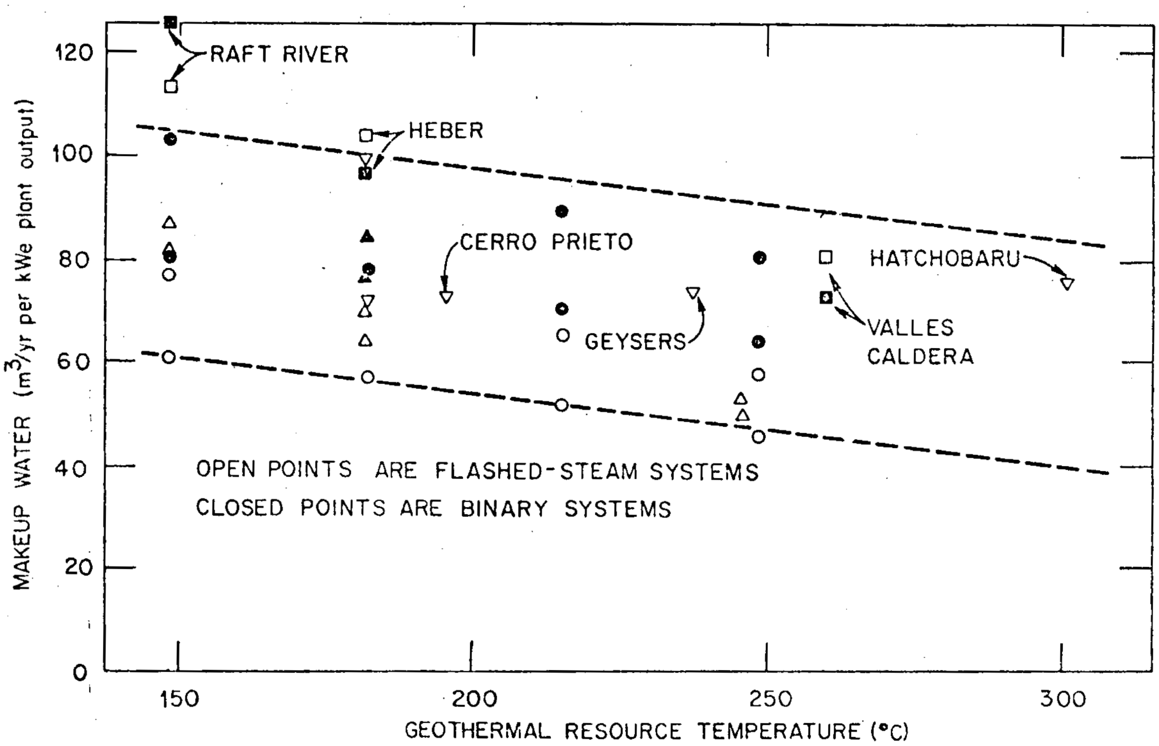
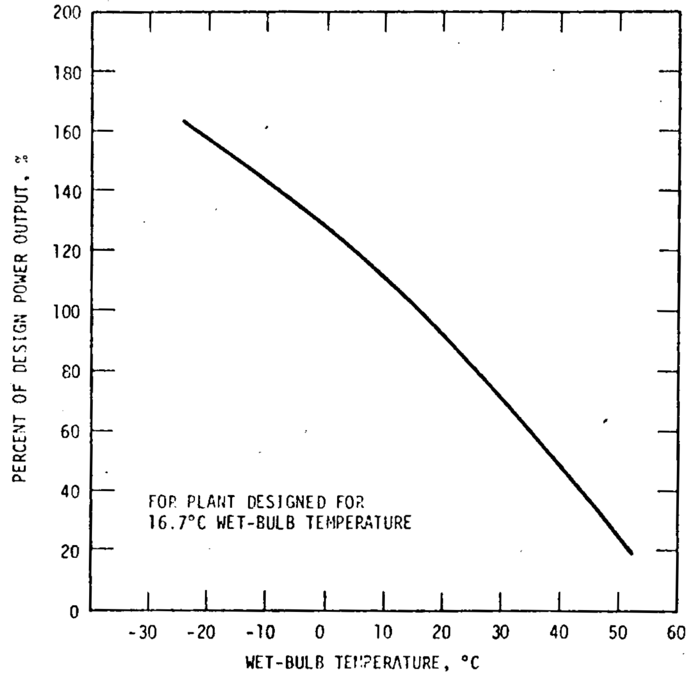


FIGURE 1. ANNUAL-AVERAGE COOLING TOWER MAKEUP WATER NEEDED AT GEOTHERMAL ELECTRIC GENERATING STATIONS. (Source: Robertson, Ref. 1)



$$\%P = 128.6143 - 1.528935T - 0.01004658T^2 - 8.83452\times10^{-5}T^3 + 94.31868\times10^{-8}T^4$$, where T = WET-BULB TEMP., °C

FIGURE 2. EFFECT OF WET-BULB TEMPERATURE ON NET POWER OUTPUT OF DUAL-BOILING ISOBUTANE POWER CYCLE. (Adapted from Shaffer, Ref. 3)

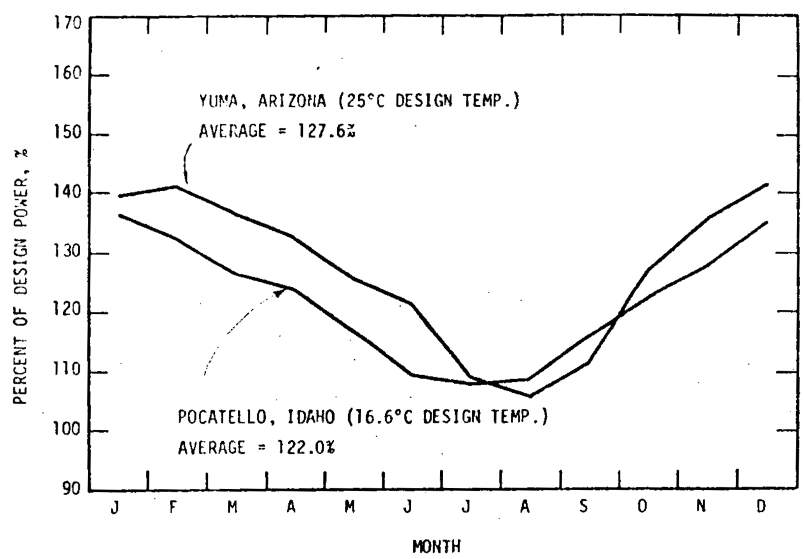


FIGURE 3. MONTHLY VARIATION OF NET POWER AS PERCENT OF DESIGN POWER OF DUAL-BOILING ISOBUTANE POWER CYCLE. (Adapted from Shaffer, Ref. 3)

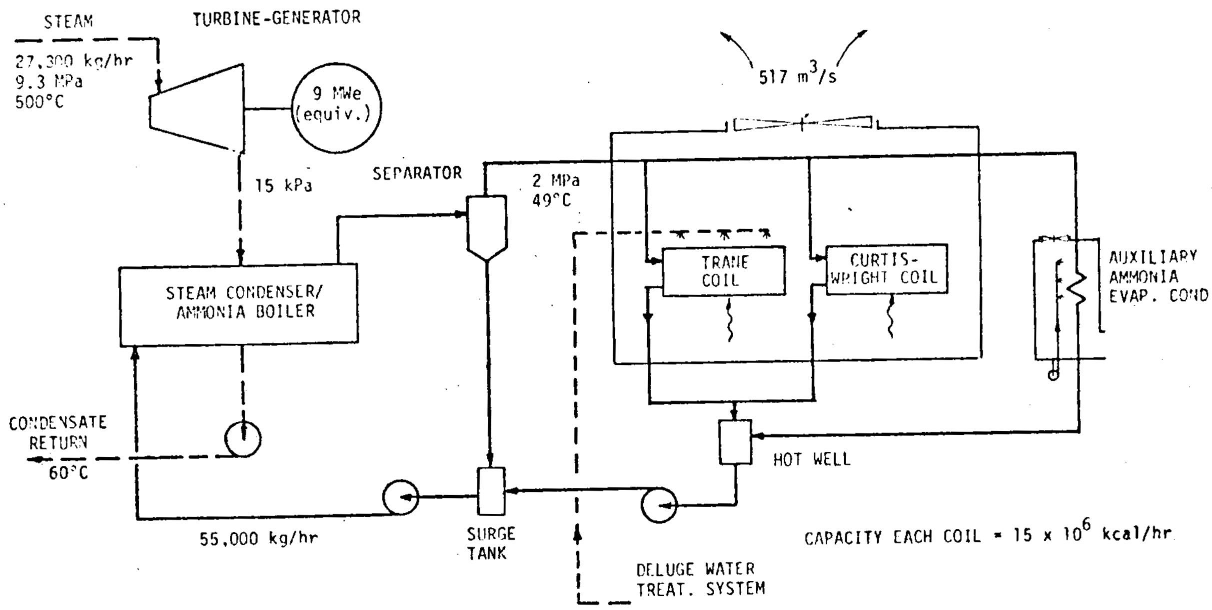


FIGURE 4. SIMPLIFIED FLOW DIAGRAM OF AMMONIA HEAT TRANSPORT SYSTEM FOR ADVANCED CONCEPTS TEST AT KERN POWER STATION. (Adapted from Johnson, Ref. 9)

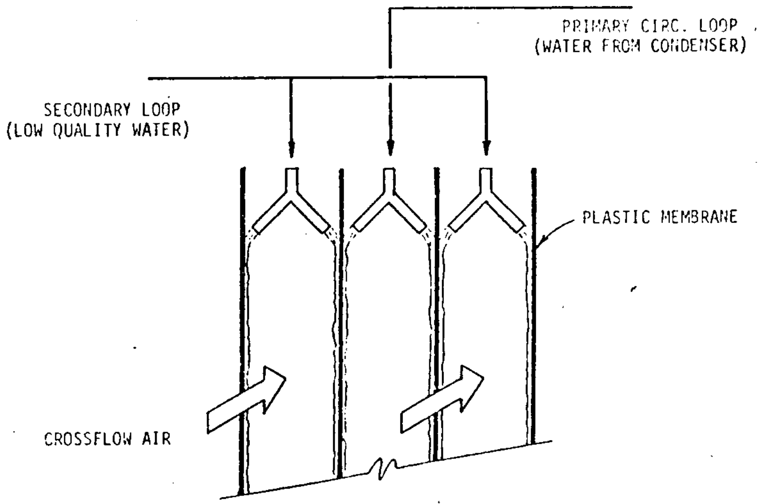


FIGURE 5. SCHEMATIC REPRESENTATION OF PLASTIC MEMBRANE, OR "BINARY", COOLING TOWER.
(Adapted from Lancaster, Ref. 10)

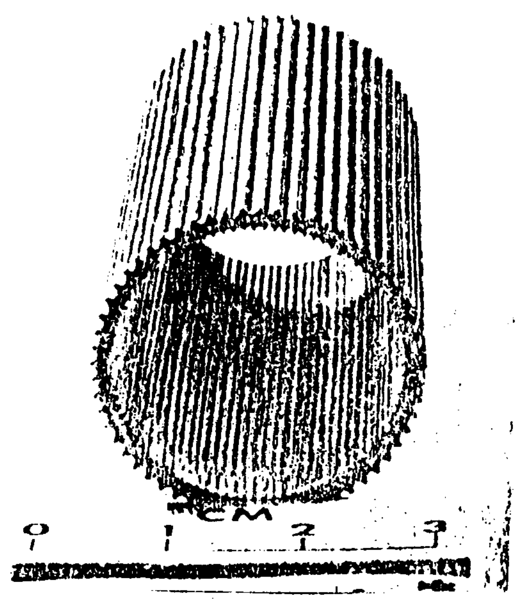


FIGURE 6. ENHANCED-SURFACE CONDENSER TUBE.
(Source: Domingo, Ref. 14)