COST BENEFITS FROM APPLYING ADVANCED HEAT
REJECTION CONCEPTS TO A WET/DRY-COOLED
BINARY GEOTHERMAL PLANT

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FOREWORD

The Dry Cooling Enhancement Program at Pacific Northwest Laboratory (PNL) was initiated with a program scope that included the following near-term and ultimate emphasis.

Near Term Objectives:

Develop economic and performance models for cost optimization of total heat rejection systems using dry and dry/wet cooling.

Analyze and disseminate operating experience and existing dry-cooled plant performance.

Demonstrate certain features of existing technology equipment to provide confidence for specification by utilities.

Ultimate Objective:

Promote water conservation through industry use of dry cooling by developing and demonstrating the reliability of lower cost systems. The development of advanced dry/wet systems is also considered to be within this scope.

The following documents have been issued, reporting the results of the work toward these objectives.

Cost optimization of dry-cooled heat rejection systems:

A REVIEW AND ASSESSMENT OF ENGINEERING ECONOMIC STUDIES OF DRY-COOLED ELECTRICAL GENERATING PLANTS. B. C. Fryer, BNWL-1976, March 1976.

HEAT TRANSFER AND PRESSURE DROP CHARACTERISTICS OF DRY TOWER EXTENDED SURFACES. PART I: HEAT TRANSFER AND PRESSURE DROP DATA. PFR Engineering Systems, Inc., PFR 7-100, March 1976.

HEAT TRANSFER AND PRESSURE DROP CHARACTERISTICS OF DRY TOWER EXTENDED SURFACES. PART II: DATA ANALYSIS AND CORRELATION. PFR Engineering Systems, Inc., PFR 7-102, June 1976.

Analysis of performance of existing dry-cooled plants:

DRY COOLING TOWER PROGRAM: RESULTS OF INDUSTRIAL CONTACTS THROUGH AUGUST 1964. BNWL-1878, November 1, 1974.

A SURVEY OF MATERIALS AND CORROSION PERFORMANCE IN DRY COOLING APPLICATIONS. A. B. Johnson, Jr., D. R. Pratt and G. E. Zima, BNWL--1958, March 1976.

EUROPEAN DRY COOLING TOWER OPERATING EXPERIENCE. J. G. DeSteeze and K. Simhan, BNWL-1955, March 1976.

MATHEMATICAL AND EXPERIMENTAL INVESTIGATIONS OF DISPERSION AND RECIRCULATION OF PLUMES FROM DRY COOLING TOWERS AT WYODAK POWER PLANT IN WYOMING. Y. Onishi and D. S. Trent, BNWL-1982, February 1976.

ALUMINUM ALLOY PERFORMANCE UNDER DRY COOLING TOWER CONDITIONS. A. B. Johnson, Jr., S. Begaj, M. W. Martini, and R. P. May, PNL-2392, December 1977.

Advanced dry (dry/wet)-cooled systems:

PRELIMINARY EVALUATION OF WET-DRY COOLING CONCEPTS FOR POWER PLANTS. W. B. Loscutoff, BNWL-1969.

COMPATIBILITY OF AMMONIA WITH CANDIDATE DRY COOLING SYSTEM MATERIALS. D. R. Pratt, BNWL-1991, April 1976.

SCALE FORMATION IN DELUGED DRY COOLING SYSTEMS. D. R. Pratt, BNWL-2060, March 1976.

AMMONIA AS AN INTERMEDIATE HEAT EXCHANGE FLUID DRY FOR DRY-COOLED TOWERS. R. T. Allemann, B. M. Johnson, and G. C. Smith, BNWL-SA-5997, September 1976.

AUGMENTED DRY COOLING SURFACE TEST PROGRAM: ANALYSIS AND EXPERIMENTAL RESULTS. H. L. Parry et al. PNL-2746, September 1979.

A group of reports (including this report) has been issued that serves the dual purpose of: 1) developing cost optimization models for dry cooling systems based on available technology and 2) comparing the results of analyzing the cost of these systems with the projected cost of several advanced dry and dry/wet systems. Included in this group are:

AN ENGINEERING AND COST COMPARISON OF THREE DIFFERENT ALL-DRY COOLING SYSTEMS. B. C. Fryer, D. W. Faletti, Daniel J. Braun, David J. Braun and L. E. Wiles, BNWL-2121, September 1976.

A STUDY OF THE COMPARATIVE COSTS OF FIVE WET/DRY COOLING TOWER CONCEPTS. F. R. Zaloudek, R. T. Allemann, D. W. Faletti, B. M. Johnson, H. L. Parry, G. C. Smith, R. D. Tokarz and R. A. Walter, BNWL-2122, September 1976.

DRY COOLING OF POWER GENERATING STATIONS: A SUMMARY OF THE ECONOMIC EVALUATION OF SEVERAL ADVANCED CONCEPTS VIA A DESIGN OPTIMIZATION STUDY AND A CONCEPTUAL DESIGN AND COST ESTIMATE. B. M. Johnson, R. T. Allemann, D. W. Faletti, B. C. Fryer and F. R. Zaloudek, BNWL-2120, September 1976.

COSTS AND COST ALGORITHMS FOR DRY COOLING TOWER SYSTEMS. P. A. Ard, C. H. Henager, D. R. Pratt and L. E. Wiles, BNWL-2123, September 1976.

A USER'S MANUAL FOR THE BNW-I OPTIMIZATION CODE FOR DRY-COOLED POWER PLANTS. David J. Braun, Daniel J. Braun, Warren V. DeMier, D. W. Faletti, and L. E. Wiles, BNWL-2180, January 1977.

COMPARATIVE COST STUDY OF FOUR WET/DRY COOLING CONCEPTS THAT USE AMMONIA AS THE INTERMEDIATE HEAT EXCHANGE FLUID. R. D. Tokarz, Daniel J. Braun, B. M. Johnson, R. T. Alteman, David J. Braun, H. L. Parry, G. C. Smith and F. R. Zaloudek, PNL-2661, September 1978.

AN ENGINEERING AND COST ANALYSIS OF A DRY COOLING SYSTEM AUGMENTED WITH A THERMAL STORAGE POND. M. K. Drost and R. T. Allemann, PNL-2745, September 1978.

A USER'S MANUAL FOR THE BNW-II OPTIMIZATION CODE FOR DRY/WET-COOLED POWER PLANTS. Daniel J. Braun, Judith A. Bamberger, David J. Braun, Duane W. Faletti, Lawrence E. Wiles, PNL-2674, Vol. I, May 1978.

A DESCRIPTION AND COST ANALYSIS OF A DELUGE DRY/WET COOLING SYSTEM. L. E. Wiles et al. PNL-2498, June 1978.

Four reports have been issued with consider the future need for any cooling and the potential benefit/cost ratio of a large-scale demonstration.

AN OVERVIEW OF ECONOMIC, LEGAL, AND WATER AVAILABILITY FACTORS AFFECTING THE DEMAND FOR DRY AND WET/DRY COOLING OF THERMAL POWER PLANTS. P. L. Hendrickson, BNWL-2268, June 1977.

AN OVERVIEW OF ECONOMIC, LEGAL, AND WATER AVAILABILITY FACTORS AFFECTING THE DEMAND FOR DRY AND WET/DRY COOLING OF THERMAL POWER PLANTS. P. L. Hendrickson, BNWL-2268, September 1978.

ESTIMATION OF BENEFITS FROM DEMONSTRATING ADVANCED DRY COOLING TECHNOLOGY: A FRAMEWORK AND PARTIAL ANALYSIS. J. W. Currie and T. J. Foley, BNWL-2182, April 1977.

POTENTIAL USE FOR DRY COOLING IN SUPPORT OF ADVANCED ENERGY
GENERATION SYSTEMS. D. W. Mayer, E. M. Arnold and R. T. Allemann,
PNL-3149, September 1979.

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CONTENTS

FOREWORD	iii
ACKNOWLEDGMENTS	vii
1.0 INTRODUCTION	1.1
2.0 SUMMARY AND CONCLUSIONS	2.1
2.1 WET/DRY AMMONIA SYSTEM	2.1
2.2 BINARY COOLING TOWER SYSTEM	2.3
3.0 WET/DRY SYSTEMS	3.1
3.1 SELECTION OF THE MOST PROMISING ADVANCED HEAT REJECTION SYSTEM	3.3
3.2 DESIGN BASIS AND METHOD	3.6
3.3 PLANT DESCRIPTION	3.8
3.4 DISCUSSION OF WET/DRY SYSTEMS	3.14
4.0 THE BINARY COOLING TOWER SYSTEM	4.1
4.1 SYSTEM DESCRIPTION	4.2
4.2 PLANT DESCRIPTION	4.2
4.3 PERFORMANCE AND ECONOMIC EVALUATION	4.7
4.4 BUSBAR ELECTRICAL COST COMPARISON	4.8
5.0 CONCLUDING COMMENTS	5.1
REFERENCES	Ref-1

FIGURES

3.1	Direct Wet/Dry Cooling System	3.2
3.2	Indirect Wet/Dry Cooling System	3.2
3.3	Ammonia Dry Cooling System	3.3
3.4	Indirect Heat Rejection with Wet Augmentation	3.5
3.5	Direct Heat Rejection System with Wet Augmentation	3.5
3.6	Ammonia Heat Rejection System with Wet Augmentation	3.5
4.1	Binary Cooling Tower System Tower Showing Module Location	4.3
4.2	Binary Cooling Tower Module Detail	4.3
4.3	Secondary Water Circulation System	4.4
4.4	Flow Diagram-Binary Cooling Tower System Using Agricultural Waste Water	4.5

TABLES

3.1	Cost Comparison of Direct Ammonia Heat Rejection Systems	3.6
3.2	Holt/Procon Binary Plants Design	3.9
3.3	Selected BNWGEO Inputs	3.9
3.4	Wet/Dry Heat Rejection Systems	3.10
3.5	Operating Parameters for Wet/Dry Plant-- 215 Acre-Feet (9% Wet)	3.11
3.6	Operating Parameters for Wet/Dry Plant-- 475 Acre-Feet (20% Wet)	3.12
3.7	Operating Parameters for Wet/Dry Plant-- 710 Acre-Feet (31% Wet)	3.13
3.8	Summary of Results	3.15
3.9	Sensitivity of BNWGEO Incremental Cost to Size of Gas Turbine Contingent	3.16
3.10	Relative Costs of Electricity	3.17
3.11	Percent Difference in Electrical Costs Compared to a Binary Plant with an Ammonia Cooling System	3.18
4.1	New River Water Composition	4.5
4.2	Binary Cooling Tower System Operation	4.6
4.3	Water and Waste Disposal Requirements of Three Systems Using Agricultural Waste Water (5000 ppm TDS)	4.9
4.4	Cost of Electricity Using Agricultural Waste Water and Zero Discharge	4.10

COST BENEFITS FROM APPLYING ADVANCED HEAT REJECTION CONCEPTS TO A WET/DRY-COOLED BINARY GEOTHERMAL PLANT

1.0 INTRODUCTION

Water availability may limit the development of geothermal resources. Most geothermal power sites are located in areas of little precipitation. In addition, because of their lower efficiency, such plants require about four times more water for cooling than do fossil or nuclear plants of the same net power. Use of wet/dry or dry cooling could eliminate this constraint. However, studies by R. W. Beck (Mitchell, Horsak, and Porter, 1978) and United Engineers & Construction (1977) show that use of conventional dry and wet/dry heat rejection systems substantially increases the cost of electricity from geothermal plants.

The U.S. Department of Energy (DOE) Division of Geothermal Energy has assisted in funding a study utilizing Pacific Northwest Laboratory (PNL) experience in advanced dry and dry/wet cooling analysis to determine whether advanced concepts can significantly reduce the costs of dry and dry/wet systems. This report describes the study and presents the findings.

Three types of geothermal power plants exist: dry steam, flashed steam, and binary. The dry-steam plant is more economical and can require virtually no water for cooling because the condensate can be evaporated in the towers if it is not required for reinjection. Reinjection generally is not a critical consideration in dry-steam geothermal reservoirs. Unfortunately, only a small fraction of geothermal resources are dry-steam. Flashed steam and binary systems use the much more common, lower temperature geothermal resources. In the flashed steam system, the geothermal brine is passed through an orifice and allowed to flash; the resulting steam is passed through the turbine. The flash steam system, like the dry steam system, can use the condensate to cool the plant. However, if it is necessary to reinject all of the condensate, water for cooling the plant must be provided. Reinjection is generally a more critical consideration with hot water geothermal reservoirs. The binary system

uses an intermediate fluid. The geothermal brine vaporizes the fluid, which is passed through the turbine and condensed. Condensate evaporation cooling is not applicable to this concept. In short, dry-steam systems, the most economical, are at least commonly available. Flashed steam systems, generally more economical than binary systems for temperature above 200°C, do not require water for cooling if the condensate does not have to be reinjected. Finally, binary systems, the most economical for the lower geothermal temperatures, always require a source of water for conventional evaporative cooling. For this reason it was decided to study the binary system.

A number of advanced concepts were screened. For the case in which a limited high quality water was available for evaporative cooling, the ammonia system, found to be the most promising advanced system for fossil and nuclear plants, was selected because no identifiable difference was found (between the demands of a geothermal plant and those of a fossil or nuclear-fueled plant) that would change the order of ranking of the competing advanced concepts. For the case in which an abundant amount of poor quality water is available, the selection was the Binary Cooling Tower (BCT), under development by Tower Systems Incorporated, Tacoma, Washington (Slate, Zeien, and Sanderson 1980; Lancaster and Sanderson 1979; Sanderson, Lancaster, and Bostjancic 1980). The BCT system, like a conventional wet tower, cools by evaporation. However, when used with water of poor quality, it produces much less blowdown than conventional towers. The BCT concept was selected for study because, if it proves feasible, it could make possible the use of low quality waters in a zero discharge mode at a cost perhaps not too much larger than conventional towers using high quality water.

These systems are described and evaluated separately in this report because the ammonia dry/wet system and the BCT system would be considered prime candidates under different conditions. The dry/wet system would be considered if the availability of water, of any quality, were very limited; while the BCT would be considered if water of poor quality, but adequate quantity, were available.

2.0 SUMMARY AND CONCLUSIONS

This section briefly summarizes the work performed in this study, then presents the conclusions based on the evaluation findings.

2.1 WET/DRY AMMONIA SYSTEM

Optimized ammonia heat rejection system designs were carried out for three water allocations equivalent to 9, 20 and 31% of that of a 100% wet-cooled plant. The Holt/Procon design of a 50-MWe binary geothermal plant for the Heber site was used as a design basis.

Because optimal cooling loop parameters are considerably different for a geothermal plant than for a fossil plant, optimizations were conducted using the BNWGEO code, a modification of a PNL-developed code for optimizing wet/dry designs of fossil and nuclear plants.

The optimization process took into account the penalties for replacement power, gas turbine capital, and lost capacity due to increased heat rejection temperature, as well as added base plant capacity and fuel to provide fan and pump power to the heat rejection system. Descriptions of the three plant designs are presented. For comparison, a wet tower loop was costed out for a 100% wet-cooled plant using the parameters of the Holt/Procon design.

Wet/dry cooling was found to increase the cost of electricity by 28% above that of a 100% wet-cooled plant for all three of the water allocations studied (9, 20, and 31%). This insensitivity of busbar electrical cost to decreasing water availability resulted from the cost of the wet loop decreasing with water availability, thereby offsetting increases in the cost of the dry cooling loop. This is so because the cost of the wet loop is determined primarily by its required duty on the hottest day. For example, with a 31% wet/dry allocation, the wet loop transferred 98% of the heat on the hot day compared to only 68% at the 9% wet/dry design. As a result, although the cost of the dry tower loop was higher for the 9% wet/dry design, the cost of the wet loop was considerably smaller.

In contrast, to this constancy of busbar power cost with the ammonia system, the cost of the state-of-the-art system for binary plants as reported by Mitchell, Horask, and Porter (1978) increased with decreasing water allocation, ranging from 30% added cost at 31% wet/dry to 62% added cost at 9% wet/dry. As a result, the ammonia system showed a 27% cost advantage over that of the direct system at 9% water allocation, decreasing to 7% cost advantage at the 20% water allocation and 2% cost advantage at 31% water allocation. The true impact of potential of the ammonia system is perhaps better reflected in the change in the incremental cost of electricity--the measure normally used for comparing heat rejection systems. The ammonia system has the potential of reducing the incremental cost of wet/dry cooling of binary geothermal power plants by 15% for a 31% wet/dry allocation, by 25% for a 21% wet/dry allocation, and by 55% for a 7% wet/dry allocation. Another way of looking at these results is that, for the same cost penalty that conventionally cooled wet/dry binary plants have with a 30% wet/dry allocation, it is possible to operate an ammonia plant with only 10% of the wet/dry allocation. This would permit a tripling of the power for a given amount of water. The benefits would be even larger if zero discharge were required, as water costs and waste disposal costs (evaporate ponds) were not included in this study.

The cost benefits indicate that the ammonia wet/dry system warrants further study. It is recommended that these studies initially concentrate on obtaining good comparative costs between the ammonia system and conventional wet/dry cooling systems. This would require more detailed designs of these systems than are currently available. All designs should be on a common basis so that meaningful cost comparisons can be made.

Although it is beyond the scope of this study, an investigation is warranted to determine if the cost of a wet/dry direct system for binary plants could be reduced by selection of a working fluid specifically chosen for wet/dry operation. For example, if the penalty of using ammonia as a working fluid is sufficiently small in terms of cycle efficiency, considerable savings in the total power system, including heat rejection, could result. Not only would the need for the condenser-reboiler, with its cost and large terminal temperature

difference (TTD), be eliminated, but the cost and TTD of the parallel water-cooled condenser would be much lower. This lower condenser TTD would result in a lower-cost wet cooling tower. Consequently, the search for an optimal working fluid for wet/dry cooled geothermal plants should certainly be considered by those conducting cycle studies.

2.2 BINARY COOLING TOWER SYSTEM

The advanced binary cooling tower (BCT) system has been demonstrated at Nevada Power's Sunrise Station where it was used to concentrate the blowdown from conventional towers by a factor of twenty. This system can be operated at solids contents of over 10% because of its configuration, use of nonmetallic components, and the use of appropriate water treatment. Heat transfer from the condenser coolant water to the evaporating coolant water is through polyester films, thereby providing isolation to the condenser loop. Successful operation of the BCT system would make it possible to use low quality water to cool geothermal plants. The cost of solar ponds, to provide an environmentally-acceptable discharge of effluents, is greatly reduced by the smaller blowdown quantities. Examples of low quality water that could be used for cooling include agricultural waste water and brackish groundwater.

The application selected for a preconceptual evaluation of the BCT system was the use of agricultural waste water from the New River, located in California's Imperial Valley, to cool a 50-MWe binary geothermal plant. The same design basis and ground rules used to evaluate the wet/dry systems were used for the BCT system. Technical and cost evaluations at the preconceptual level indicated that performance estimates provided by Tower Systems Incorporated (TSI) were reasonable and that TSI's tower cost, although 2 to 19% lower than PNL estimates, was also reasonable.

Electrical cost comparisons were made among the BCT system, a conventional 100% wet system, and a 9% wet/dry ammonia system, all using agricultural waste water with solar pond disposal. The BCT system cost the least, yielding a cost of electricity only 13% above that of a conventional wet system using high quality water and 14% less than either the conventional 100% wet or the 9% wet/dry ammonia system. An analysis of the cost uncertainties indicates that it

is unlikely that the BCT system would lose its economic advantages if the BCT system operates reasonably reliably and performs as predicted by the correlation and assumptions used in the PNL technical evaluation. Although the Sunrise test indicates the BCT system can be operated successfully for waste water treatment, PNL has not had the opportunity to review the Sunrise test data or TSI in-house data to verify that the BCT system would perform as indicated by this preliminary study. While PNL can give only a conditional endorsement at this time, it is concluded that the BCT system promises significant economic advantages if low quality water is the only water available. In this situation it may make possible the development of geothermal resources that might otherwise not be developed at all.

It is recommended that both the wet/dry ammonia system and the BCT system be studied further with the intent of demonstrating these technologies if future study results are positive. A detailed study of several geothermal sites that have a good probability of being developed within the next 10 to 15 years should be made to determine which advanced concept is most applicable to each site. Such a study would not only provide information on the need for such systems, but would provide the groundwork for the demonstrations.

3.0 WET/DRY SYSTEMS

A brief summary of the heat rejection concept discussed in this report is appropriate. A wet/dry system combines evaporative cooling, as with a conventional wet cooling tower, with air cooling without evaporation (i.e., with an air-cooled heat exchanger). The purpose is to avoid 1) the need for a very large air-cooled heat rejection system just to reject the design heat load during the hottest hour of the year or, conversely, 2) the significant loss of power during the hottest hour. If the dry-cooled portion of the system (i.e., the air-cooled heat exchanger) is a conventional design, it will either condense the turbine exhaust steam directly-- designated a direct system (Figure 3.1) - or it will cool circulating water, which, in turn, is used to condense the steam-- designated an indirect system (Figure 3.2). The same distinction may be made if the turbine uses a working fluid other than steam, such as isobutane at the Raft River project.

A third alternative is to cool a circulating fluid other than water, which condenses in the air-cooled heat exchanger like the direct system, but is still isolated from the turbine. The ammonia dry cooling system is of this type; exhaust steam from the turbine is first condensed by circulating ammonia in the tubes of a heat exchanger not unlike a conventional condenser. The ammonia is partially vaporized and the two-phase mixture flows to a phase separation. The liquid ammonia is pumped back to the condenser/reboiler to be further vaporized, while the vapor is forced to flow to the air heat exchanger in the cooling tower because the ammonia temperature in the tower heat exchanger is less than at the reboiler (hence, the corresponding ammonia (saturation) pressure is lower). The rejection of heat to the air causes the ammonia to condense; the liquid falls to a hot well and is pumped back to the condenser/reboiler. Figure 3.3 is a schematic diagram of such a heat rejection system.

For conventional power plants, an ammonia phase-change dry cooling system is believed to be potentially lower cost than state-of-the-art dry cooling designs of the indirect (circulating water) type because of four factors.

FIGURE 3.1. Direct Wet/Dry Cooling System

FIGURE 3.2. Indirect Wet/Dry Cooling System

FIGURE 3.3. Ammonia Dry Cooling System

- much lower power requirements for pumps to circulate the cooling fluid
- smaller heat exchangers in the cooling tower because the circulating fluid (ammonia vis-a-vis water) gives up heat isothermally so the average temperature driving force is markedly higher
- smaller piping to circulate the ammonia from the turbine condenser out to the cooling tower
- no requirements for safety systems to prevent freeze-up at the cooling tower.

3.1 SELECTION OF THE MOST PROMISING ADVANCED HEAT REJECTION SYSTEM

The studies to date have investigated dry and wet/dry cooling of binary systems using both indirect and direct cooling systems. With the indirect system, the working fluid is cooled by a water loop, which is, in turn, cooled by dry towers augmented by an evaporatively-cooled tower (Figure 3.4). With the direct system, the binary fluid is condensed directly in the dry tower and wet augmentation is accomplished by a water-cooled condenser with its associated wet tower (Figure 3.5).

After screening the advanced concepts studied by the DCE Program over the past 5 years as possible candidates for fossil or nuclear plants, it was concluded that there was no identifiable difference between the demands of a geothermal plant and those of a fossil or nuclear fueled plant that would change the order of ranking of the competing advanced systems. It was, therefore, concluded that the ammonia system (Figure 3.6) was the most promising of the advanced concepts for dry and for wet/dry cooling of geothermal power plants unless water quality imposed further restrictions on the technology that could be used.

By analogy to the work done by the DCE Program for fossil and nuclear plants, it was clear that the ammonia system would be significantly less expensive than the indirect system (Figure 3.4). However, it was not clear whether the ammonia system (Figure 3.5) was less costly than the direct condensing system (Figure 3.6).

Ammonia evidences greater density, heat of vaporization, and lower temperature drop for a given pressure drop compared to those of the hydrocarbons under consideration for binary plants. Thus, the ammonia systems would have lower piping and pump costs and lower auxiliary power requirements for pumping than the direct system. On the other hand, the ammonia system requires a condenser-reboiler, which adds to the expense and reduces the temperature difference at the dry tower. Therefore, a rough costing study was made using an optimized 30% wet/dry deluged ammonia heat rejection system design for a 1000-MWe fossil plant generated by the BNW-II computer code (Braun 1978). The ammonia system's cost were left unchanged (Table 3.1). Credit was given to the direct condensing system (the working fluid was taken to be isobutane) for the temperature difference across the condenser-reboiler and for the temperature drop of the ammonia caused by the pressure drop between the condenser-reboiler and the dry tower. To keep the plants on a comparable basis, the temperature of the isobutane entering the dry tower was kept the same as that of the ammonia entering the dry tower. This effectively set a limit on pressure drop of the isobutane vapor lines. The sevenfold increase in supply piping cost given in Table 3.1 reflects the much larger piping required for isobutane because of its lower heat of vaporization and higher temperature drop for a given pressure

FIGURE 3.4. Indirect Heat Rejection System with Wet Augmentation

FIGURE 3.5. Direct Heat Rejection System with Wet Augmentation

FIGURE 3.6. Ammonia Heat Rejection System with Wet Augmentation

drop compared to ammonia. The size of the return piping was determined on a constant horsepower basis. A better than twofold cost increase resulted.

This costing study had its limitations. For example, the effect of isobutane's lower condensing coefficient on the cost of the ammonia system's condenser-reboiler and on the cost of the isobutane's system's dry tower was neglected as was the cost of redesigning the dry tower for the direct system to reduce pressure drops within the dry tower to acceptable levels. Although it was not possible to determine whether the cost differential between the ammonia and the direct system would be greater or smaller than the 26% found given in Table 3.1, the ammonia system certainly warranted further study.

TABLE 3.1. Cost Comparison of Direct and Ammonia Heat Rejection Systems

<u>Component</u>	<u>Costs (thousands of dollars)</u>	
	<u>Direct System</u>	<u>Ammonia System</u>
Condenser-Reboiler	0	7,900
Separator	0	1,100
Supply Piping	21,700	3,000
Return Piping	2,700	1,100
Pump Station	1,600	900
Balance of System	<u>31,800</u>	<u>31,800</u>
	57,800	45,800

3.2 DESIGN BASIS AND METHOD

The computations summarized above indicated that the ammonia system was less costly for wet/dry systems using deluging. However, more accurate information at several wet/dry levels was needed. It was decided to model the plant after the 50-MWe binary geothermal plant designed by Holt/Procon for the Heber site (EPRI 1978). For simplicity, the working fluid was taken to be 100% isobutane rather than the 80% isobutane-20% isopentane used in the Holt study.

Optimal cooling loop parameters are significantly different for a geothermal plant than for a fossil plant. Therefore, the BNW-II code, developed by PNL to optimize heat rejection systems for fossil and nuclear power plants, was

modified to obtain optimal designs. This modified code, henceforth called BNWGEO, did not have the capability of designing and costing out the wet tower loop. In effect it determined the optimal operating conditions for a plant with a given allocation of water for evaporative cooling that was provided with a zero cost wet cooling tower loop. An optimal wet cooling tower loop (condenser, piping, pumps, wet cooling towers, required fan and pump power) was designed for the plant. The capital and operating costs were then used to obtain the cost of electricity.

The BNWGEO code uses the same utility model as that found in the BNW-II codes (Braun et al. 1978). In this model, the utility must meet a fixed demand for a fraction of the year equal to the capacity factor. The downtime of the utility is distributed uniformly throughout the year. Combustion turbines provide the makeup power whenever the power production of the geothermal plant falls below that of the fixed demand because of high ambient temperatures.

The most economical way to operate within the constraints of the utility model is for the plant to maintain a constant back pressure whenever wet augmentation is used. (This constant back pressure minimizes the size of the gas turbine contingent required). As the ambient temperature falls below the minimum at which wet augmentation is used, the turbine back pressure falls as the turbine exhaust temperature "tracks" the ambient temperature. Under certain conditions, the plant, when operated all-dry at low temperature, may deliver more than the fixed utility load. Under these circumstances, no credit is given for the surplus power because no market exists. However, credit is given for reduced fuel consumption--in this case, lower geothermal energy usage.

Power for the heat rejection system's fans and pumps is provided by the geothermal plant. The size of the plant plus its heat rejection system is "scaled up" to meet this need. Braun et al. (1978) give a detailed description of the utility model and the computation of the incremental cost, as well as the computational procedure followed by the BNW-II code.

The code computes the incremental cost of the electricity from the plant. This incremental cost includes 1) the cost of the capital for the cooling system, the gas turbine, and for the added plant capacity resulting from increased

heat rejection temperatures and required for supplying power to the fans and pumps, and 2) the costs for the base plant fuel and gas turbine fuel attributable to operating with the dry loop. The design giving the minimum incremental cost is selected by the code.

3.3 PLANT DESCRIPTION

Heat rejection systems were designed for wet/dry allocations of 9, 20, 31 and 100% wet. The 100% wet design did not use the BNWGeo code, as only a wet system had to be designed. These heat rejection systems were designed for a plant modeled after the Holt/Procon design for the Heber site. The pertinent characteristics of this plant are listed in Table 3.2. Inputs to BNWGeo (Table 3.3) were prepared from information provided by EPRI(1978) and received from Holt/Procon via telephone. No attempt was made to model the geothermal plant directly. This was accomplished by using heat-rate/turbine exhaust temperature information supplied by Holt/Procon. The BNWGeo code treats the power plant as having a heat input, which is either converted to electricity or is rejected via the heat rejection system. The Holt/Procon geothermal plant had about 7 MWe of hydrocarbon pump energy, of which about 80% was transferred back into the plant's working fluid. The 0.1293 efficiency was chosen because it gives the correct heat rejection duty at the design point of the Holt/Procon design; the relatively small change in geothermal heat input was corrected for by adjusting the cost of hydrothermal energy. The 0.75 capacity factor and 0.21 fixed charge rate were selected as being consistent with geothermal plant operating procedures and with the capital portion of the cost of electricity given in EPRI (1978). The \$344 \$/KW refers to the cost of the geothermal plant exclusive of heat rejection components (the evaporative cooling system was taken to be 30% of the total plant cost from Holt/Procon data). Gas turbine capital and power costs were taken from EPRI (1979) and Monthly Energy Review (1977). All costs were converted to January 1976 dollars to be consistent with the BNWGeo code's cost algorithms.

The characteristics of the three wet/dry rejection systems studied are presented in Tables 3.4 through 3.7. Table 3.4 gives information on the heat rejection system. Tables 3.5 through 3.7 give information on the operating conditions for each of the three water allocations. The Heber meteorology was

TABLE 3.2. Holt/Procon Binary Plant Design

Location: Heber, California
Type: Binary - Supercritical Cycle
Brine Temperature - 360°F
Geothermal Heat Input: 1420.8×10^6 Btu/hr
Power:
 Gross 61 MWe
 Net 50 MWe
Working Fluid: 80% isobutane - 20% isopentane
Cooling System Parameters:
 Design Wet Bulb 80°F
 Condenser Log Mean Temperature
 Difference 12.7°F
Cooling Tower Approach 10°F
Cooling Water Range 18.2°F
Calculated Working Fluid Heat
 Rejection Temperature 114.0°F
Cooling Tower Duty 1233.3×10^6 Btu/hr
Land Requirements (excluding wells): 500 ft x 500 ft

TABLE 3.3. Selected BNWGeo Inputs

Net Power	50.0 MWe
Capacity Factor	0.75
Fixed Charge Rate	0.21
Hydrothermal Energy	58.2 ¢/mm Btu
Base Plant Capital	\$344/kW
Gas Turbine Capital	\$156/kW
Power Cost for Gas Turbines	29.47 mills/kWh
NH ₃ Vapor Velocity	150 ft/sec
NH ₃ Liquid Velocity	11 ft/sec
Design Temperature	32°F
Thermal Efficiency	0.1293

TABLE 3.4. Wet/Dry Heat Rejection Systems

	% Wet/dry		
	9	20	31
<u>Condenser - Reboiler</u>			
TTD - °F	14.0	13.2	14.0
Heat Transfer area, 10 ⁵ ft ²	2.1	2.2	2.1
Tube length - ft	30	30	30
Total number of tubes	26,700	27,800	26,600
Number of shells	9	9	9
Diameter of shells - in.	96	98	96
NH ₃ flow rate - 10 ⁶ lb/hr (all dry - 32°F)	1.9	1.9	1.9
<u>Dry Cooling Tower</u>			
Length - ft	675	526	526
Width - ft	121	121	121
Height to base of bundles - ft	36	34	34
No. of 28-ft diameter fans	52	41	41
Frontal area - 10 ³ ft ²	75.9	59.0	59.0
Heat transfer area - 10 ⁶ ft ²	5.8	4.6	4.5
Tube length - ft	50	50	50
Heat exchanger depth - in.	4.5	4.5	4.5
Air flowrate - 10 ⁶ lb/hr	199	137	137
Face velocity - ft/sec	8	8	8
Auxiliary power - MWe			
Fans	1.56	1.20	1.24
Pump	.06	.07	0.08
<u>Wet Cooling Tower</u>			
Tower units(a)	47,500	84,200	119,200
Maximum Duty - 10 ⁶ Btu-hr	1005	865	712
Range - °F	18	18	18
Approach - °F	16	10.8	9.1
Size(a)			
Length - ft	100	180	250
Width - ft	50	50	50
Auxiliary Power - MWe	1.8	2.4	3.2
<u>Water-Cooled Condenser</u>			
Range - °F	18	18	18
TTD - °F	16	14	16

(a) Tower units is a measure of tower size used by the Marley Co. in the design and costing of evaporative cooling towers. The all-wet cooling system uses 131,920 tower units, which is equivalent to a set of cooling towers 50ft x 280ft x ft (high). The cost and size of the wet towers for a wet-dry system, relative to the all-wet system, is the ratio of the number of tower units for each system.

TABLE 3.5. Operating Parameters for Wet/Dry Plant--215 Acre-Feet (9% wet)

Meteorological Interval	Corresponding Dry Bulb (°F)	Wet Bulb (°F)	Fraction of Year	Turbine Outlet Temp.(°F)	Turbine Back Pressure(psi)	Net Power Generated (MWe)	Heat Rejected (10 ⁹ Btu/hr)	Percentage of Heat Rejected by Wet Cooling Tower
1	114	80	0.019	130.0	109.7	36.9	1.048	68
2	106	78	0.025	130.0	109.7	36.9	1.048	52
3	102	76	0.033	130.0	109.7	36.9	1.048	44
4	99	74	0.031	130.0	109.7	36.9	1.048	38
5	97	72	0.031	130.0	109.7	36.9	1.048	34
6	93	70	0.076	130.0	109.7	36.9	1.048	26
7	91	65	0.075	130.0	109.7	36.9	1.048	22
8	81	65	0.072	130.0	109.7	36.9	1.048	1
9	78	60	0.137	127.5	106.1	38.0	1.045	--
10	77	55	0.083	126.5	104.7	38.4	1.043	--
11	65	55	0.117	114.1	88.2	43.1	1.027	--
12	61	50	0.112	110.0	83.3	44.4	1.023	--
13	53	45	0.115	101.9	74.1	46.9	1.014	--
14	46	40	0.043	95.0	66.8	48.8	1.008	--
15	41	35	0.025	90.1	62.0	50.0	1.004	--
16	32	30	0.001	81.4	54.2	51.8	0.998	--

TABLE 3.6. Operating Parameters for Wet/Dry Plant--475 Acre-Feet (20% Wet)

Meteorological Interval	Corresponding Dry Bulb (°F)	Wet Bulb (°F)	Fraction of Year	Turbine Outlet Temp.(°F)	Turbine Back Pressure(psi)	Net Power Generated (MWe)	Heat Rejected (10 ⁹ Btu/hr)	Percentage of Heat Rejected by Wet Cooling Tower
1	114	80	0.019	122.8	99.5	39.5	1.022	85
2	106	78	0.025	122.8	99.5	39.5	1.022	71
3	102	76	0.033	122.8	99.5	39.5	1.022	64
4	99	74	0.031	122.8	99.5	39.5	1.022	58
5	97	72	0.031	122.8	99.5	39.5	1.022	55
6	93	70	0.076	122.8	99.5	39.5	1.022	49
7	91	65	0.075	122.8	99.5	39.5	1.022	45
8	81	65	0.072	122.8	99.5	39.5	1.022	27
9	78	60	0.137	122.8	99.5	39.5	1.022	22
10	77	55	0.083	122.8	99.5	39.5	1.022	20
11	65	55	0.117	121.7	98.0	39.9	1.021	--
12	61	50	0.112	117.5	92.5	41.5	1.016	--
13	53	45	0.115	109.2	82.3	44.3	1.006	--
14	46	40	0.043	102.0	74.2	46.5	0.999	--
15	41	35	0.025	96.9	68.8	47.8	0.994	--
16	32	30	0.001	87.9	60.0	50.0	0.987	--

TABLE 3.7. Operating Parameters for Wet/Dry Plant--710 Acre-Feet (31% Wet)

Meteorological Interval	Corresponding Dry Bulb (°F)	Wet Bulb (°F)	Fraction of Year	Turbine Outlet Temp.(°F)	Turbine Back Pressure(psi)	Net Power Generated (MWe)	Heat Rejected (10 ⁹ Btu/hr)	Percentage of Heat Rejected by Wet Cooling Tower
1	114	80	0.019	115.1	89.4	42.5	1.017	99
2	106	78	0.025	115.1	89.4	42.5	1.017	84
3	102	76	0.033	115.1	89.4	42.5	1.017	77
4	99	74	0.031	115.1	89.4	42.5	1.017	73
5	97	72	0.031	115.1	89.4	42.5	1.017	69
6	93	70	0.076	115.1	89.4	42.5	1.017	62
7	91	65	0.075	115.1	89.4	42.5	1.017	60
8	81	65	0.072	115.1	89.4	42.5	1.017	42
9	78	60	0.137	115.1	89.4	42.5	1.017	36
10	77	55	0.083	115.1	89.4	42.5	1.017	35
11	65	55	0.117	115.1	89.4	42.5	1.017	13
12	61	50	0.112	115.1	89.4	42.5	1.017	6
13	53	45	0.115	110.2	83.5	44.2	1.012	--
14	46	40	0.043	103.0	75.3	46.4	1.004	--
15	41	35	0.025	98.0	69.9	47.8	0.999	--
16	32	30	0.001	88.9	61.0	50.0	0.992	--

simulated by dividing the year into 16 intervals, each with its corresponding wet and dry bulb temperatures. The turbine outlet temperature increased and net power generated decreased as the ambient temperature increased until wet augmentation began, at which point the turbine outlet temperature and the net power were held constant by increasing the percentage of heat rejected by the wet towers. As the water allocation increases, the fraction of the year that wet augmentation increased, the maximum percentage of the total heat rejected by the wet tower increased, and the optimal value of maximum turbine exhaust temperature decreased.

The heat rejected decreased only slightly with increasing water allocation, due to the lower heat rate at lower turbine exhaust temperature. With this in mind, Table 3.4 shows that condenser-reboiler TTD was nearly constant at 14°F. The optimal face velocity was 8 ft/sec in all cases, as was the depth of heat exchanger at 4.5 in. Heat transfer area was nearly identical for the scenarios with 15 and 23% normal water use and about 30% larger for the scenario with 7% normal water use.

The wet cooling tower size increased with increasing water allocation as indicated by the number of "tower units" required.^(a) An 18°F range gave near optimal results in all cases. The decrease in the number of tower units required was a result of the lower fraction of heat rejected during wet augmentation and, to a lesser extent, the larger approaches to the wet bulb. The all-wet plant required 11% more tower units than the 31% wet/dry power plant, partially because its power production on the "hot day" was 50 MWe compared to 42.5 MWe for the 31% power plants.

3.4 DISCUSSION OF WET/DRY SYSTEMS

The results are presented in a more concise form, along with estimated costs of electricity, in Table 3.8 for all wet/dry splits of 100, 31, 20, and 9%. The BNWGEO code optimizes the size of the geothermal plant, the wet/dry cooling system, and the gas turbine contingent to obtain the minimum cost of electricity. A similar optimization could have been done with the all-wet

(a) Tower units is a term used by the Marley Company to indicate the difficulty of the cooling task and the cost of the required cooling towers.

TABLE 3.8. Summary of Results

Amount of water evaporated per year - acre-feet	2310	710	475	215
Percentage of an all-wet plant's requirements	100	31	20	9
Gas turbine contingent - MWe	0	7.5	10.5	13.1
Maximum percentage of heat-removed by wet tower loop	100	99	85	68
Geothermal heat input - 10^6 Btu/hr	1233	1167	1162	1180
Turbine exhaust temperature during augmentation - $^{\circ}\text{F}$	N/A(a)	115.1	122.8	130.0
Ambient dry bulb temperature at which wet augmentation started - $^{\circ}\text{F}$	N/A	61	77	81
Fraction of the year augmentation used	N/A	0.81	0.58	0.36
Cost of electricity (mills/kWh)				
Base Plant(b)	26.4	26.4	26.4	26.4
Dry cooling loop capital costs	--	8.4	8.6	9.7
Wet cooling loop capital costs	5.0	3.7	2.5	1.8
Penalties	2.2	4.5	5.2	5.4
Total (mills/kWh)	33.6	43.0	42.7	43.3

(a) Peak Turbine exhaust temperature = 114°F

(b) Excluding heat rejection system and penalties

case, but the reduction in electricity cost would have been small; the geothermal plant output does not change radically over the annual temperature swings because of the relatively small changes in wet bulb temperature compared to the change in dry bulb temperatures. Even with a wet/dry plant, changes in BNWGE0 code input to force smaller gas turbine contingents had a relatively small effect on the incremental cost of dry cooling, as shown in Table 3.9, despite the high cost of dry cooling towers and the very hot climate found at Heber. Wet cooling would show a much smaller effect.

The decrease in maximum percentage of heat removed by the wet loop with decreasing water allocation has been discussed before. The geothermal heat input is very nearly constant for the three wet/dry cases; the larger value for

TABLE 3.9 Sensitivity of BNWGeo Incremental Cost
to Size of Gas Turbine Contingent

Wet-Dry Split %	Size of Gas Turbine Contingent (MWe)	Incremental Cost (mills/kWh)
31	7.5	10.6
31	6.0	11.1
31	5.1	11.4
31	3.8	11.9
20	10.5	12.3
20	9.0	12.5
20	7.8	13.0
20	6.5	13.3
9	13.0	14.1
9	12.1	14.7
9	10.4	15.0

the 100% wet plant stems from the absence of a gas turbine complement. Wet augmentation started at a lower ambient temperature and occupied a larger fraction of the year as the water allocation increased.

The cost of electricity for the four cases studied is presented in Table 3.10. The base plant cost is the same for all four cases and represents the cost of producing electricity from an idealized power plant with the same operating characteristics of the 100% wet plant but furnished with a zero cost heat rejection system that requires no auxiliary power. This cost (26.4 mills/kWh) is constant for all dry/wet splits. The dry cooling loop cost is the incremental cost attributable to the dry cooling tower loop, as calculated by BNWGeo. The cost of the wet cooling loop is the third contribution to the cost of electricity. The wet cooling loop cost includes the capital cost of the wet cooling tower loop plus the cost of providing auxiliary power for the evaporative cooling system.

As expected, the cost of the dry cooling tower loop increases with decreasing water allocation. Conversely, the cost of the wet cooling loop decreases with decreasing water allocation because of the smaller heat rejection duty required and, to a lesser extent, the smaller fraction of the year that the wet towers operate. As a result, the cost of electricity is essentially independent of water allocation between the 9% and 31% studied. It is not known whether the apparent minimum of 42.7 mills/kWh at 20% wet may be a

TABLE 3.10. Relative Costs of Electricity

Percent of 100% wet plants water requirements	100	31	20	9
Ratio of cost of electricity to that of 100% wet plant (this study)	1.00	1.28	1.27	1.28
Ratio of cost of electricity to that of 100% wet plant (R. W. Beck study - binary plant)	1.00	1.30	1.36	1.62(a)
Ratio of cost of electricity to that of 100% wet plant (UE&C study - flashed steam plant)	1.00	1.41	1.48	1.55

(a) extrapolated from 12%

true minimum or may be the result of limitations of the costing algorithms. However, it seems safe to say that there is very little change in the cost of electricity between 9% and 31% wet for the ammonia system.

Unfortunately, only one other study (Mitchell, Horsak, and Porter 1978) examined the cost of the direct-cooled geothermal heat rejection system. They reported that it was less expensive than the indirect system but have no design information. United Engineers & Constructors also studied the economics of flashed steam plants with wet/dry cooling systems (1977), but again, no plant design information was given.

Table 3.10 presents the ratio of the cost of electricity to that of a 100% wet-cooled plant is given for this study, the R. W. Beck study, and UE&C study. In all cases the normalizing cost was that of an all-wet plant of that particular study. All data are for the Heber site. Comparison with the R. W. Beck study is the most meaningful as they studied a binary plant with a direct cooling system. R. W. Beck chose the direct system, because they found that busbar electrical costs were a few percent lower at the hot Heber site climate. Presumably, the cost differential between the direct and indirect systems decreases and maybe reverses at cooler sites. Although the UE&C study was for a flashed steam system, the results are of use for comparison because an indirect system was used.

The cost ratios given in Table 3.10 were used to compute the percentage differences between the busbar cost of electricity for a binary plant equipped with an ammonia heat rejection system and that of 1) a binary plant equipped with a direct heat rejection system and 2) a flashed steam plant equipped with an indirect heat rejection system (Table 3.11). Electrical costs with the ammonia system were significantly smaller than that of the direct cooled binary plant for water allocations of 20% and 9% and significantly smaller (10 to 21%) than that of the flashed steam system at all three water allocations studied. The essentially constant cost penalty associated with the use of the ammonia heat rejection system between the 9 and 31% water allocations studied clearly stands out. Putting it another way, it appears to be possible to produce electricity from a binary geothermal plant as cheaply with a water allocation of 10% if an ammonia heat rejection system is used as it does with a water allocation of 30% if a direct heat rejection system is used. Or, alternately, ten times the geothermal power can be produced for a given amount of water, if a 28% increase in the cost of electricity can be tolerated. The relative cost penalties will be markedly less if the costs of acquiring water and disposing of blowdown are taken into account.

TABLE 3.11. Percentage Difference in Electrical Costs Compared to a Binary Plant with an Ammonia Cooling System

Percent Wet/Dry	31	20	9
Binary - Direct Heat Rejection System	2	7	27
Flashed Steam - Indirect Heat Rejection System	10	17	21

It is concluded that the ammonia system warrants further study. Therefore, it is recommended that a more detailed design study be made of this system. Furthermore, because of the lack of suitable wet/dry designs for comparison, it is recommended that optimal designs be made for at least one and preferably both of the "state-of-the-art" wet/dry heat rejection systems (both direct and indirect) for binary geothermal plants. These designs should then be costed on a comparable basis so that meaningful economic comparisons among the three systems can be made.

Ammonia has been investigated as a geothermal working fluid. Presumably its cycle efficiency in geothermal plants makes it noncompetitive at the Heber site, at least when water is available for cooling. But suppose ammonia were competitive with wet/dry cooling. That is, suppose the added cost of the base plant and the geothermal energy required for a binary plant using an ammonia working fluid were less than the considerable savings in the heat rejection system that would result. Then the best cooling system would be the direct system. The savings in the heat rejection system would be considerable, as one would have the advantages of both the direct system with its high temperature driving force and the ammonia system with its low piping and auxiliary power costs. Furthermore, the cost of the wet loop would be significantly smaller because the better heat transfer performance of ammonia would reduce the cost of the water-cooled condenser and the size of the wet tower required (because of lower condenser TTD).

We are not prepared to recommend here that ammonia be used as a working fluid for wet/dry cooled binary plants, but rather that a cycle analysis be made, to determine whether working fluids exist that would provide cheaper electricity for wet/dry systems than the hydrocarbons, which appear to be optimal for 100% wet systems. Because this was beyond the scope of this study we have no information on this matter at this time.

4.0. THE BINARY COOLING TOWER SYSTEM

Tower Systems Incorporated (TSI) has developed an advanced cooling tower system that can use low quality water for cooling while simultaneously producing much less blowdown than do conventional all-wet cooling systems. The BCT system was demonstrated at the Nevada Power Company Sunrise Station at Las Vegas, Nevada in 1979 (Slate, Zeien, and Sanderson 1980). In that application, the BCT system was operated in tandem with conventional wet towers to reduce the volume of the blowdown by a factor of 20. It was reported that the BCT system operated successfully without experiencing any serious problems with corrosion, scaling, or fouling in spite of producing a blowdown with an extremely high salt content (104,000 ppm TDS).

The BCT system is considered proprietary by TSI. Therefore, an agreement was reached among TSI, DOE, and PNL to furnish PNL sufficient information to permit performance and economic evaluation of the BCT system at the preconceptual level while protecting TSI from unauthorized publication of proprietary information. The level of detail furnished in this report reflects this agreement.

Successful operation of the BCT system would make it possible to use low quality water (e.g., agricultural waste water, brackish groundwater) to cool geothermal plants. The effluents from cooling towers using such low quality water would very likely require controlled disposal under regulatory rules such as those arising from the RCRA Act of 1976. One of the most promising disposal schemes is onsite evaporation in solar ponds. The ability of the BCT system to reduce the volume of the blowdown by a factor of 10 to 20 below that of a conventional wet tower greatly reduces the cost of such disposal and is the primary cost savings of the BCT system.

The application selected for evaluating the BCT system was the use of agricultural waste water from the New River, located in the Imperial Valley, California, to cool the 50-MWe binary geothermal plant described in Section 3. The blowdown was disposed of in an on-site solar pond.

4.1 SYSTEM DESCRIPTION

An artist's rendition of a BCT system tower is shown in Figure 4.1. The tower is equipped with 15 modules on each side for a total of 30 modules. The modules consist of a number of rectangular heat transfer panels; the sides are of polyester sheets, which provide the heat transfer surface, shown in Figure 4.2. The plant water to be cooled enters at the top of the panels and flows down the inside of the polyester sheets. Crossflow of air (relative to plant water) is induced by the fans. When operated in this manner the BCT tower functions as a dry, air-cooled heat exchanger. Wet operation is achieved by pumping a secondary water stream over the outside of the panels, Figures 4.2 and 4.3. Cooling is then obtained by evaporation of this water to the air. In the application studied here, the source of this secondary water is the New River.

The BCT system permits the use of low quality water because of two characteristics. First, the primary coolant system is isolated by the polyester film and by appropriate seals and basin design from the secondary fluid used for evaporative cooling. Therefore, condenser and piping corrosion and scaling problems are avoided. Second, the BCT tower can operate at extremely high salt concentrations (up to 120,000 ppm TDS) because of its configuration, choice of design materials, thermal environment, and water treatment.

4.2 PLANT DESCRIPTION

The BCT cooling system was designed for the binary geothermal plant studied in Section 3 using the same design bases. The condenser design and flow rate are essentially identical to the all-wet case given in Section 3. Thus, the BCT system cooling loop differs only in that a BCT tower with its secondary water loop was substituted for the conventional wet tower. Penalties were assessed for the 4.4 MWe of auxiliary power required by the BCT system rather than the 3.6 MWe for the conventional tower. In addition, a design point of 65°F wet bulb was selected for the BCT system rather than the 80°F wet bulb used for the conventional system. The resulting cooling loop may not be optimal.

The BCT tower, 52 ft wide by 460 ft long, is divided into nine cells containing twelve heat transfer modules and equipped with a 28-ft fan.

FIGURE 4.1. Binary Cooling Tower System Tower Showing Module Location

FIGURE 4.2. Binary Cooling Tower Module Detail

FIGURE 4.3. Secondary Water Circulation System

Figure 4.4 presents a flow diagram. The flow rate through the condenser loop is 137,300 gpm. The maximum flow rate of the secondary steam is 51,000 gpm. The secondary water loop of the BCT tower is designed to operate at 120,000 ppm TDS.

Water treatment is required on the secondary loop of the Binary Cooling Tower. The appropriate (lowest cost) water treatment approach for New River water (composition given in Table 4.1) is a combined front-end side-steam system. Makeup water must be appropriately treated to remove hardness, biological activity, and suspended solids. A small side stream from the secondary loop (Figure 4.4) is recycled through the treatment system to allow 24 cycles of concentration to be reached without exceeding scaling thresholds. The ratio of front-end to side-stream flow is about 20:1. A clarifier is used in a physical-chemical treatment mode. Lime and soda ash are added to remove calcium, magnesium, silica, and carbonate. Sufficient floc is generated to entrap the suspended solids containing the bulk of the bioactivity. The treated water is neutralized with acid.

Additional control of fouling and scaling is maintained in the secondary loop through addition of biocides, such as chlorine, and scale inhibitors. The pH and carbonate buildup are controlled through acid addition.

FIGURE 4.4. Flow Diagram--BCT System Using Agricultural Waste Water

TABLE 4.1. New River Water Composition

Water Quality Indicator	Heber ^(a)
20°C BOD ₅ (mg/l)	960
Suspended solids (mg/l)	743
Temperature (°F)	52-92
pH	7.0-8.0
Electrical conductivity (x10 ⁶) (microhms)	8931
Total dissolved solids (mg/l)	6060
Coliform (MPN/ml)	620,000
Total hardness (mg/l)	1255
Noncarbonate hardness (mg/l)	1017
Dissolved oxygen (mg/l)	8.6
Turbidity (mg/l)	280
Boron (mg/l)	2.55
Calcium (mg/l)	266
Magnesium (mg/l)	145
Sodium (mg/l)	1500
Potassium (mg/l)	--
Chloride (mg/l)	2600
Sulfate (mg/l)	876
Nitrate (mg/l)	31
Bicarbonate (mg/l)	370
Fluoride (mg/l)	1.8
Sodium (percent)	72

(a) New River at International Boundary

The closed primary cooling loop will require some chemical treatment such as pH control biocides and scale inhibitors. The loop would be purged occasionally to remove the buildup of impurities.

Of the 2450 acre-feet of New River water used per year, 2350 are evaporated and only 100 acre-feet require disposal.

The plant operating conditions are given in Table 4.2. The system operates in the all-wet mode above the 65°F wet bulb/81°F dry bulb. Net power falls off with increasing ambient temperature; the deficit is made up by gas turbines, which provide a maximum of 6 MWe on the hottest day. Below a dry bulb temperature of 90°F, the BCT tower operates in a wet/dry mode, reaching a low of only 29% wet at 32°F. This wet/dry operation is achieved by turning off the flow of secondary water to an increasing number of modules as the ambient temperature decreases. In this manner the BCT system should use about 20% less water than a 100% wet system for the same turbine back pressure-ambient temperature operating line.

TABLE 4.2. Binary Cooling Tower System Operation

Interval	Fraction of Year	Dry Bulb Temp. (°F)	Wet Bulb Temp. (°F)	Turbine Outlet Temp. (°F)	Turbine Back Pressure (psia)	Fraction Wet Operation	Net Power Output (MWe)	Gross Power Output (MWe)
1	0.019	114	80	125.9	104	1.000	44.0	48.5
2	0.025	106	78	120.5	96	1.000	46.6	51.0
3	0.033	102	76	120.1	96	1.000	46.9	51.3
4	0.031	99	74	119.1	95	1.000	47.3	51.7
5	0.031	97	72	117.6	93	1.000	48.0	52.4
6	0.076	93	70	116.1	91	1.000	48.7	53.1
7	0.075	91	65	114.0	88	1.000	50	54.4
8	0.072	81	65	114.0	88	0.942	50	54.4
9	0.137	78	60	114.0	88	0.851	50.1	54.4
10	0.083	77	55	114.0	88	0.785	50.1	54.4
11	0.117	65	55	114.0	88	0.737	50.1	54.4
12	0.112	61	50	114.0	88	0.674	50.2	54.4
13	0.115	53	45	114.0	88	0.565	50.2	54.4
14	0.043	46	40	114.0	88	0.481	50.3	54.4
15	0.025	41	35	114.0	88	0.4	50.3	54.4
16	0.001	32	30	114.0	88	0.288	50.4	54.4

4.3 PERFORMANCE AND ECONOMIC EVALUATION

The purpose of the performance evaluation was to determine whether the BCT tower would reject the required amount of heat using the auxiliary power available. The analysis was done in the absence of experimental data.

The thermal hydraulics of the BCT tower are fairly complex, because two water streams with different entering and exiting temperatures are involved. A further complicating feature is that the towers are of crossflow design. However, it was possible to obtain a satisfactory computation of BCT system tower performance by using the theory of deluged heat exchangers developed by PNL (Braun et al. 1978; Parry et al. 1979).

The deluge heat exchanger theory takes into account the heat transfer resistances in the two liquid streams and the combined heat and mass transfer at the air-water interface. Heat and mass transfer across the air-water interface was found to be the controlling resistance. As suggested by TSI, the Gilliland-Sherwood equation^(a) (Perry 1973) was used to determine the mass transfer coefficients. This was used in conjunction with an enthalpy driving force to determine the total heat transfer across the air-water interface. It was concluded that the BCT has sufficient surface area providing that fouling coefficients are not large and assuming that the polyester sheet is well wetted by both the primary and secondary streams. The design used by TSI to accomplish complete wetting of the thin film on the secondary-stream side and high heat transfer coefficients on the primary-stream side are the principal proprietary aspects of the BCT technology. PNL has not had the opportunity to witness these features. However, from the description provided by TSI (under the confidentiality agreement) the performance claimed with respect to these features appears to be reasonable. The effects of uncertainties in the magnitude of the heat transfer resistances in the system were investigated by

(a) PNL has not had an opportunity to review the TSI data to determine the applicability of the Gilliland-Sherwood equation to the BCT tower. This correlation is essentially the well-accepted McAdams' equation for turbulent-flow heat transfer in pipes extended to mass transfer, using the Chilton-Colburn analogy of mass transfer to heat transfer for turbulent flow. It has been confirmed for mass transfer in wetted wall columns.

determining the impact of reduced coefficients. It was concluded that the tower should still perform adequately with modest reductions in air-side heat and mass transfer coefficients or with substantial reductions in water-side heat transfer coefficients.

Checks on the auxiliary power requirements indicate that fan and pump powers assigned to the system were adequate. The effects of wave action on the secondary water film were simulated by applying friction factors equivalent to very large surface roughness to equivalent diameter ratios.

Determining whether the BCT system can operate over the life of a geothermal power plant without suffering unacceptably from corrosion, scaling, or fouling was beyond the scope of this study. Information from the Sunrise Station test (Slate, Zeien, and Lancaster 1980) indicated that no major problems of this type had arisen. However, no detailed study of the chemistry of the New River water vis-a-vis that of the Sunrise Station waste stream was made to ensure that the results from the Sunrise Station test, with respect to the avoidance of scaling and corrosion, could be extrapolated to the situation at Heber. Because the BCT makes substantial use of plastics, the problem of life expectancy was investigated by assuming that the modules had a 5-yr life expectancy. This is probably a pessimistic assumption based on TSI's statements about their test experience and on the nature of the materials used. The cost of replacing the modules every 5 years does not greatly affect the competitiveness of the BCT system, as will be shown in Section 4.4, if no reliability problem reduces power plant availability.

The economic evaluation consisted of making preconceptual cost analyses of the tower and placing these on the same basis used to compute system costs in Section 3. The PNL estimate of the BCT tower cost (the only component that differs from the all-wet plant design in Section 3) was 2 to 19% greater than the TSI estimate. This is in very good agreement for a preconceptual costing effort.

4.4 BUSBAR ELECTRICAL COST COMPARISON

The competitiveness of the BCT system was determined by computing the busbar cost of electricity from a 50-MWe binary geothermal power plant using New

River water for cooling and operating in a zero discharge mode by using on-site solar ponds. Three systems were costed: the BCT system, the 9% wet/dry NH_3 system, and the conventional all-wet system. The water requirements and waste disposal requirements of the three systems are given in Table 4.3; the cost of electricity is given in Table 4.4.

The BCT system used about 40% less water than the conventional system, primarily because of its much lower blowdown. The 9% wet/dry NH_3 system used the least water of all; it was selected because of the lower waste treatment costs and because the NH_3 system's busbar electrical costs are essentially constant between 9 and 30% wet/dry (Table 3.8)

TABLE 4.3. Water and Waste Disposal Requirements of Three Systems Using Agricultural Waste Water (5000 ppm TDS)

	<u>Conventional Evaporative Cooling System</u>	<u>BCT Cooling System</u>	<u>9% Wet/Dry NH_3 System</u>
Annual Water consumption acre-ft	3471	2450	312
Concentration cycles and limiting factor	3 (chloride corrosion)	24 (evaporation rate in secondary loop)	3 (chloride corrosion)
Annual waste water generated (blowdown) acre-ft	1158	100	104
Solar pond size acres	312	27	28

TABLE 4.4. Cost of Electricity Using Agricultural Waste Water and Zero Discharge

	<u>Conventional Wet Tower</u>	<u>BCT Tower</u>	<u>9% Wet/Dry NH₃</u>
Base Plant	26.4(a)	26.4(a)	26.4(a)
Wet cooling loop Capital costs	5.0(a)	6.6-7.1	1.8(a)
Dry cooling loop Capital costs	---	---	9.7(a)
Cooling system penalties	2.2	3.5	5.4
Water treatment	0.6	0.5-0.8	0.3
Waste disposal ^(b)	<u>9.1</u>	<u>0.8</u>	<u>0.8</u>
	43.3	37.8-38.6	44.4

(a) Taken from Table 3.8.

(b) Solar ponds at \$60,000/acre.

The conventional system requires 312 acres of solar ponds for waste disposal, whereas the other two systems require a little under 30 acres. This difference in solar pond requirements has a large effect on electrical costs as shown on Table 4.4 where it is shown that waste disposal amounts to 9.1 mills/kWh for the conventional system versus 0.8 mills/kWh for the other two systems. Largely because of this factor, the BCT system gives the lowest electrical cost (near 38 mills/kWh), which is only 13% above that of a conventional wet system using high quality water and is 14% less than either the conventional system or the 9% wet/dry ammonia system when waste water is used.

The assumption of the need for on-site ponds was made in the absence of definite information that other modes of disposal of the tower blowdown would be allowed. ReInjection of this waste stream into the geothermal field has been proposed but its technical feasibility or political acceptability have not been established. The costs indicated in Tables 4.3 and 4.4 represent an expensive but feasible approach and can be considered a near upper bound for

this aspect of waste heat rejection systems. The cost of waste water reinjection has not been evaluated. It would not be trivial because of the need for removal of all suspended solids and chemical adjustment to reduce the probability of plugging the disposal well. The capital investment in the wells themselves might be a significant factor.

The 37.8 to 38.6 mills/kWh range given for the BCT system in Table 4.4 reflects the cost spreads found in the PNL cost estimates and thus gives some measure of the likely uncertainty in relative costs among the systems. Another means of obtaining a measure of the effects of cost uncertainties on the electrical costs is to compute the effect of doubling the cost of the BCT system tower. Because the capital cost of this tower constitutes only 40% of the cooling tower loop indicated in Table 4.4, doubling it increases the power cost by about 2.4 mills/kWh. Also, if the plastic components required replacement every 5 years (a method of inserting conservatism into operating life), the cost of electricity would rise by about 0.2 mills/kWh. Although it is difficult to predict the cost of systems that have not been built, it is not likely that the cost of the BCT tower would double relative to that of a conventional tower.

It is possible to give only a conditional endorsement of the BCT system in the absence of sufficient operating data to verify that the BCT tower does perform as claimed, because PNL does not know how closely the assumptions and correlations used in the technical evaluation are followed. However, if the assumptions used in performing the technical evaluation are indeed valid, it is concluded that the BCT system offers significant economic advantages when used with brackish or waste water. The BCT system makes possible the use of low quality water for geothermal power plants at a relatively modest economic penalty (especially considering that the alternative may be not developing the resource at all). Therefore, further studies are recommended. First, the performance of the TSI system must be verified by review of experimental and performance data. Second, a more detailed cost study should be made. Following this, a demonstration seems warranted to prove out the system's reliability and operating behavior over a time period of several years.

5.0 CONCLUDING COMMENTS

The potential cost benefits from applying two heat rejection advanced concepts to binary geothermal power plants were investigated. It appears that the wet/dry NH_3 system has promise of being significantly less costly than state-of-the-art wet/dry systems. The BCT system studied offers significant promise of making it possible to use low quality water for geothermal cooling at a cost penalty of about 15% or about half the penalty of the wet/dry NH_3 system with high quality water. This development is particularly interesting because low quality water is available in many areas. Specifically, the Imperial Valley, one of the more promising undeveloped, water-short geothermal resources, has significant quantities of agricultural waste water which could be used for geothermal power plant cooling.

Thus, these two technologies could make possible development of geothermal resources that might be severely limited by the lack of available high quality water. Although the 29% cost addition required for dry/wet cooling and the 15% cost increase required for the BCT system appear large, it should be kept in mind that the true cost and, therefore, the overall economics of geothermal power will not be known until plants have been built and operated.

Hybrid schemes that combine conventional wet tower technology with the BCT system or the NH_3 wet/dry system with the BCT system have not been investigated here but warrant further study. The first approach, in which the BCT system tower is used to concentrate the effluent from conventional towers, might be cheaper with certain water chemistries than use of either a conventional or a BCT system tower alone. The second approach, in which BCT system is combined with an NH_3 system to form a wet/dry system that would conserve water while simultaneously permitting the use of brackish water, would have merit in regions such as the Imperial Valley, where even waste water may be of limited supply because of the desire to preserve the current salinity of the Salton Sea.

Tower Systems Incorporated has stated that their concept can be developed into a competitive wet/dry system. This idea warrants consideration for further study.

As mentioned in Section 3, identification of geothermal working fluids designed to maximize performance through both the Rankine cycle and the heat rejection system is warranted.

Geothermal areas are generally characterized by large diurnal temperature swings. Preliminary studies by PNL of a capacitive cooling scheme proposed by Chicago Bridge & Iron indicate that the system shows promise for fossil fuel plants. This system uses an all-dry ammonia heat rejection system combined with a heat-pump stored-fluid capacitive system that supplements heat rejection during the day and is cooled by dry cooling during the night. The CB&I system might provide economical dry cooling for those geothermal sites where no water is available.

The wet/dry NH_3 system offers sufficient promise to warrant further study. The Electric Power Research Institute is currently evaluating the relative merits of the methods of reducing the overall cost of using waste water for cooling power plants. If the BCT system continues to appear promising, further studies should be made of both the wet/dry NH_3 and the BCT system with the goal of demonstrating both systems. A detailed study of several geothermal sites, all having a probability of being developed within the next 10 to 15 years, should be made to determine which advanced concept is most applicable to each site. This study would firm up the need for such systems, provide the design basis for system studies, and lay the groundwork for the demonstrations.

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