Geothermal Resources Council, Monograph on The Geysers Geothermal Field, Special Report No. 17, 1991

POWER PLANT ALTERNATIVES FOR IMPROVING AND EXTENDING RESERVOIR PERFORMANCE AT THE GEYSERS

Murray S. Grande and Steven L. Enedy

Northern California Power Agency
P.O. Box 663, Middletown, California 95461

ABSTRACT

As a result of the higher than anticipated steam production decline rates experienced by Northern California Power Agency (NCPA) at The Geysers, instituted a feasibility study of the power plant alternatives for improving and extending reservoir performance. The study found that the most attractive alternatives for extending the geothermal project's performance were: (1) modification of the operations of the power plants to reduce average annual output while maintaining the ability to peak at full load, (2) reduction of plant inlet pressure by modifying gas ejector nozzle size and changing to a control valve wide-open operation, and (3) increase the amount of condensate available for reinjection with a dry cooling system. However, because of the high capital costs associated with dry cooling, additional reservoir and energy price studies are needed to better quantify the benefit of water injection.

INTRODUCTION

NCPA operates two geothermal power plants at The Geysers in Sonoma and Lake Counties, California. Each plant consists of two 55 MW (gross) (nameplate) double flow turbine generator units and all electrical, mechanical, transmission, and control facilities. Installed nameplate capacity for the two plants is 220 MW (gross); however, Plant #1 has been rerated at 122 MW (gross) and Plant #2 has been rerated at 124 MW (gross).

The steam supply area, which is also operated by NCPA, includes approximately 60 steam production wells and three condensate reinjection wells located on federal leases CA-949 and CA-950 near the southeastern edge of the field. Other related steam production facilities operated by NCPA include roughly 8.5 miles of steam gathering pipelines, a computer based automated Distributed Steam Control System, a condensate reinjection system, and a drill rig, capable of drilling makeup steam wells to depths in excess of 10,000 feet.

The steam field has historically maintained sufficient capacity to operate the power plants at full load owing in part to a successful makeup well drilling program (Smith, 1988; Yarter, Cavote and Quinn, this volume). However, the existing wells have experienced greater than anticipated declines in steam production since NCPA placed Plant #2 in full operation in May 1986. Through 1988, the steam production decline rates on the NCPA leases persisted at 25 to 28 percent per year compared to the previous (1983-1985) annualized exponential decline of 5 to 15 percent (Enedy, 1987).

As a result of the higher than anticipated decline rates, NCPA initiated a comprehensive reservoir management study which determined that the potential productive capacity of the geothermal steam reservoir is less than previously estimated. The studies are not complete and the agency is continuing an on-going program to monitor and manage its geothermal steam reservoir at an optimum long-term capacity and energy levels for its agency members. However, on the basis of preliminary results of the reservoir management study, NCPA instituted the following policies:

1. Modify the operations of the power plants to reduce average annual output while maintaining the ability to peak at full load whenever required by the agency members.
2. Analyze the cost effectiveness of alternatives for improving and extending reservoir performance, including supplemental water injection, plant equipment modification and changes in operating methodology which allows for lower pressure operations.

This paper details initial results of the base-line data gathering and plant performance studies necessary to analyze the cost effectiveness of the alternatives listed above.

LOAD FOLLOWING OPERATIONS

NCPA potentially benefits from load following in three ways: (1) steam is conserved for anticipated future high demand periods, (2) the operating flexibility for load following and peaking can be maintained for a longer time because decreased reservoir steam decline and higher absolute flow rates from the existing wells and (3) makeup well drilling necessary to maintain capacity can be deferred, which reduces near term costs.

The economic benefit obtained from steam conservation depends on the current cost of supplemental energy and capacity purchases compared to future costs. NCPA recently quantified the trade offs of reduced generation in the near term versus future reduced supplemental energy purchases and found that the net present value (NPV) of the steam field was maximized by reducing average annual load while maintaining the ability to peak at full capacity for an extended period (NCPA Status Report 1989). The NPV is based on a series of long-term forecasts of available power generation from the geothermal project at various operating scenarios. The forecasts include the anticipated results of the makeup well drilling program and the actual decline (reserves) calculated on the existing wells using the standard methods of decline curve analysis (Enedy, this volume).

The decision by NCPA to modify the basic operating philosophy of its geothermal plants from a base-loaded operation to a load- following/peaking operation necessitated the need for a detailed evaluation of plant steam efficiency as a function of load. A program was undertaken to conduct performance tests on the major components of each unit through the required load range.

The program schedule included full throttle performance tests of the turbines from 25 to 55 MW in increments of 5 MW. In addition, valves wide open tests were conducted at 50, 55, and 62 MW. The 62 MW test represented the peak capacity of the units. The valves wide open tests were conducted in order to compare turbine efficiencies at this condition with the valves throttled condition. A valves wide open test was also conducted at 55 MW with an artificially induced high condenser backpressure to help in validating the manufacturer's turbine performance correction curves. Finally, a repeat test was conducted at the rated load of 55 MW with valves wide open in order to measure the repeatability of the tests. The performance of the main condenser and cooling tower was also monitored during each of the turbine tests.

The results of the tests revealed significant increases in turbine steam rates as load was reduced. Figure 1 is a set of curves showing steam rate versus load for each of the four NCPA turbines. It can be seen that while the general shape of the curve is the same for each unit, there did exist a slight difference in turbine efficiency between the units. This information was used to minimize the steam rate penalty associated with low load operation. Unit performance test data were used to develop incremental steam rate curves as a function of ambient wet bulb temperatures. The incremental steam rate curves were then entered into a software program that provides the lowest collective steam rate for any given load combination of the units. This program is then used by the NCPA dispatch center during reduced load operations. The curves are updated with new turbine performance test results each time a test is conducted. Tests are conducted annually and following turbine overhauls.

In addition to incremental loading of the units, other means of improving turbine efficiency were explored. As previously mentioned, valves wide open tests were conducted on the turbines. Results of the tests found no reduction in net unit steam rate. Valves wide open, low pressure operation does, however, offer advantages from a steam reservoir point of view, as will be discussed later.

The fact that turbine performance at rated load of Units 1 and 2 was below the design steam rate and the performance of Units 3 and 4 was only slightly above the design steam rate suggested that there was no significant poten-

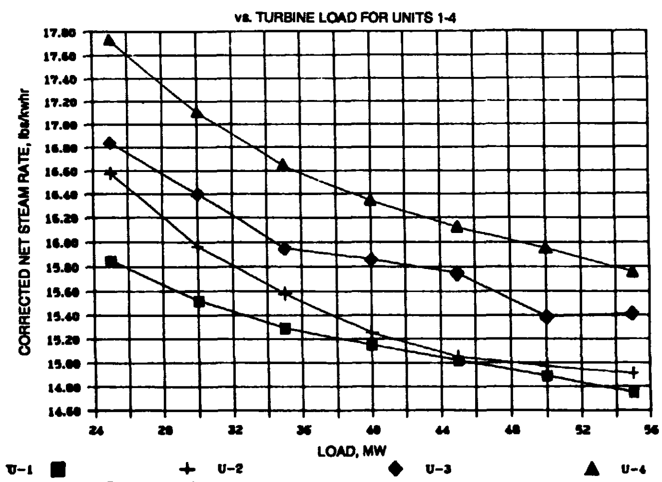

Figure 1. Corrected net steam rate.

tial for substantially reducing the unit steam rates through operational or maintenance practices. Likewise, the low available energy of geothermal steam (as compared to a modern fossil or nuclear Rankine cycle unit) does not provide much potential for cost effective retrofits on existing equipment.

In addition to increased steam rates, load following operation has resulted in another operational consideration, namely noncondensible gases. Throttling of steam wells during low load periods has resulted in a general increase in gas, including hydrogen sulfide. Gas concentrations are found to be particularly high following extended low load periods, such as over a weekend. This presents problems when trying to respond to weekday peaks. These high gas conditions have necessitated changes in operational procedures and hydrogen sulfide abatement optimization programs.

LOW PRESSURE OPERATION

The NCPA geothermal project benefits from low pressure operation in three ways: (1) an increase in steam deliverability which allows for higher peaking, (2) increased reserves and extended field life, and (3) increased utilization of low pressure wells.

An average increase of 26.2 percent in deliverability at 130 psig compared to 160 psig for wells completed on the NCPA steam field leases was observed during July 1988. Figure 2 contrasts the Inflow Performance Curves for wells F-5 (completed in a low pressure area) and P-5, (completed in a high pressure area). Well F-5's flow rate increases from 35 thousand lb/hr at 160 psig to 62 thousand lb/hr at 130 psig (+77.1 percent) compared to an increase from 89 to 92 thousand lb/hr (3.4 percent) for well P-5.

Higher flow rates at lower line pressures leads to the second benefit of low pressure operation: increased reserves and extended field life. Finally, low pressure operation allows for the utilization of the wells in the lowest pressure

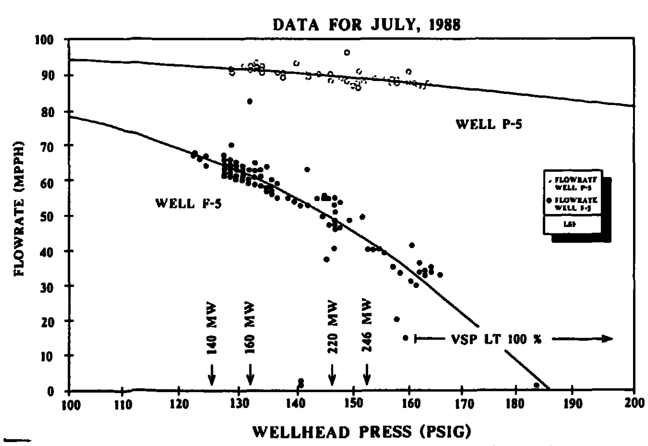

Figure 2. Inflow performance curves: Well P-5 (upper) and Well F-5 (lower).

areas of the field, which do not flow at high load, high pressure conditions.

The steam reservoir benefit of low pressure operation prompted NCPA to explore ways to incorporate low pressure into the power plant operation. Results of the turbine performance tests previously mentioned pointed out areas where low pressure operation could be taken advantage of with NCPA's load following schedule.

The turbine performance tests established which throttle pressures were necessary to maintain different loads on the units. Up to this point, low load was achieved by throttling the turbine control valve to the desired load point. This often resulted in significant pressure drops across the control valve. This pressure drop could be eliminated with valves wide open turbine operation, which would enable the steam field to operate at much lower pressures when load demand allowed it.

Several steps needed to be accomplished before low pressure operation was possible. The first step dealt with the main condenser noncondensible gas removal system. The steam driven gas ejectors required a minimum of 90 psig to operate. This requirement prevented operation below that pressure. A study was undertaken to determine the most cost effective way to eliminate this constraint. The study focused on replacement of the gas ejectors with vacuum pumps, lower pressure ejectors, or a combination of both.

Results of the study indicated that an all vacuum pump gas removal train was not economically feasible. The options were limited to low pressure first stage ejectors with second stage vacuum pumps or ejectors. Vacuum pumps represented a significantly higher capital investment with the advantages of reduced steam consumption. Low pressure ejectors resulted in slightly higher steam consumption. Ejector options included replacement of the nozzle only or both the nozzle and diffuser section, with steam consumption and cost as the evaluation parameters.

A nozzle only change out was attractive in the short term, since this option had a relatively low capital cost, involved no plant modifications, and could be accomplished in a short time. The disadvantage was increasing motive steam consumption for decreasing steam pressure; however, the steam usage increase associated with changing the ejectors to 50 psi motive steam pressure amounted to only 0.3 percent. It was decided to change the ejectors, nozzles to gain immediate benefit from low load/low pressure operation, and to delay any major vacuum pump modifications until further detailed economic studies could be conducted. The benefits of low pressure operation far outweighed the modest increase in steam consumption experienced with the low pressure ejectors.

An additional step needed to maximize the benefit of low pressure operation was to ensure that the turbines were capable of operating at low pressure whenever load levels permitted it. This entailed keeping the turbine stationary and the rotating blades free of deposits. In the past, NCPA turbines had experienced buildup of deposits on the first and second stage blades which resulted in higher inlet pressures to the turbines to maintain load. Continued buildup of deposits would reduce or eliminate low pressure operation. To eliminate deposits, NCPA installed a turbine wash on each of its turbines. Water is injected upstream of the turbine via a high pressure pump on an intermittent basis. The wash prevents any significant buildup of deposits and allows the turbines to operate at the lowest possible inlet pressure.

Finally, NCPA is exploring with the turbine manufacturers possible modifications to the turbines for permanent low pressure/reduced capacity operation. This possibility is being explored for the future steam reservoir low pressures that are predicted. Modifications may allow for more efficient use of the low pressure steam. To date no finalized recommendations have been made.

AUGMENTED INJECTION

NCPA potentially benefits from water injection in two ways: (1) increased field life by increasing the amount of recoverable reserves and (2) increased deliverability because of decreased pressure decline. Both of these benefits will occur only if the injected condensate flashes without a considerable cooling of the geothermal resource. Evidence obtained from tracer analysis indicated that the injected water is indeed boiling and augmenting the steam production. However, it has not been shown that the reservoir can increase or even continue to sustain the current boiling rates.

Beall, Enedy, and Box, this volume, showed that deuterium anomalies exist around the major injection wells within the NCPA leasehold. The magnitude of the deuterium shift indicated that the recovery of injected condensate as flashed steam ranges between 34 and 52 percent of the total condensate injected for all of the injectors in the southeastern Geysers. The combined injection-derived flow from the NCPA injectors was 307 thousand lb/hr, indicated by an October 1987 deuterium survey. Additional studies of the ability of the reservoir to sustain increased condensate injection are planned for an area near the C-Site in leasehold CA-950 (Kline and Enedy, this volume).

An empirical model was developed to help determine the cost effectiveness of any proposed cooling tower modification or fresh water development program. The model is based on known flow rate versus cumulative production relationships but includes assumed rates of boiling from tritium recovery tests conducted in injection wells Y-4 and Y-5 in 1987 and 1989. The model was later verified by numerical simulation (GeothermEx, 1989).

The 1991 power plant operation at NCPA results in 60 to 80 percent evaporation of the makeup condensate depending on the plant load and atmospheric conditions. A significant supply of steam reservoir injection water for the injection augmentation program could be provided if plant evaporation requirements were reduced.

Cooling tower evaporative loss is primarily a function of the unit load, ambient wet and dry bulb temperatures, the number of circulating water pumps in service, and the number of cooling tower fans in service. For a given average annual power generation, the annual evaporative losses could be reduced significantly, potentially by as much as 10 percent, if the unit loading patterns previously discussed were regulated strictly on the basis of minimizing evaporation. Unfortunately, the required loading patterns for minimum evaporation tend to be the exact opposite of the loading patterns required to meet power demands. The minimum evaporative losses occur when the air dry bulb temperature is coolest and the humidity is highest, i.e. at night when power demands are at their lowest. The maximum evaporative losses occur when the dry bulb temperature is highest and the humidity is lowest, i.e. during the afternoon of a hot summer day when annual power demand peaks. Since power demands must be met, there is minimal operational flexibility to significantly reduce evaporative losses through load control. This leaves plant equipment modifications as the only way to significantly reduce evaporation. The focus of plant modifications was on dry cooling.

Dry cooling systems reject heat to the atmosphere through sensible heat transfer, thus, evaporative losses do not occur during the cooling process. In evaporative cooling, heat transfer occurs with direct contact between the water and air, while in dry cooling, heat transfer between the water and air occurs across a heat transfer medium, such as metal tubes.

Since dry cooling uses sensible heat transfer, the sink temperature against which it operates is the ambient dry bulb temperature, rather than the wet bulb temperature. In addition, there is an additional temperature gradient across the heat transfer surface which separates the water and air. This is the major disadvantage which has prevented the widespread application of dry cooling. The higher sink temperature for dry cooling, as compared to evaporative cooling, results in a lower potential thermodynamic cycle efficiency.

There are a large number of dry cooling options available, however, due to the limited application of dry cooling, especially for large heat rejection duties; most of these options are either infeasible or there is limited or no application experience to date.

The scope of the NCPA study was limited to considering only conventional dry cooling system options, air cooled steam condensing and serial dry/wet cooling. Air cooled steam condensing condenses steam inside finned air cooled tubes. A portion of the exhaust steam from the turbine would be conveyed to a header system which ties together finned tube assemblies. Steam is condensed in the finned tubes and the condensate flows into lower sections where additional heat transfer can occur depending on the design and required approach to the dry bulb temperature. Air is commonly forced over the finned tubes via a series of fans located below the tube assemblies. Depending on the design optimization in terms of desired water savings, ambient dry and wet bulb temperature and condenser pressure, the air cooled condenser could operate alone, in parallel, or in series with the existing cooling towers.

Dry/wet cooling requires the installation of a sizable dry cooling system adjacent to or possibly above the existing evaporative cooling towers. Heated circulating water from the condenser would be pumped to the dry tower first, and then to the evaporative tower prior to returning it to the condenser. The extent to which the dry tower is utilized would again depend on the ambient wet and dry bulb temperatures, the plant heat load, the desired water conservation, etc.

A number of possible design options exist, even within the two systems described above; however, no attempt was made in this study to examine specific designs. Rather, as previously mentioned, the objective in examining the dry cooling alternatives in this study was to determine whether or not the economics of the alternatives merited an actual design effort. The study was based on reducing evaporative losses by one third. For NCPA Units 1 and 2, for example, this would represent a reduction in evaporative losses of approximately 500 gpm. For the purposes of the engineering estimate, it was assumed the four cooling towers serving the NCPA units were essentially identical in terms of expected heat load and evaporative losses.

The engineering estimate was based on using an air cooled condenser. A dry cooling tower could also provide the same design conditions, however, the dry tower would be required to cool the entire circulating water flow rate, whereas the air cooled condenser would only cool a portion of the steam exiting the turbine. As a result, it was estimated the dry cooling tower total construction costs would be 30 to 50 percent higher, the required physical size would be larger, and the power consumption greater than an air cooled condenser. An engineering estimate for an air cooled condenser was provided by GEA Power Systems and was based on a mean annual dry bulb temperature of 50°F and a heat load of 226 million BTUs/hour. A target value of 3.0 in. HgA condenser pressure and 115°F saturation temperature yield an initial temperature difference (ITD) in the condenser of 65 degrees at the mean ambient dry bulb temperature. It should be noted that this did not necessarily represent the optimum design, but was chosen on the basis of assumed size constraints. On this basis, the air cooled condenser design and associated cost estimates are provided in Figure 3.

AIR COOLED CONDENSER	
A. DESIGN OPERATING CONDITIONS	
Heat Load	266,000,000 BTU/hr
Condenser Pressure	3" Hg
Mean Ambient Dry-Bulb Temp	50°F
B. PHYSICAL CHARACTERISTICS OF DIRECT CONDENSER	
Length	120 ft.
Width	50 ft.
Height	30 ft.
C. HEAT EXCHANGER "A" FRAMES	
Number of "A" Frames	25
Material - carbon steel	
Piping & Condensing Surfaces	- stainless steel
D. FANS	
Number of Fans	10
Fan Diameter	20 ft.
CONDENSER COST ESTIMATES	
MATERIALS	
Includes stainless condensing surfaces, carbon steel finned tube heat exchangers, fans, support structure, piping, etc.	$4,500,000
Engineering & Construction	600,000
TOTAL PER UNIT	$5,100,000

Figure 3. Air cooled condenser.

The aforementioned design would provide condensing of the steam at 50°F ambient dry bulb with reduced heat load to the evaporative cooling towers. At higher dry bulb temperatures, say 90°F, the heat load that can be accommodated by the air cooled condenser is approximated by the ratio of the new ITD to the design ITD (i.e. (115-90)/(115-50)), or 38 percent. Similar approximations can be made for other desired condenser pressures. For example, the saturation temperature for a target condenser pressure of 2.0 in Hg is 101.1°F. Accordingly, the ITD is reduced by 14°F from the previously assumed design case of 3.0 in HgA.

Alternatively, if the desire is to minimize evaporation by holding the heat load to the condenser constant and allowing back pressure to rise, the ITD can be assumed to remain fairly constant over a wide range of ambient temperatures. For example, for a 65°F dry bulb, the steam saturation temperature for condensation of the 288 million BTU/Hr heat load would be 130°F (DBT + ITD = 65 + 65), which corresponds to a back pressure of 4.5 in. Hg.

A plant cycle computer model was developed to allow case by case studies to be conducted for different dry cooling options. The model calculates the unit steam flow, gross and net steam rate, and evaporation rate for any desired input condition. Figure 4 provides a schematic of the model inputs and outputs. The dry condenser is an optional input, depending on which case is being evaluated. The model is also capable of developing multiple cases. The model computes a value referred to as "net water rate". The net water rate is the quantity of the steam input minus the cooling tower blow-down (i.e. the reinjection rate), divided by the net power. The net water rate, therefore, provides a direct numerical benefit comparison between the dry cooling and non dry cooling options at various input conditions (i.e. load, dry and wet bulb temperatures). The plant cycle computer model was then incorporated into the previously mentioned empirical steam reserve model developed by the NCPA Production Department. This model was then used to conduct an economic feasibility study.

The model was run for two cases, with and without dry condensing. Unit 3 performance test data over the 25 to 55

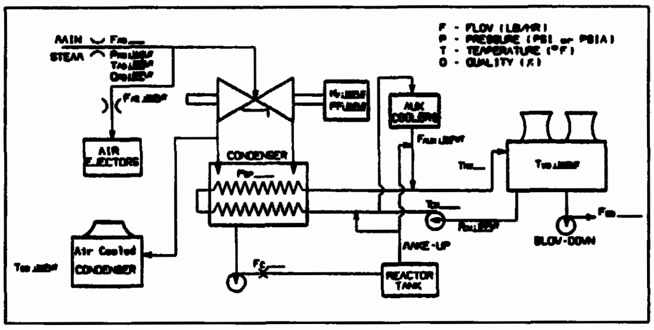

Figure 4. NCPA Unit 1-4 computer model.

MW load range was used for the model input, along with one year of monitoring data beginning in May 1987 from The Geysers Air Monitoring Program Unit 13 meteorological station. The average annual and peak generation values over time with and without air cooled condensing that were output from the model are shown in Figure 5. This output was then used to predict the annual energy and capacity savings realized from air cooled condensing. Figure 6 plots the savings with time. Based on these annual cost savings, net present values were computed for rate of return values between 4 and 16 percent as shown in Figure 7. The benefit-cost ratio was based on a total installed cost of $30,000,000 for air cooled condensers for all four units, and ranges from 6:1 for a 4 percent rate of return to a 1:1 at a 16 percent rate of return.

The economic evaluation indicated there is potential for benefit which can be achieved if the NCPA units are retrofitted with supplemental dry cooling systems. The nominal air cooled condenser design chosen for this study would provide an increase in the steam field reinjection rate of approximately 50 percent over the current rate. The accuracy of the economic evaluation is dependent on a number of factors. Although the results indicate there is a significant benefit to dry cooling, more empirical information needs to be acquired on some of the evaluation input parameters before a confident conclusion can be reached.

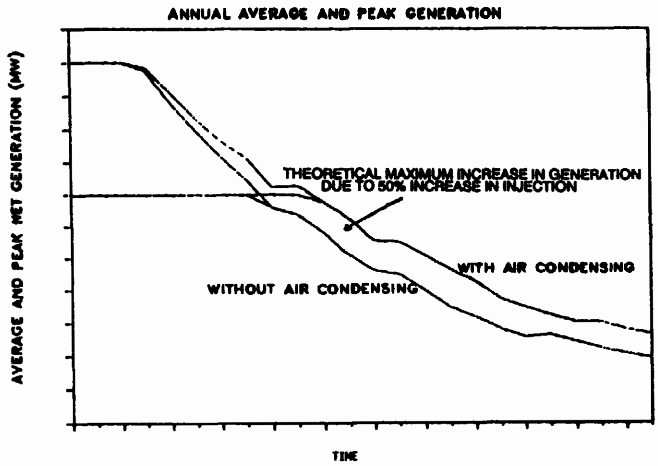

Figure 5. Annual average and peak generation.

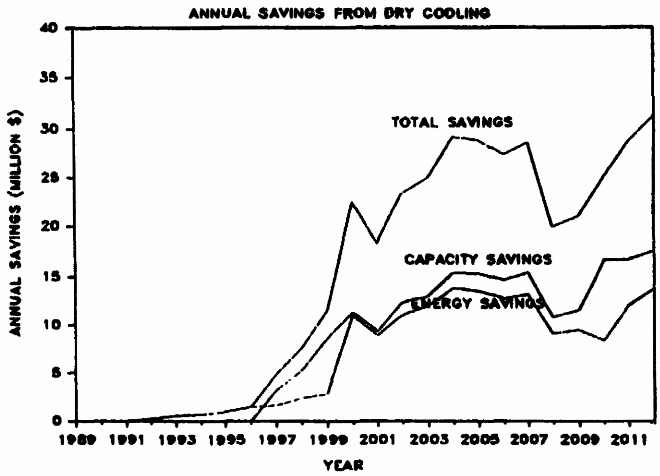

Figure 6. Annual savings from dry cooling.

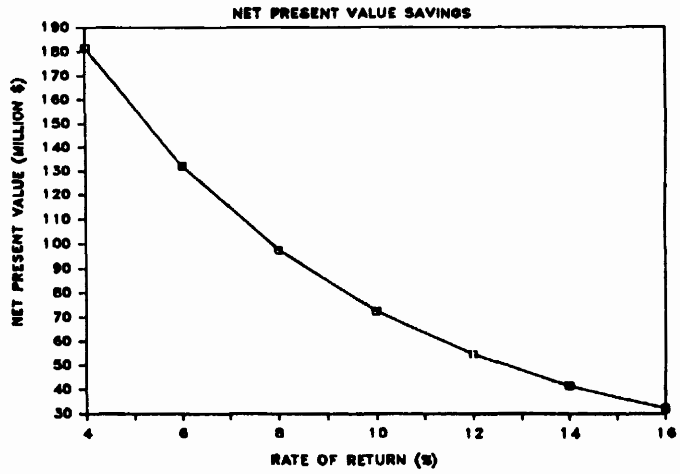

Figure 7. Air cooled condensing.

These include the following:

- An improved understanding of the long-term behavior of the steam field with respect to enhanced injection efforts, which the joint effort augmented injection program with Geysers Geothermal Company currently underway may provide.

- A detailed engineering study is required to determine the feasibility of retrofitting the existing units with dry condensing with respect to space limitations and equipment interfaces.
- The substantial savings achieved by dry condensing predicted by the model will not occur until more than 10 years after the equipment is installed. These large savings are primarily predicted on escalating energy and capacity values. The actual benefits, therefore, are dependent on the accuracies of the predicted escalation rates.

CONCLUSIONS

1. Full throttle performance tests conducted from 25 to 55 MWG determined the steam utilization and plant performance characteristics of the four geothermal units. This information is used by dispatch to minimize the steam rate penalty at low load operations.
2. Inlet pressure could be economically reduced to less than 90 psig (at reduced load) by optimizing first stage gas ejector nozzles and operating with the power plant control valves wide open.
3. A supplemental dry condensing unit retrofit is currently not planned for the NCPA geothermal project. A better understanding of both the steam reservoir physics and long-term energy and capacity values are needed to determine overall project economics.

ACKNOWLEDGEMENTS

The authors thank the NCPA management for their permission to publish this paper.

REFERENCES

Beall, J., Box, W.T. Jr. and Enedy, S.L., 1992. Recovery of injected condensate in the south Geysers field, this volume, p. 159.

Enedy, S.L., 1987. Applying flow rate decline to Geysers steam wells, 12th Workshop on Geothermal Reservoir Engineering at Stanford, p. 29-36.

Enedy, K.L., 1992. The role of decline curve analysis at The Geysers, this volume, p. 197.

Environmental Systems Corp., 1989. Steam conservation project - component testing and dry cooling feasibility study, Internal Report.

GeothermEx Inc., 1989. Reserve evaluation of the NCPA lease-hold, Internal Report.

Kline, C. and Enedy, S.L., 1992. Effect of condensate reinjection on steam chemistry at The Geysers field, this volume, p. 145.

NCPA Staff Report, 1989. NCPA Geothermal Project Status Report, Internal Report.

Smith, J.L., 1988. Development of the southeast Geysers steam field, New Zealand Workshop on Geothermal Energy.

Stone and Webster Engineering, Corp. and NCPA Staff, (1989). Gas Removal System Study, Internal Report.

Yarter, R.E., Cavote, P.E. and Quinn, D.G., 1992. Forked wellbore completions improve development strategy, this volume, p. 237.